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Renewables in the Grid

Modeling the German Power Market of the Year 2030

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(WIP)

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Workgroup for Economics and Infrastructure Policy (WIP)
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The Workgroup for Economics and Infrastructure Policy (WIP) at Berlin Institute of Technology (TU Berlin) is involved in teaching, research, and consulting work on economic policy, with a focus on infrastructure policy. WIP is headed by Dr. Christian von Hirschhausen, professor at the Faculty for Economics and Management Science, and Dr. Thorsten Beckers, assistant professor at the Faculty for Economics and Management Science.

Executive Summary

Renewable energy in Germany is on the rise. Recent changes in legislature, following the nuclear disaster in Fukushima, have accelerated the shift towards a renewable and sustainable energy supply. Offshore wind from the North and Baltic Sea is expected to reach nearly 30 GW by 2030, while the adequacy of the electricity grid to withstand this impact is already threatened today. Since the bulk of renewable energy comes from the North and East of Germany, while demand is far greater in the South and West, transmission infrastructure is poised to become the bottleneck of the German power market transformation.

This study investigates where congestion is likely to occur along the grid, and proposes different approaches to meeting the requirements of an increasing share of renewable energy generation.

A considerable amount of data for the year 2030, including, but not limited to, conventional generation, renewable generation, transmission and demand serves as the input for the welfare-maximizing DC load flow model. It consists of 40 nodes (18 within Germany, as well as 22 European countries, each modeled by a single node), 232 AC lines and 35 DC lines. The model is solved with the General Algebraic Modeling System (GAMS) for four representative weeks in 2030, one for each season of the year.

We investigate three different scenarios: the Reference Scenario, the Strategic South Scenario and the Direct Current (DC) Highway Scenario.

- The Reference Scenario is based on the assumption that 63 percent of renewable energy power will be generated in Northern and Eastern Germany by 2030, while 62 percent of load will be located in Southern and Western Germany. This situation requires a substantial expansion of transmission infrastructure from north to south.
- In the Strategic South Scenario, we explore the possibility of strategically placing renewable and conventional generation capacities to Southern and Western regions in order to make major transmission upgrades redundant.
- Finally, the DC Highways Scenario suggests that six DC super-lines from the North to the South of Germany will provide the needed relief to the Alternating Current (AC) grid. The four German TSOs are currently considering the construction of DC transmission lines for a total length of 2100 km.

The Reference Scenario confirms the need for transmission upgrades to alleviate congestion on a North to South axis. The Strategic South Scenario shows that the strategic placement of generating capacities can alleviate congestion within Germany without major transmission upgrades in the AC grid. The DC Highways Scenario displays that the construction of six DC super-lines increases inner-German line congestion but decreases interconnector congestion.

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1 Introduction

Over the course of the next 20 years, the European electricity markets will be subject to significant changes. The relationship between generation and transmission is shifting fundamentally, since the share of renewable generation is likely to triple until 2030.The integration of electricity from renewable energies (RE) poses numerous challenges: renewable generation is neither controllable, nor is it necessarily located close to the areas of major demand.

The third European energy package and the recent amendment to German Energy Law, §12a EnWG, are examples of institutional efforts to meet the requirements of changing energy markets. While these efforts are encouraging and all point in the right direction, the question remains if they will be powerful enough to incentivize efficient network reinforcement.

In recent years, countless studies examining the framework for a renewable-based energy supply in Europe have been published. There is no lack of publications providing Europe-wide and country-specific renewable energy projections, like “45 % by 2030” (EREC 2011), “[R]evolution” (Greenpeace 2010), “RE-Shaping” (Ecofys 2011), and EU Energy Trends to 2030 (EC 2009), to name a few. These studies offer useful projections of future outcomes, yet usually leave out important aspects such as the adequacy of the transmission grid.

Studies that focus on the transmission aspect of renewable integration are scarcer. The “European Grid Study 2030/2050” (Tröster et al. 2011) uses a comprehensive AC load flow model to investigate transmission needs on a European level. However, their assumptions of 68 % and 97 % of renewable generation for 2030 and 2050, respectively, appear somewhat optimistic and lack Germany-specific scenario variations. Another European-wide study is the “When the Wind Blows Over Europe – A Simulation Analysis and the Impact of Grid Extensions” (Leuthold et al. 2011).

A special focus on Germany is given in the “DENA-Netzstudie II: Integration erneuerbarer Energien in die deutsche Stromversorgung im Zeitraum 2015 – 2020 mit Ausblick auf 2025” (DENA II 2010). However, the study’s horizon is too short and it has been criticized for its lack of transparency (Jarass 2011).

The most current addition to electricity market publications with a focus on transmission infrastructure needs until 2030 is being crafted by the four German transmission system operators (50Hertz, Amprion, EnBW Transportnetze AG and TenneT TSO GmbH). By law (§12a EnWG), the TSOs are required to submit a power flow model of transmission requirements for Germany based on scenarios that have been approved by the regulatory authority, the Bundesnetzagentur. The latest scenario draft, the “Szenariorahmen für den Netzentwicklungsplan 2012” (BNetzA 2011b) has recently been determined. The altered version of the “Szenariorahmen für den Netzentwicklungsplan 2012: Eingangsdaten der Konsultation” (TSO 2011a) considers feedback from public and private institutions (Wuppertaler Institut 2011, Deutsche Umwelthilfe 2011).

The “renewable grid project” picks up this issue by focusing on Germany while embedding it in a European frame. We design compelling scenarios, which describe alternative approaches to accomplish the fundamental shift in energy supply that Germany is striving for.

This report provides an unbiased and independent assessment of the infrastructure needs in Germany until 2030, in view of the fact that the future electricity generation will be mostly based on renewable energy sources. To achieve that, we investigate long-term transmission infrastructure requirements to meet the ambitious climate targets of the German federal government. The approach that we use is the welfare-optimizing DC-load flow model ELMOD, that will be explained in detail in Chapter 2. Retrieving data sets from those mentioned studies about RE in Europe enable a realistic estimate for the upcoming development in the years till 2030. Additional insight has been gained through the calculation and projection of future generation of RE which is presented in chapter 3. The establishment of several scenarios in chapter 4 helps to resemble possible ways of integrating further RE in Europe in such an unsecure political environment. The results and interpretation of this analysis are presented in chapter 5. The final chapter consists of the conclusion as well as an outlook regarding our further research.

2 Modeling

2.1 Modeling Electricity Flows

2.1.1 The Characteristics of Electricity

To analyze the effects that different generation structures have on an electric system, it is necessary to consider the nature of power flows. An electricity grid has specific characteristics that differ from other infrastructure networks, such as water or transport facilities. Power flows do not necessarily travel the shortest distance, nor can they easily be steered. Their path depends on the resistance and reactance of the lines on which they flow and flows in opposite directions cancel each other out. Since the capacity of a line cannot be exceeded, the systemic relevance of each line needs to be accounted for to guarantee a secure supply of electricity. These specific characteristics of electricity pose great challenges to the planning of transmission infrastructure.

The flow of electricity is defined by the two Kirchhoff Laws, which define the relationship between electric tension and currents. The first rule, the Current Law, states that at each node the sum of in- and outgoing electricity flows (currents) needs to be zero. The second Kirchhoff rule, the Voltage Law also known as loop rule, says that the directed sum of the electrical potential differences (voltages) around every closed circuit (loop) equals zero.

2.1.2 Modeling Electricity

To determine the influence that one MW of generation has on the entire grid, we use Power Transfer Distribution Factors (PTDFs). The PTDFs of a line, with respect to generation from a specific node, are the product of the H-matrix and the inverse B-matrix. The H-matrix is the product of the incidence matrix and the B-Vector, including data regarding the resistance, reactance and voltage level of each line. The B-matrix is the product of the H-matrix and the incidence-matrix. These factors describe the flow through each individual line when feeding one MW into the grid at any point and taking it out at a specified hub. On the basis of the PTDFs the line flows for each line can be determined in the model (Duthaler 2007).

The original ELMOD electricity grid consists of 2120 nodes and 3150 lines (Leuthold et al. 2011) and thus results in 2120 x 3150 = 6 678 000 PTDFs. Due to the transitive properties these 9720 PTDFs are sufficient to calculate all possible flow combinations in the grid as PTDF (A -> B) = PTDF (A -> hub) – PTDF (B -> hub). The nodal PTDFs are exact, but detailed generation and demand information on a nodal basis as well as large calculation power is required if one wants to examine a one year period. For simplification we thus concluded nodes to zones. Each zone is treated like one node in the grid and in the model, this leads to 35 x 232 = 8120 PTDFs. At this aggregation the nodal-PTDFs were added up and divided by the number of nodes in the zone without the including of weighting factors.

2.1.3 Weighted PTDFs

There are different options for including weighting factors such as demand, generation or net generation (Smeers 2008). We examine the effects of choosing different weighting algorithms on the following small grid with 6 nodes and 7 lines (Figure 1).

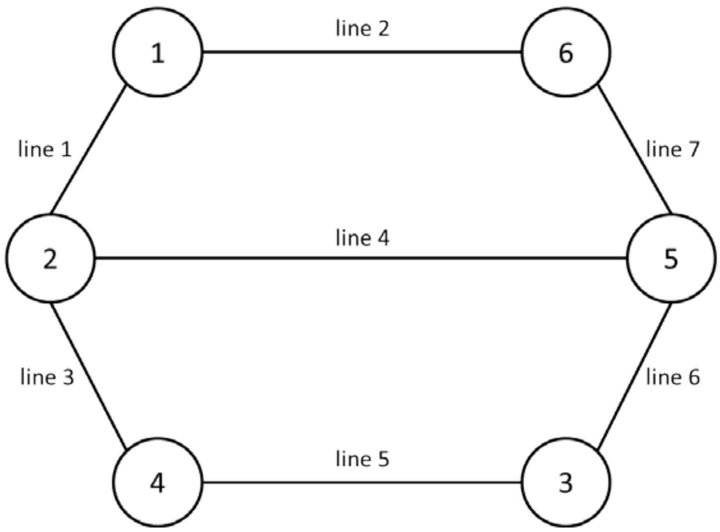

Figure 1: example grid

Source: Own depiction.

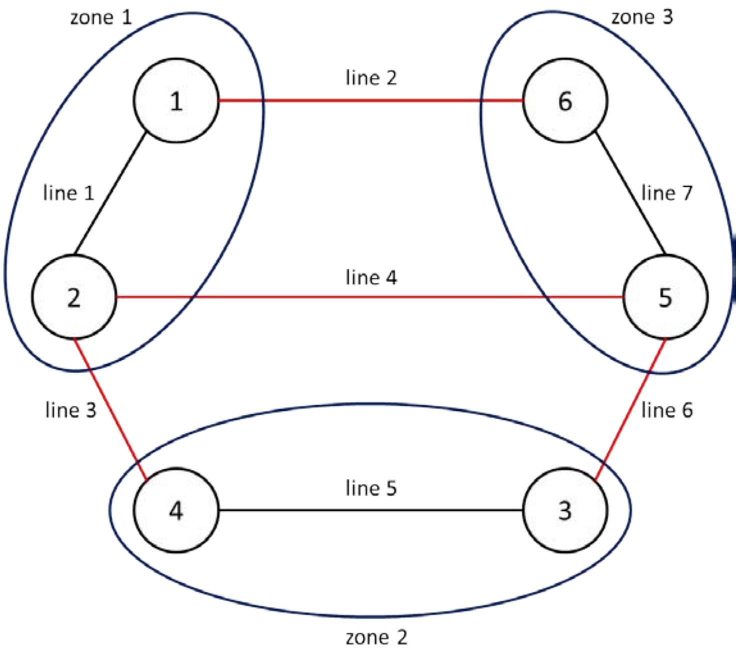

Figure 2: example grid with zones and interconnectors

Source: Own depiction.

In this simple example the values for voltage, resistance, reactance and the power flow limits are identical for each line. That implies that the weighted PTDFs are only affected by the place and value of demand and generation.

Two nodes were aggregated to one zone (Figure 2) and these zones are linked by interconnectors (red lines). In the following part the different ways to calculate the weighted zonal PTDFs for the interconnectors are being discussed.

The simplest option would be to weigh the zonal PTDFs based on electricity generation. This approach faces the problem that, especially with an increasing RE generation share, nodal generation varies a lot over time. For these reasons it seems not reasonable to use this too simplified weighting approach as it might lead to too high distortions.

Another option would be to calculate the weighting factors on the basis of the demand. In this case the weighting factor $w(n)$ is the quotient of the demand at one node $d(n)$ and the demand of the zone the node belongs to $d(z)$.

$$w(n) = \frac{d(n)}{d\ (z)} \tag{1}$$

The weighted zonal PTDF is determined by the sum of the products of the zonal unweighted PTDFs and the weighting factors (see equation (1)). The weighted factor based on the demand could have the advantage that these weighting factors do not change much over time, because the demand stays relatively constant over time. On the other hand its results might be partly misleading as some nodes might include demand centers as well as even bigger generation centers thus being a net electricity producer.

This leads to the third weighting approach which is based on generation and demand figures. The weighting factor $w(n)$ in this case is the quotient of the net generation at one node $net\ g(n)$ and the net generation of the zone the node belongs to $net\ g(z)$.

$$w(n) = \frac{net\ \ g(n)}{net\ \ gen\ \ (z)} \tag{2}$$

The weighted zonal PTDF is determined by the sum of the product of the zonal unweighted PTDFs and the weighting factors.

$$weigted\ zonal\ PTDF(l,z) = \sum_n (zonal\ PTDF(l,n) * w(n))\ \forall n\ from\ one\ zone\ z \tag{3}$$

This was already practiced by Yves Smeers in the study on the general design of electricity market mechanism close to real time from 2008 (Smeers 2008).

To analyze the dependence of the weighted zonal PTDFs two different demand and generation scenarios were created. In Table 1 and Table 2 you can see the demand and generation at each node and which node belongs to the different zones. In the year 2030 more electricity will be produced by windmills and PV. That makes the amount of generation and their location more fluctuating. In times with high wind the generation will take place mostly in the North of Germany and in times with low wind and strong solar radiation the generation will be located more in the South. This shifting generation is reflected by the two scenarios. In scenario 1 the main generation takes place on zone 3 and in scenario 2 in zone 1. The main demand remains in zone 2, as even if the generation will be fluctuating in the future, the demand will still be relatively constant. A small proportion of the demand is also changing connected with the generation, this shifting reflects demand side management (DSM). We assume that in the future a small amount of demand is also flexible, this amount can be shifted to the zone where the main generation takes place (see Table 1 and Table 2; 100 from zone 3 in scenario 1 to zone 1 in scenario 2).

node	Zone	demand	generation
node1	1	0	0
node2	1	0	200
node3	2	-700	0
node4	2	0	0
node5	3	-100	600
node6	3	0	0

Table 1: scenario 1 - main generation in zone 3

node	Zone	demand	generation
node1	1	0	0
node2	1	-100	600
node3	2	-700	0
node4	2	0	0
node5	3	0	200
node6	3	0	0

Table 2: scenario 2 - main generation in zone 1

Source: Own calculations based on GAMS.

The weighted zonal PTDFs for both scenarios were calculated with the two different weighting methods. For a better comparability the average value of the weighted zonal PTDFs for each interconnector were determined. The results are shown in Table 3and Table 4.

	average value of PTDFs		comparison
interconnector	Scenario 1	Scenario 2	percentage deviation
line2	-0.0016	0.0127	-800%
line3	0.0540	0.0683	21%
line4	-0.0048	0.0381	-800%
line6	-0.1127	-0.0984	14.5%

Table 3: average value of PDTFs - weighting based on net generation

Source: Own calculations based on GAMS.

	average value of PTDFs		comparison
interconnector	Scenario 1	Scenario 2	percentage deviation
line2	0.2042	0.1917	6.5%
line3	0.1833	0.1708	7.3%
line4	0.1125	0.0750	50%
line6	-0.2542	-0.2667	5%

Table 4: average value of PTDFs – weighting based in demand

Source: Own calculations based on GAMS.

By comparing the zonal PTDFs for the two scenarios, it becomes clear that the changing generation has a great impact on the PTDFs. The average weighted PTDFs based on the net generation change up to 800 % (line 2 and line 4) and even changes the direction of the power flow. The PTDFs weighted on the bases of demand differ less strongly and do not change the direction. Its highest deviation is line 4 with a deviation of 50 percent. This lower changing is the result of the fact that in this example the demand does not change as much as the generation and remains in both scenarios in zone 2.

Nevertheless the weighting based only on the demand is not a safe solution. The amount of generation and its location affect the power flows, which was shown by this example. These results lead to the conclusion that the weighting based on demand and generation in theory is the best one, but due to the mentioned problems not feasible in this model. This simple example shows that the weighting of PTDFs is dependent on the generation and the demand which change over time and how difficult it is to weight the PTDFs reasonable.

A solution for this problem and a field for further research are time-dependent PTDFs. The time-dependent PTDFs would change for every time t dependent on the generation and demand at t. In this case it would be possible to weight the PTDFs based on the demand and the generation and include shifting generation. The calculation of these time-dependent PTDFs though requires a large amount of information and calculation capacity.

In our case including only demand or (net) generation might distort the results while considering hourly changing net generation exceeds the calculation capacity. Therefore choosing the simplified PTDF values without weighting factors probably does result in the less distorted PTDF values.

2.1.4 N-1 Security

Electricity in Europe is not allowed to break down as this would lead to enormous costs. Thus the model has to come up with a safe solution resembling the demanded n-1 security of the network in Germany. This implies that the electricity supply is still guaranteed if one part (e.g.: line or transformer) of the system breaks down (Bundesnetzagentur 2007). These safety requirements are represented in the model by restricting the allowed maximal capacity to 80 percent of the actual capacity of each line at any time (Leuthold et al. 2008,Tröster et al. 2011).

2.2 Description of the ELMOD Model

We use ELMOD (Leuthold et al. 2011) as the mathematical base of our model. We complement it with actual data from the year 2011 and other new features to reflect a realistic integration of renewable integration. The mathematical formulation is based on an optimization problem that maximizes social welfare (consumer surplus + producer surplus) and is solved in GAMS (General Algebraic Modeling System) as a quadratic constrained problem (QCP) by the CPLEX solver. This paper presents results for four representative weeks, one for each season of the year.

Overall, we improved the clarity of the code by assigning lower case letters to exogenous parameters and capital letters to parameters that GAMS solves endogenously. The specific notations of all terms and variables are listed in Appendix 6.

2.2.1 Mathematical Formulation

2.2.1.1 Objective Function

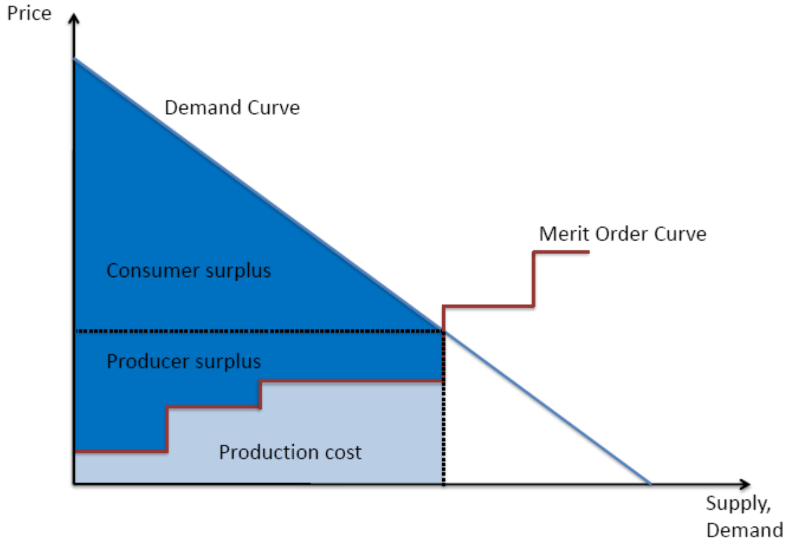

Figure 3: Welfare in an Electricity Market

Source: Own depiction based on Todem 2004.

The model uses a welfare maximizing approach that incorporates an energy balance, generation, storage, DSM, ramping, line flow constraints and a fluctuating renewables constraint. As shown in Figure 3 total welfare consists of the area between the demand curve and total costs, hence the sum of consumer and producer surpluses. In our model, various forms of costs are accounted for:

- ramping costs equal to the product of a ramping cost factor for each type of power plant and the amount of ramped up capacity.

- DSM costs, which can be calculated by multiplying the cost factor by the computed amount of DSM.

$$\max\left\{W=\begin{bmatrix}\sum\left[q\_area(t)-VAR\_\cos t(t)\right]-\sum_{t,s,n}g\_up(t,s,n)\cdot ramp\_up(s)\\ -\sum_{t,n}c\_DSM(x)\cdot DSM\_out(t,n,x)\end{bmatrix}\right\} \tag{4}$$

At each node, a reference demand and a reference price is estimated in order to approximate a linear demand function. It is then possible to calculate the area below the demand function by equation (5).

$$q\_area(t)=\sum_{n}\left[a(n,t)\cdot Q(n,t)+\tfrac{1}{2}\cdot m(n,t)\cdot\sqrt{Q(n,t)}\right] \qquad \forall t \tag{5}$$

The linear demand function is defined by $p = a + m \cdot q$, where *a* stands for the intercept of the demand curve with the ordinate and m for the slope of the demand function.

$$m(n,t) = \frac{p\_ref(t)}{\varepsilon \cdot \lambda \cdot q\_ref(n,t)} \qquad \forall n,t \quad (6)$$

$$a(n,t) = p\_ref(t) - \lambda \cdot q\_ref(n,t) \cdot m(n,t) \qquad \forall n,t \quad (7)$$

2.2.1.2 Energy Balance Constraints

Technical network limits are modeled by constraints on the power flows. The energy balance is guaranteed by a nodal energy balance constraint. Due to electric storage possibilities, demand and supply do not have to be balanced at every point in time (see 2.2.1.3 for more details on storage constraints).

$$\begin{aligned}&\sum_s G(n,s,t) + wind\_gen(n,t) + hydro\_gen(n,t) + pv\_gen(n,t) + NETINPUT(n,t)\\ &-S\_IN(n,t) + S\_OUT(n,t) = Q(n,t) - DSM\_out(n,t,x) + DSM\_in(n,t,x)\end{aligned} \qquad \forall n,t \quad (8)$$

The energy balance states that the difference between generation and demand at a specific node minus net DSM at that node must be balanced either by feeding power into the grid or into the storage if the difference is positive, or by taking power from the grid or storage if the difference is negative.

Generation Constraints:

$$G(n,s,t) \leq revision(s) \cdot g\_\max(n,s) \qquad \forall n,s,t \quad (9)$$

Equation (9) incorporates technical generation limits by stating that generation of each plant type at each node cannot be higher than the maximum net generation capacity. Net generation capacity equals gross capacity times the technology specific availability factor.

In order to obtain the generation costs, a merit order curve at each node is determined. The merit order curve is a stepwise function representing the varying marginal costs of the different technologies at each node.

$$VAR\_cost(t) = \sum_{n,s} \left[G(n,s,t) \cdot c(s) \right] \qquad \forall t \quad (10)$$

AC Flow Constraints

The flow on a specific line is determined by all net inputs into the nodes multiplied by their respective PTDF factor.

$$AC\_LINEFLOW(l,t) = \sum_n ptdf(l,n) \cdot AC\_NETINPUT(n,t) \qquad \forall l,t \quad (11)$$

The line flow constraints state that the electricity flowing through a line cannot be greater than the maximum capacity of that line, in absolute terms. Since electricity can flow in both directions and the line flow can thus be positive or negative, two separate constraints are included guaranteeing that the line flow does not exceed its capacity limit on each line.

$$AC\_LINEFLOW(l,t) \leq +AC\_p\_\max(l) \qquad \forall l,n \qquad (12)$$

$$AC\_LINEFLOW(l,t) \geq -AC\_p\_\max(l) \qquad \forall l,n \qquad (13)$$

$$p\_\max(l) = (1-\tau) \cdot p\_\max(l) \qquad \forall l,t \qquad (14)$$

As mentioned before, by reducing the maximum line capacity below its technical potential, we account for the n-1 security. The factor τ has the value of 0.2 and stands for the transmission reliability margin. Hence the term *(1-τ)* multiplied by *p_max(l)* represents the maximum capacity utilization of 80 percent that we assume for our model.

DC Flow Constraints

A similar reasoning applies to the modeling of the DC line flows. The net input into a DC line is determined by the line flows of the DC lines multiplied by their factor in the incidence matrix.

$$DC\_NETINPUT(n,t) = \sum_{dcl} DC\_INCIDENCE(dcl,n) \cdot DC\_LINEFLOW(dcl,t) \qquad \forall n,t \qquad (15)$$

As in the case of AC lines, DC lines have a certain technical power limit that cannot be exceeded at any point in time. Therefore, two constraints are included guaranteeing that the power flowing through a line does not exceed its technical power limit.

$$DC\_LINEFLOW(dcl,t) \leq +DC\_p\_\max(dcl) \qquad \forall dcl,t \qquad (16)$$

$$DC\_LINEFLOW(dcl,t) \geq -DC\_p\_\max(dcl) \qquad \forall dcl,t \qquad (17)$$

2.2.1.3 Storage Constraints

As power in- and outflows are limited, two constraints are included stating that at each point in time at each node, storage in- and outflow cannot be greater than the corresponding storage power limit.

$$S\_IN(n,t) \leq s\_in\_\max(n) \qquad \forall n,t \qquad (18)$$

$$S\_OUT(n,t) \leq s\_out\_\max(n) \qquad \forall n,t \qquad (19)$$

Since it is not possible to take out more energy of the storage plant than has been stored in before, we defined a storage level variable in our model. The storage level at time t is equal to the storage level in time t-1 plus the net storage inflow at time t (20) and always has to be greater than zero. In order to account for losses that occur when storing energy, the storage inflow has to be multiplied by a conversion efficiency factor *s_eff*.

$$S\_Level(n,t) = S\_Level(n,t-1) - S\_OUT(n,t) + S\_IN(n,t) * s\_eff \qquad \forall n,t \qquad (20)$$

The storage level can never exceed its maximum capacity which is stated in equation (21).

$$Scap\_\max(n) \geq S\_Level(n,t) \qquad \forall n,t,t^* \leq t \qquad (21)$$

Our model assumes that, over all periods, power in- and outflows, corrected by the conversion efficiency factor, need to be balanced and thus their sum is equal to zero.

$$\sum_t S\_IN(n,t) \cdot s\_eff = \sum_t S\_OUT(n,t) \qquad \forall n \qquad (22)$$

2.2.1.4 Demand-Side-Management Constraints

$$DSM\_in(n,t,x) \leq dsm\_\max(t,n,x) \qquad \forall n,t \qquad (23)$$

$$DSM\_out(n,t,x) \leq dsm\_\max(t,n,x) \qquad \forall n,t \qquad (24)$$

In our model, we assume that consumers have the possibility to shift a maximum of five percent of their electricity consumption for up to two hours through demand side management (DSM). When shedding load, consumers get compensated depending on the amount of demand is shifted. Specifically, we assume that the more load they shed, the more they get compensated. Thus, for the first two percent they get three €/MW, for the next two percent they get five €/MW and, finally, for the final one percent they receive ten €/MW. Consequently, equations (22) and (23) appear three times in the model with respective *dsm_max* values of two percent, two percent and one percent. The compensation costs are included in the objective function. Equation (22) then stands for the maximum amount of demand that can be added at node n and at time t and equation (23) represents the maximum amount of demand that can be shifted.

$$\sum_{t^*=t-t\_dsm}^{t+t\_dsm} \left[DSM\_in(n,t^*,x) - DSM\_out(n,t^*,x)\right] = 0 \qquad \forall t,n \qquad (25)$$

t_dsm is the maximum time frame, in which demand can be shifted. In our model, this time frame equals two hours and thus the factor *t_dsm* is equal to one. Equation (22) represents the DSM balance: The sum of the shedded amount of demand from the last hour and the amount of demand that is added to the next hour has to be equal to zero in all times t and at all nodes n.

2.2.1.5 Ramping Up Constraints

$$g(t,s,n) - g(t-1,s,n) \leq ramp\_limit(s,n) \qquad \forall t,s,n \qquad (26)$$

$$g(t,s,n) - g(t-1,s,n) \leq g\_up(t,s,n) \qquad \forall t,s,n \qquad (27)$$

The ramping up constraints limit the amount of capacity that can be ramped up in one time period depending on the constraint of each technology. The positive variable *g_up(t,s,n)* hereby stands for the ramped capacity compared to the previous time period, leading to additional ramping costs included in the objective function.

2.2.1.6 Fluctuating Renewables Constraint

One of the biggest problems of renewable energies such as wind and photovoltaic is the difficulty to predict their future generation. These uncertainties are evened out by flexible gas turbines that are able to ramp up in very short time intervals. This characteristic is modeled in equation (25). It states that the sum of wind, pv and gas generation in Germany in one period always has to be larger than the generation of wind and pv in the period before. In other words, a drop of fluctuating RE from one period to the other has to be evened out through additional gas production.

$$\sum_n \left[wind\_gen(t,n) + pv\_gen(t,n) + G(t,"Gas",n)\right] \geq \sum_n \left[wind\_gen(t-1,n) + pv\_gen(t-1,n)\right] \qquad \forall t \qquad (28)$$

3 Data

3.1 Electricity Demand

According to the Federal Energy Concept for an Environmentally Sound, Reliable and Affordable Energy Supply (BReg 2011), the German government is aiming for a demand reduction of 25 percent between 2008 and 2050. This amounts to approximately 16 percent until 2030, when applying the compound annual growth rate. Based on net electricity consumption of 538 TWh in 2008, this leads to a demand of 463 TWh in 2030 in Germany. On a European level, our model uses hourly load values of the year 2010 provided by the European Network of Transmission System Operators (ENTSO-E2010a).

Total German demand is attributed to the 18 model nodes (taken from the DENA-grid study, referred to as “DENA-zones” hereinafter) based on population data. See Figure 4 for an overview of the 18 nodes.

3.2 Electricity Grid

3.2.1 Evolution of the European Grid

In order to model the German power market of the year 2030, we need to make assumptions about the evolution of the electricity grid, both for Germany and the rest of Europe. The following section outlines the additions that we have made to the grid of 2011.

A number of grid expansion projects that are currently still under consideration, in planning or in an early construction phase are applied exogenously to the model. German legislature, ENTSOE and regional TSO data are the basis for our perception of the 2030 European grid.

The Energieleitungsausbaugesetz (EnLAG 2011) prioritizes a series of national projects that have currently reached either late planning or early construction phases. Even though some projects are encountering significant delays and public resistance, the probability of their completion by 2030 is very high, justifying their consideration in the model.

For transmission projects on an international level, only lines that connect two countries and have a high probability of completion are considered. ENTSOE’s Ten Year Network Development Plan (TYNDP) identifies a number of projects, of which only several are picked for our model; see Appendix 1 and 2 for a complete list of included projects. The upgrade of existing or construction of new lines between Germany and the neighboring Belgium, Czech Republic, Denmark, France, Austria, Poland and Switzerland will provide additional power exchange capacities and augment security of supply. Since the most long-term of the projects are to be commissioned before 2017, we assume them to be completed and operational by 2030.

Figure 5 depicts the transmission network topology within Germany and its neighboring countries.

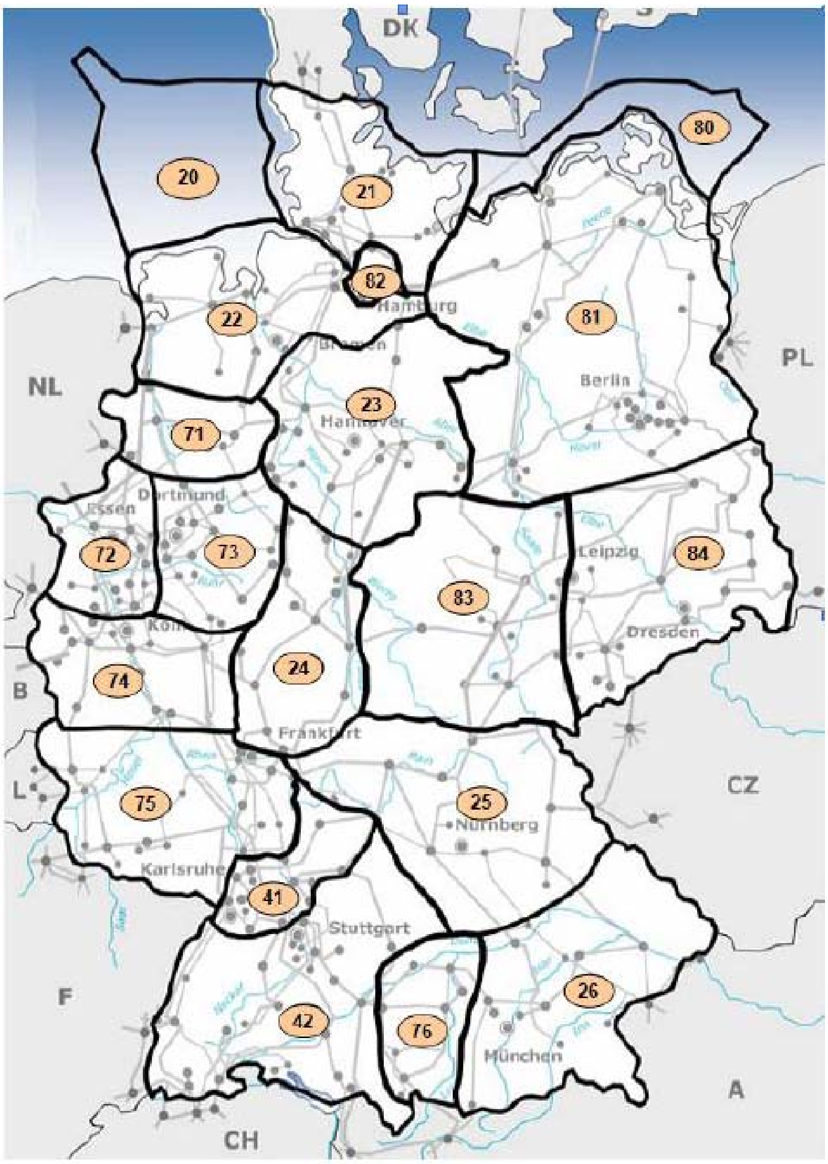

Figure 4: Dena Zones

Source: DENA 2010.

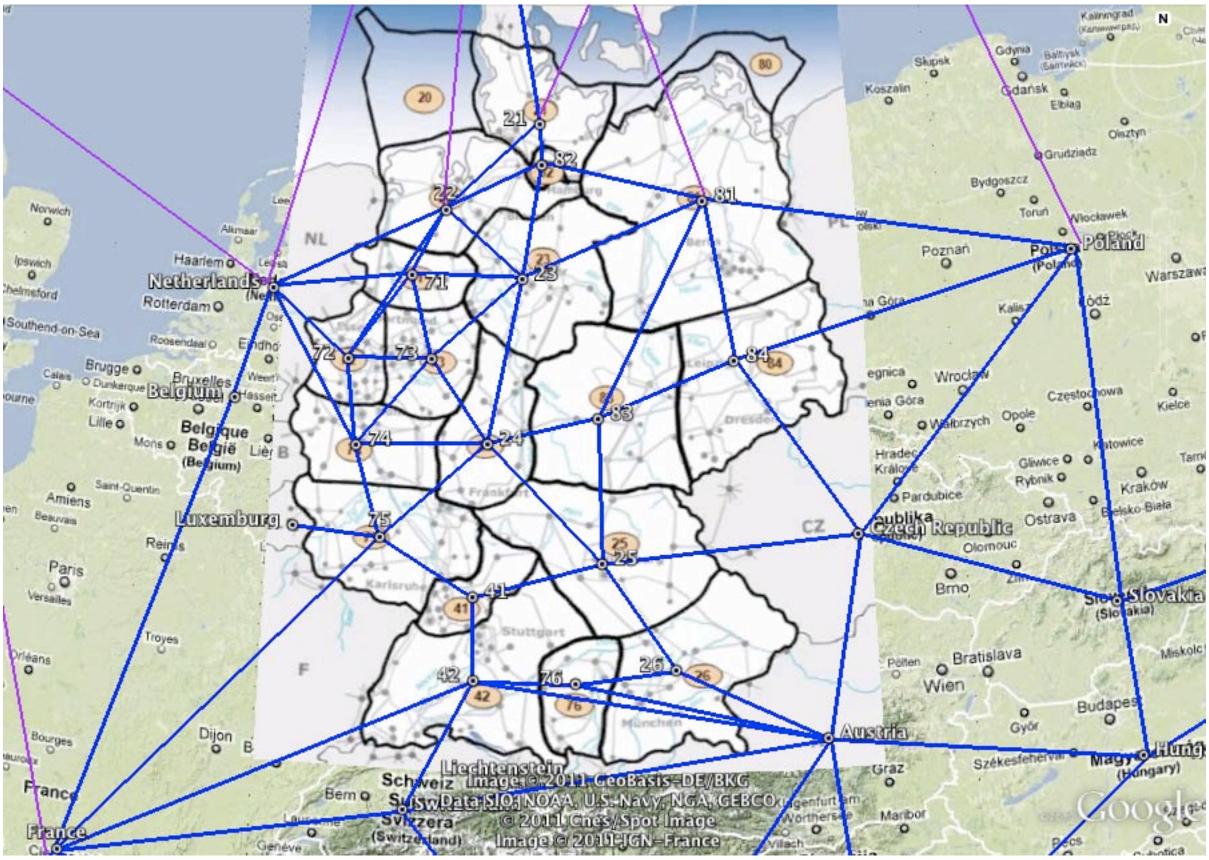

Figure 5: Dena Zones, Model Nodes, and Domestic Transmission Topology

Source: Own depiction based on DENA 2010 and Google Earth.

3.2.2 Costs of Transmission Grid Expansion

The assumed costs of upgrading the transmission grid depend on the length, type, capacity and terrain of the underlying transmission lines. As we consider mostly AC-lines, especially variable costs of the network expansion are important. HVAC is the cheapest technology of power transmission and well established in today's power system. Hence, no large cost reductions are expected throughout the modeling horizon. Based on already built or pending project cost specifications (ICF 2002 and Tröster et al. 2011), we assume the following costs:

	Additional Converter Costs [€/MW]	Variable Cost [€/MW/km]
HVAC (Overhead) line)		400
HVDC (Cable)	150000	1500

Table 5: Upgrade Costs of Transmission Lines

Source: Cost assumptions based on Tröster et al. 2011.

The model prioritizes the upgrade of existing HVAC routes, however some scenarios may require major capacity extensions. In this case additional HVDC connections are needed. In most cases the actual expansion cost can be calculated if length and terrain is known. To represent different geographical characteristics of terrain, grid expansion costs are multiplied with a factor:

* 1.5 for mountainous regions (e.g. all lines connecting Austria)

* 1.1 for populous regions (e.g. North Rhine-Westphalia)

* 1.3 for nature conservation areas (e.g., the Uckermark)

3.2.3 Comparison AC vs. HVDC for Bulk Power Transmission

Today's existing technologies can carry up to 5000 MW (HVDC, 600 kV) and 2000 MW (AC, 800 kV). (Weimers 2004). For a point-to-point bulk transmission at extra-high voltages we compare AC 800 kV and DC 500 kV / 600 kV. With regard to expected future transmission problems in Germany, both solutions are imaginable. The evaluation of design aspects for transmission lines can be divided into economical, electrical and mechanical aspects. Besides technology costs and public acceptance the integration into the exciting 380 kV grid has a superior importance. This evaluation contains the consumption of reactive power, power losses, impact on system reliability, redundancy and expansion options.

For a long-distance power transmission HVDC lines have many advantages compared AC lines with the same power rating. While HVDC lines are mainly limited by a maximum conductor temperature the capacity of AC lines is also limited by high reactive power consumption. This leads also to the required number of lines in parallel and hence the investment cost.

Power Rating: 3000 MW	AC 800 kV (2 Single Ckt)	HVDC 500 kV (Bipole)	HVDC 600 kV (Bipole)
Transmission line costs (M€/km)	1.22	0.7	0.8

Table 6: Transmission Line Costs

Source: Assumptions based on Bahrmann 2008 and ABB 2011.

It is obvious that HVDC lines are cheaper than AC lines mainly as a result of a lower number of parallel lines needed. This cost advantage is reduced by the cost for converter station costs. Hence, at a given power rating and length it is beneficial to choose a HVDC line. Dena II concludes this point at 400 km for a transmission capacity up to 4000 MW and even lower (but not defined) for lines with higher capacities.

For AC lines there are nearly no further cost reductions and research necessary since in general the AC technology is in operation for a very long time. To tap the full potential for DC lines over 600 kV it is essential to focus on the converter stations and equipment.

3.3 Electricity Generation

The "Renewable Energy Policy Country Profiles" study (RE-Shaping), was used as a consistent basis for RE production data in Europe. The study was published by ECOFYS, Fraunhofer, Energy Economics Group and LEIinin 2011 (Ecofys 2011). It predicts the realizable potential of electricity generation by 2030 per technology (in ktoe) for EU-27 countries. These projections were directly derived from the National Renewable Energy Action Plans (NREAPs) for each country in the year

2020, and reflect the official RE target of each country. The 2030 forecasts also take into account existing national RE support policies as well as expert opinions, providing a higher level of detail than other comparable studies.

We converted electricity generation data for wind, solar, hydro, wave and tidal, geothermal and biomass into installed capacity using technology- and country-specific full load hour assumptions taken from the NREAPs.

Since biomass and geothermal are more or less dispatchable technologies, their generation is controllable and does not need to be forecasted. For the fluctuating renewables on the other hand, we calculated feed-in-series for 8760 hours to model the actual generation mix over the course of a year. See section 3.3.2 for more detail on renewable feed-in series.

3.3.1 Renewable Energy Data

The recent projections by the 2011 RE-Shaping study are the basis for our Reference Scenario. We concur with the authors that 2906 TWh of renewable generation is an optimistic yet realistic assumption for the EU 27 in the year 2030. For a detailed breakdown of capacities on a member state level, see Appendix 3.

Both on- and offshore wind contribute a significant portion of total renewable generation, at 19 percent and 17 percent, respectively. Another 16 percent of photovoltaic generation increases the total portion of fluctuating renewables to 52 percent.

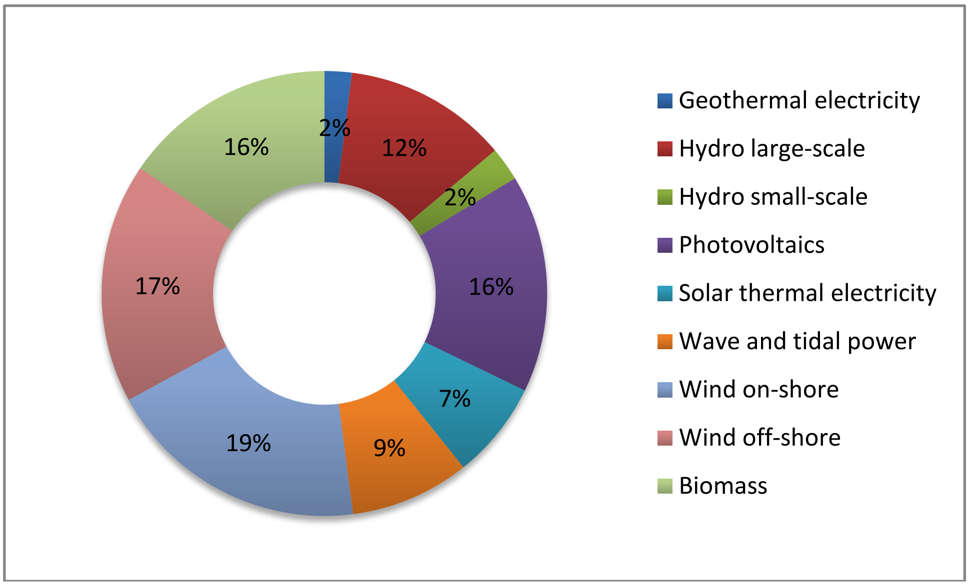

Figure 6: Technology Shares of Total RE Generation for 2030 on a EU 27 Level

Source: Own depiction based on Ecofys 2011.

Since all countries except for Germany are modeled as a single node in the GAMS model, the geographic distribution of capacity, renewable or conventional, is not relevant. The entirety of generation capacity is thus aggregated in the single node.

For Germany, however, a greater level of detail is needed, not only to guarantee the highest possible accuracy, but also to satisfy our model's architecture. Total capacity must be broken down on the 18 DENA nodes in a way that is plausible given geographic potential and political will.

As there is no exact data on the regional distribution of renewable generation in Germany in the "RE-Shaping" study, this information was adopted from the Table 7of the TSO scenario pathway mentioned earlier (TSO 2011a). After applying that distribution onto the capacities given in the RE-Shaping study, we obtain the regional breakdown of 2030 renewable capacity in Germany (see Table 7).

DENA Zone	Geo-thermal	Hydro-power	Photo-voltaics	Wave &Tidal	Onshore Wind	Offshore Wind	Biomass	Sum
21	0.61	0.00	2.74	1.74	5.47	10.97	0.25	21.76
22	0.00	0.05	2.04	1.74	2.47	5.48	0.54	12.32
23	0.00	0.06	2.51	0.00	2.60	0.00	0.59	5.76
24	0.24	0.00	4.08	0.00	1.11	0.00	0.20	5.63
25	0.15	1.85	10.58	0.00	0.50	0.00	0.92	14.01
26	0.10	1.23	7.40	0.00	0.34	0.00	0.61	9.69
41	0.10	0.49	3.04	0.00	0.63	0.00	0.33	4.59
42	0.20	0.98	5.83	0.00	1.26	0.00	0.65	8.93
71	0.00	0.03	1.37	0.00	1.41	0.00	0.32	3.13
72	0.00	0.05	2.97	0.00	1.73	0.00	0.39	5.14
73	0.00	0.04	2.23	0.00	1.30	0.00	0.29	3.86
74	0.06	0.02	2.31	0.00	1.02	0.00	0.25	3.65
75	0.30	0.00	4.45	0.00	0.97	0.00	0.25	5.97
76	0.05	0.62	3.70	0.00	0.17	0.00	0.31	4.84
81	0.00	0.00	2.92	1.74	4.48	5.48	2.89	17.51
82	0.00	0.12	0.00	0.00	0.04	0.00	0.12	0.29
83	0.00	0.00	2.46	0.00	2.23	0.00	0.43	5.12
84	0.00	0.12	2.06	0.00	1.65	0.00	1.35	5.19
Sum	1.82	5.66	62.69	5.22	29.39	21.93	10.68	137.38

Table 7: Breakdown of RE Generation Capacities on Dena Zones, 2030 in GW

Source: Own Calculation based on Ecofys 2011.

3.3.2 Generating Hourly Generation Data

Unlike conventional fuels, wind and solar power cannot be controlled or dispatched; their generation is at the mercy of the seasons and the weather. Once the target amount of installed (fluctuating) renewable capacity has been determined, hourly generation values need to be derived from it. This section describes the methodology behind the creation of generation time series for wind and solar technologies and hydropower.

3.3.2.1 Methodology of Wind Power Derivation

The following section describes the methodology to derive aggregate wind power feed-in time series for each node of the model. The general approach is to derive power output from a representative wind park as a function of wind speed. The total amount of electricity generated by wind varies across scenarios as outlined in the individual scenario presentations. Given the amount of produced energy per year, the temporal pattern of production throughout the year must be determined. The challenge of the following methodology is to “calibrate” the representative wind farm in a way that their energetic output E corresponds to the wind electricity generation defined in each scenario on the one hand and to obtain a realistic amount of installed capacity P_{nom} on the other hand. Connected by the number of full load hours (FLH), the latter ones represent the key quality indicator of this methodology.

The first subsection deals with the data sources and the methods applied to derive the hourly wind speeds at each node. Meteorological data on wind speeds at a height of 10 m over ground are used and extrapolated up to an average hub height.

The second subsection describes the representative wind farm with its technical properties. An average representative wind turbine is created which transforms wind speed data into actual electricity input to the network.

3.3.2.1.1 The Creation of Wind Patterns

Meteorological Dataset

To include correlation effects between the output curves of wind power and solar power, wind data has been taken for the common reference year 2005. 6-hourly wind data is retrieved from ECMWF ERA Interim Re-Analysis for 2005 (Dee et al. 2011). Hours in between the 6 hour steps are interpolated by setting them constantly to the same value as the 1st hour of each 6 h set.

Wind speed data is exported as NetCDF file from ECMWF’s ERA Interim Re-Analysis and post-processed in Excel using an Add-in for Excel to be able to read NetCDF files (NetCDF 2011). The data consists of vector, zonal and meridional wind speed data partly observed and partly interpolated.

The ERA-Interim Re-Analysis has a resolution of N128 (128 latitude circles pole to equator). Data is available for a coordinate grid of 1.5 to 1.5° density. Ca. 18 points are available for Germany. The appropriate grid points for this study are extracted and allocated to DENA zones, corresponding to the geographic coordinates. Offshore and onshore wind speeds are treated separately for Germany, not the least since offshore wind speeds are almost consistently well above onshore wind speeds in the data. Note that the Interim Re-Analysis consists in a mixture of forecast and actual measures of grid cells cover a large area and thus build average values for specific grid cells.

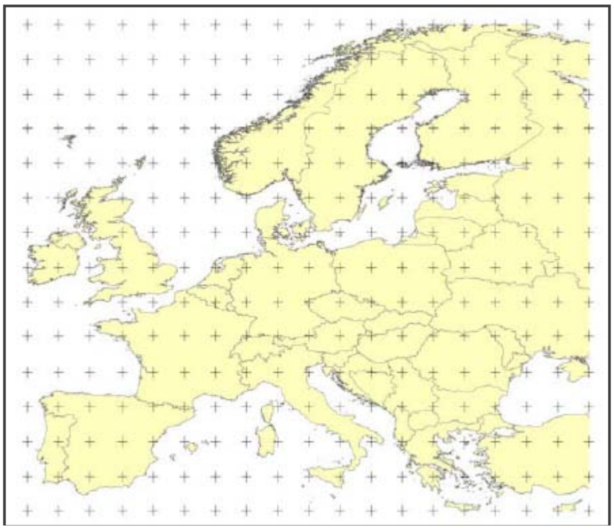

Figure 7: Grid Cell Structure of a T-62 Gauss Grid

Source: TradeWind 2008.

Extrapolation of Wind Speeds to Hub Height

ECMWF provides U and V component wind speed data only for 10 m surface level. In order to estimate the air speed and output for the actual height of a typical wind turbine, a wind shear formula is used, which relates wind speeds of different altitudes depending on a specific surface roughness level (Quaschning 2009, DWIA 2011). The wind speed at a certain height above ground level is defined as:

$$v(h) = \frac{\ln(\frac{h}{z_0})}{\ln(\frac{h_{ref}}{z_0})} \qquad (29)$$

V Wind speed at height h above ground level.

v_{ref} Reference speed, i.e. a wind speed we already know at height h_{ref}

h Height above ground level for the desired velocity, v.

Z_0 Roughness length in the current wind direction. Refers to the lengths of swirls.

h_{ref} Reference height, i.e. the height where we know the exact wind speed v ref

Roughness lengths are standardized classes (DWIA 2011). We use roughness lengths of 0.0024 m for onshore turbines and 0.0002 m for offshore turbines.

3.3.2.1.2 The Representative Wind Farm at Each Node

A power output curve designates the relation between wind speed and output and it is most prominently influenced by the power coefficient c_p. The power coefficient describes that not all wind power input can be harvested. It can amount to a maximum of 59.3 % (Betz's law) and reaches its peak depending on the configuration of the wind turbine.

Onshore Turbines

A sixth-order polynomial approximation is used to approximate a power output curve. Such approximation reflects the exponential relation of wind output and wind speed while at the same time allowing for a maximum output level. The following paragraph describes its mathematical derivation:

We use power coefficients of an Enercon wind turbine E-101 (Enercon 2011), which is used as a representative average wind turbine. However, expected hub heights and rotor diameters are corrected for the year 2030, in line with SRU / DLR 2010. The rotor diameter of an E-101 is 101 m and rated power figures at 3 MW. With the rotor diameter 116.7 m and hub height 127 m (SRU / DLR 2010), we derive a rated power capacity of 4.8 MW, roughly in line with the assumption of 4.4 MW onshore in SRU / DLR 2010. The power output curve is obtained by multiplying the theoretic kinetic energy potential of the wind (depending on rotor diameter and wind speed) with the power coefficient c_p (3). It may be surprising that we assume c_p to be constant, even though it depends on the rotor geometry. This assumption turns out to be applicable, because the general shape of the c_p curves today is already close to the optimal limits, set by the Betz' law. It is probable that new generations of wind turbines with enhanced rotor diameters will be constructed in a way to maintain these characteristics. Finally, (3) is approximated by a 6^{th} order polynomial with a regression coefficient $R^2 >$ 0.99. This approximation is only done for technical reasons to speed up the calculation process. Figure 8 shows the resulting power output curve for the representative onshore wind turbine.

$$P_{th,i} = \frac{1}{2} v_{i,j}^3 \frac{\pi}{4} d^2 \rho_L \tag{30}$$

$$\begin{aligned} P_{real,i} &= c_p \eta P_{th,i,j} \\ c_p &: f(v) \end{aligned} \tag{31}$$

P_{th}	Theoretic maximum wind power, defined by kinetic energy content of air masses
v	Wind velocity
d	Rotor diameter
ρ	Average wind density (fix at 1,225 kg/m^3)
c_p	Power coefficient at wind speed v
η	Other losses (not concerned in c_p)
P_{real}	Real wind power injected to the network

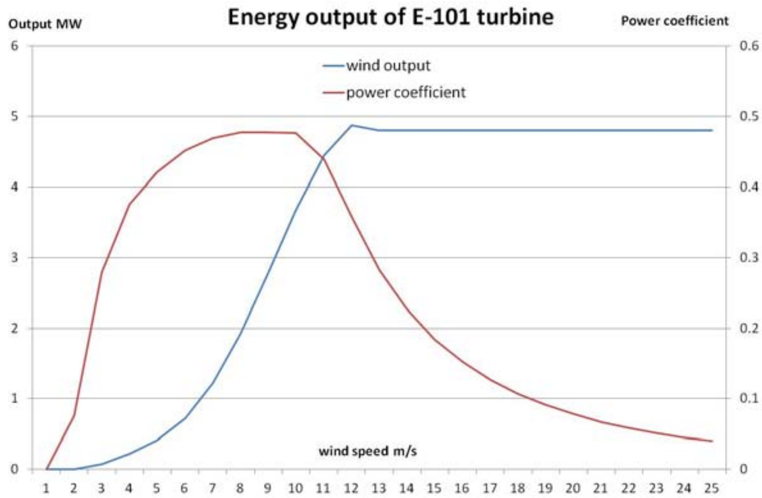

Figure 8: Power Output Curve of an E-101 Onshore Wind Turbine with 4.8 MW Rated Output

Source: Own production.

Each node j is now supposed to have its own specific number of installations n_j of the "representative" wind generator derived above. Each node's real injected power now sums up to (32):

$$P_{real,i,j} = n_j P_{real,i} \tag{32}$$

n Number of installations

j Index for nodes

The generation of offshore turbine output curves follows the same methodology as described above for onshore turbines. The only variation lies in rotor diameter and hub height, leading to a higher theoretical kinetic energy content of the wind. For offshore turbines, we assume a rotor diameter of d = 175 m at hub height h = 128 m, which results in ca 9.5 MW rated output, almost as in SRU / DLR (2010). The polynomial, created out of (31), defining the turbine characteristics is modified but keeping the aerodynamic characteristics constant by applying the same c_p as for onshore turbines. A sensitivity analysis concerning the energy output of two extremes of different aerodynamic design types can be found in SRU / DLR 2010. Availability of turbines is set at 100 %. Losses related to cables and shading make up a loss rate of 15 % as assumed in SRU / DLR 2010.

Operating Wind Range

Cut-in and cut-out wind speeds can be found in Hau 2008 and DENA 2010. For onshore turbines we set cut-in wind speed at 4.5 m/s and rated wind speed at 12.5 m/s (DENA 2010, Hau 2008). For offshore, a 3.5 m/s cut-in wind speed and 12.5 m/s rated wind speed are used (DENA 2010). In both cases, cut-out wind speed figures at 25 m/s, a wind speed level which is not attained in the actual data. In general, the given values are quite flexible, according to Hau 2008 (p. 594).

Calibration

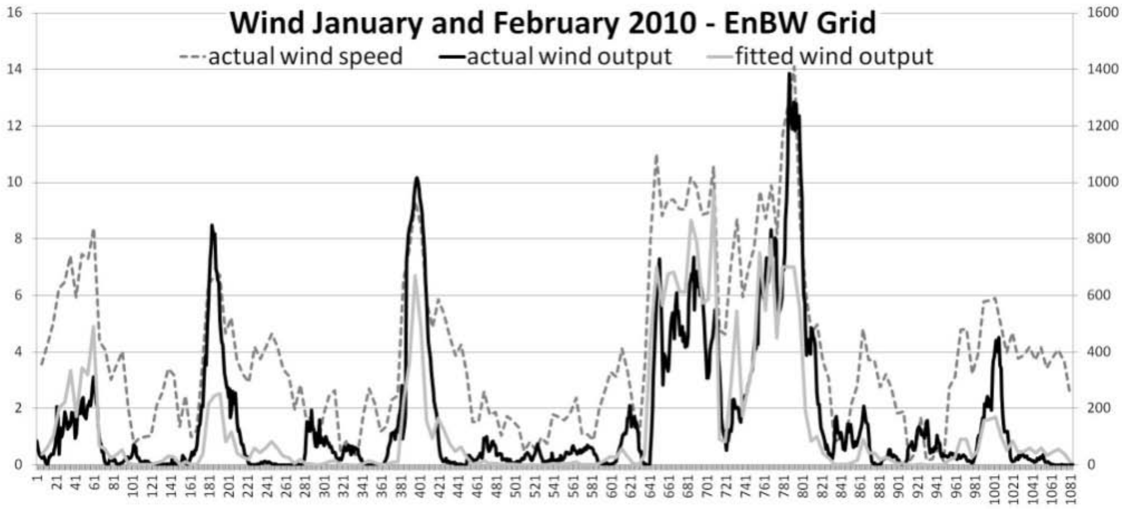

Figure 9: Actual and Fitted Wind Output in 2010

Source: Own production.

We use actual feed-in data of spring 2010 to validate our simulation method. The hourly feed-in-data is compared to the 6-hourly energy output of the representative wind farms at each node. An R^2 of 79 % can be achieved with the simulation method in the specific case of the EnBW transmission grid region in 2010. The value is slightly lower in other grid regions.

3.3.2.1.3 Resulting Installed Capacity

Derivation of Full Load hours

Installed capacities of wind turbines relate to wind speed via the following equation:

$$P_{real,i,j} = c_p \cdot \eta \cdot \frac{1}{2} \cdot v_i^3 \cdot \frac{\pi}{4} \cdot d^2 \cdot \rho_L \cdot n_j \tag{33}$$

where

- η all losses not contained in the power coefficient c_p.
- d Rotor diameter
- ρ_L Air pressure =1,225 m³/kg
- n Amount of wind turbine

All energy produced over the entire year E_a is computed as follows:

$$E_a = \sum_{j=1}^{n} \sum_{i=1}^{8760} \left[c_p \cdot \eta \cdot \frac{1}{2} \cdot v_{i,j}^3 \cdot \frac{\pi}{4} \cdot d^2 \cdot \rho_L \cdot n_j \right]. \tag{34}$$

Installed capacity P_{nom} can be derived through the number of turbines.

$$P_{Nenn,inst} = n \cdot 4,8MW$$

We are now able to calculate the Full load hours of a representative German wind farm, that consists only of the mix of average type of onshore/offshore wind turbines:

$$\begin{aligned} FLH_{Wind} &= \frac{E_a}{P_{Nenn,inst}} \\ &= \frac{\sum_{i=1}^{8760} \left[c_{p,i} \cdot \eta \cdot \frac{1}{2} \cdot c_{w,i}^3 \cdot \frac{\pi}{4} \cdot d^2 \cdot \rho_L \cdot n \right]}{4,8MW \cdot n} \\ &= \frac{\eta \cdot \frac{1}{2} \cdot \frac{\pi}{4} \cdot d^2 \cdot \rho_L}{4,8MW} \sum_{i=1}^{8760} \left[c_{p,i} \cdot c_{w,i}^3 \right] \end{aligned}$$

3.3.2.2 Photovoltaic Time Series

The following section describes the methodology applied to generate the hourly supply of photovoltaic power over the year. As for all types of energy, geographical zones have been defined and power supply within the zone has been aggregated. For each zone and each scenario exists one hourly supply row over the whole year (8760h) that represents the actual (hourly mean) real power input in the power network. Due to the hourly scaling, the values in each point of time can either be interpreted as MW or MWh.

The generated energy values of the Reference Scenario have been taken from the RE-Shaping study mentioned earlier. As this consists of yearly sums of PV energy per country, we developed the following methodology to derive a temporal distribution over the year.

In each hour j, the real power injection depends on the nominal installed capacity and the meteorological circumstances, namely:

- The irradiation on the inclined panels
- Other losses and efficiency reductions that can be aggregated to a general performance ratio (PR) (Quaschning 2009)

The real power injection at each hour I can be derived by formula (Quaschning 2009):

$$E_{i,j} = 1h \cdot P_{real,i,j} = 1h \cdot P_{Nom,j} \frac{H_{inc,i,j}}{1000 \frac{W}{m^2}} PR_{2030} \tag{35}$$

•	PR_{2030}	Mean Performance Ratio in 2030 (Leitstudie 2010)	
•	E	Injected electricity	[Wh]
•	P_{Nom}	Nominal installed capacity	[W]
•	H_{inc}	irradiation on inclined surface (SoDa 2005)	[W/m²]
•	i	index for hours in one year	
•	j	index for a geographical region (node)	

Summed up over the whole year, the given RE-Shaping value equals for a region/node j:

$$E_{a,j} = \sum_{i=1}^{8760} 1h \cdot P_{real,i,j} = \sum_{i=1}^{8760} 1h \cdot P_{Nom,j} \frac{H_{inc,i,j}}{1000 \frac{W}{m^2}} PR_{2030} \tag{36}$$

The latter part of the formula can be interpreted as the full load hours (FLH) over the whole year for a certain region j:

$$FLH_{a,j} = P_{Nom} \frac{\sum_{i=1}^{8760} H_{inc,i,j}}{1000 \frac{W}{m^2}} PR_{2030} \tag{37}$$

With the mentioned data sources, we are able to recalculate an effective nominal capacity in 2030:

$$\frac{E_{a,j}}{FLH_{a,j}} = P_{Nom,j} \tag{38}$$

By setting (38) into (35) we are now able to compute the hourly energy input, that is in the sum consistent with the total predicted energy output from our data sources (Ecofys 2011).

The regional resolution varies between Germany and the rest of Europe. For Germany, specific local irradiation data has been used for a region of a size that equals to the surface of an average DENA zone. Coordinates of a representative geographical center point have been chosen and historic irradiation data has been retrieved from SoDa 2005 for the year 2005. For countries other than Europe, just one representative geographic point represents each country. Historic irradiation data has been retrieved from SoDa 2005. The following figure (Figure 10) gives an overview about the exact representative coordinates:

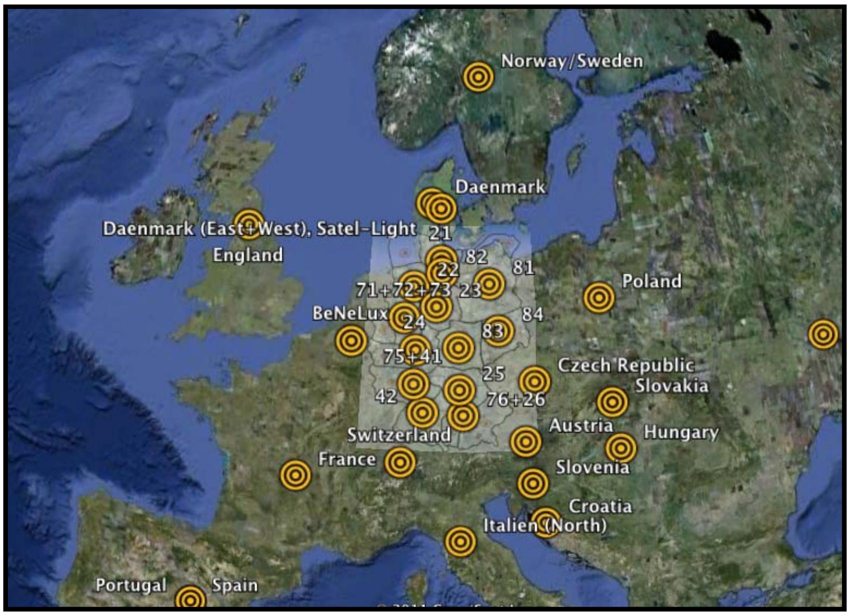

Figure 10: PV Data Coordinates

Source: Own Visualization through Google Earth.

$H_{inc,i,j}$ varies with the position of the sun, depending on the angle between the perpendicular position of the panel towards the sun rays and its real position. Additionally it varies with the panel`s azimut angle. Panel positions vary within and between the countries. To simplify the calculations we calculated a mean inclination of 25° and an azimut angle of 155° based on distributional data from DENA 2010, which all retrieved data from SoDa 2005 bases on.

3.3.2.3 Hydropower Generation

Hydropower, as opposed to solar or wind power, has a quite continuous generation profile, so there is no need for an accurate hourly generation time series. Still, seasonal variations in generation can be observed, so a generation profile by month was adopted. The profile will not change significantly until 2030 as the geological parameters, such as the rainfall series, can be assumed to remain constant.

Generation data from the years 2008, 2009 and 2010 was extracted from Eurostat (Eurostat 2011) and used as a basis for the time series calculations of hydropower. The arithmetic mean of monthly generation for the three years was determined and a monthly distribution was derived for each country of the EU-27 states.

Since Switzerland, the Ukraine and Croatia are not listed in Eurostat, we refer to documentation from the Swiss Federal Office for Energy (BFE 2011) and the Ukraine State Statistics Committee. Croatian data is either non-existent or excessively unreliable, so an approximation of the Slovenian distribution was used.

We then apply the distribution of monthly generation to the generation data given in the RE-Shaping study. Subsequently, the installed capacity for each month in each country was calculated by applying the full load hours given in the NREAPs (NREAP 2010). For the non-EU27 countries, the installed capacity and its expansion potential until 2030 were sought directly from government or private publications. Switzerland's installed hydropower capacity was taken from the Federal Office for Energy (BFE 2011). For Norway, the present-day capacity was taken from Eurostat (Eurostat 2011) and the expansion potential from the Centre for Environmental Design of Renewable Energy (CEDREN 2010). Ukraine's installed capacity was acquired from the Energy Strategy of the Ukraine until 2030, published by the EU financed project ESBS (ESBS 2006). For Croatia the generation was taken from a survey by the Croatian Chamber of Civil Engineers (Hkig 2010).

For Germany, more detail was needed to break total capacity down on the 18 German nodes. For that purpose, the distribution used in the scenario framework for the network development plan 2012 (TSO 2011a) by the German TSOs was applied. They identify an allocation to DENA zones for each source of energy.

Studies such as the RE-Shaping study only take into account run-of-river generation. The data on the installed capacity of pumped storage power plants therefore was adopted from the NREAPs. However, they only provide information for the year 2020, so planned projects until 2030 had to be added. For Switzerland, Norway, Croatia and Ukraine, the data was gathered from government studies and other studies on pumped storage (Vennemann et al. 2010, BFE 2011, MZOPU 2004, SGEM 2011, Hkig 2010).

The pumped storage plants in Germany had to be allocated to the DENA zones via their postal code as there is no distribution for pumped storage power in the TSO scenario pathway mentioned above. The location of the pumped storage power plants and their installed capacities were obtained directly from the German electricity suppliers E.ON, RWE, Vattenfall and EnBW (TSO 2011a). The capacities of the plants that are not in possession of the big four suppliers were extracted from a list of power plants by the German Federal Environmental Agency (UBA 2011b). The planned capacity extensions of pumped storage power plants in Germany (TSO 2011a, Vennemann et al. 2011) were added to the present-day data.

3.3.3 Non-Renewable Energy Sources

Since the NREAPs and the RE-Shaping study do not provide any information on conventional generation, we revert to the "Trends to 2030" study by the European Commission for 2030 data on a European level.

For Germany, we opt for a higher degree of resolution and use our own power plant database. For data on non EU-members, public and private studies of the respective countries were examined.

3.3.3.1 Data for Germany

The German power plant fleet of 2030 is estimated based on existing data and future projections. See Table 8 for a visualization of the conventional estimation.

In a first step, we draw on our own fossil power plant database for Germany in 2011, which is based on publications by the Bundesnetzagentur (BNetzA 2011), Platts (Platts 2011) and the original data set of ELMOD (Leuthold et al. 2011). We then remove all fossil power plants that will have reached a lifetime above 50[1] years in 2030, as well as all nuclear facilities. This leaves us with the *existing* part of the 2030 power plant fleet.

Then, we add those power plants that are sure to be built between now and 2030 (late planning, early construction and beyond). At the moment, the number of power plants that have a significant likelihood of reaching commercial operation is rather short, since the economic environment in Germany for new conventional power plants is becoming increasingly uncertain. Developers of fossil power plants are facing pressure as increasing shares of renewables decrease the full load hours of conventional plants under current market design. We rely on several publications, such as VGB 2011, BDEW 2011 and Prognos 2011 for information on projects in planning or in construction. These plants are labeled as *planned* in our calculations.

We then subtract *existing* and *planned* capacity from the 2030 projections in "Szenariorahmen für den Netzentwicklungsplan 2012" (BNetzA 2011b) published by the four German TSOs. The difference between the two represent expected, but not yet explicitly planned power plant capacity. We therefore label this part of our calculations as *anticipated*. The assignment of these *anticipated* future power plants to DENA zones is carried out according to the distribution in 2011.

2011 - planned shutdowns	MW		New/ modernized plants until 2030	MW		Target by TSOs for the year 2030	MW
Lignite	8489		Lignite	5411		Lignite	13900
Gas	15217		Gas	24883		Gas	40100
Oil	500	+	Oil	0	=	Oil	500
Pumped-Hydro	9000		Pumped-Hydro	0		Pumped-Hydro	9000
Coal	10589		Coal	10611		Coal	21200
Nuclear	0		Nuclear	0		Nuclear	0
Others	700		Others	2000		Others	2700
Sum	44495		Sum	42905		Sum	87400

Table 8: Installed Fossil Capacity in 2030

Source: Own calculation based on BNetzA 2011b.

3.3.3.2 Data for the Rest of Europe

For the rest of Europe, we draw on net generation capacity projections by the European Commission (EC 2009): Trends to 2030. The data from the reference scenario was used for the fossil solids, gas and oil. For non-EU members Switzerland, Norway and Croatia, we use data from the European Grid

[1] We increase the average power plant lifetime beyond the usual 40 years to a total of 50 years, in order to reflect the decreasing economic feasibility of greenfield projects.

study by energynautics GmbH (Tröster et al. 2011). Individual data for the Ukraine was derived from the base case of their official energy targets until 2030 (ESBS 2006). Several studies do not differentiate between the two different types of solids: hard coal and lignite. For that reason, a specific repartition between hard coal and lignite had to be been done for each individual country. These figures were derived from the share of hard coal/ lignite in the “share of fuel for gross inland consumption by fuel in 2008”, which were mostly 100 percent to either of them depending on the national resources of the country (Eurostat 2011).

3.3.4 Combined Heat & Power

Combined heat and power (CHP) or cogeneration of heat and power is an energy conversion process which generates electricity and useful heat simultaneously in one process. All thermal power plants produce a certain amount of heat during energy conversion which often is emitted unused to the environment. Cogeneration plants capture some part of the emitted heat and feed it as steam or hot water into district heating systems or industrial processes.

Combined heat and power plants may be related to four main technology types: 1) Backpressure power plants use steam turbines for electricity generation which provide overheated exhaust steam with high pressure. Backpressure based CHP facilities are by far the most common, as they combine relatively low capital costs with a high total efficiency (UNEP 2006). A limiting precondition is their need for a constant and high demand of heat, as otherwise the highly energetic exhaust steam needs to be condensed which implicates a low efficiency. 2) Extraction condensing power plants utilize condensing turbines and extract steam before it is fully expanded. They are independent from exhaust steam demand and thus are adapted for fluctuating heat demand profiles. During useful heat production, their overall efficiency is lower compared to backpressure based CHP plants. 3) Gas turbine power plants equipped with heat recovery steam generators can provide overheated steam for useful heat extraction, electricity generation (combined cycle power plants) or a combination of both. 4) Reciprocating or combustion engine power plants are mainly employed for decentralized heat production and can provide useful heat and electricity at low scales with low space requirement and relatively high overall efficiency. Another CHP technology currently developed and with high potential are fuel cells, as they can provide both heat and electricity with high efficiency, but so far with high capital costs and problems with providing fuels. The primary energy source for these CHP technologies can be a wide range of fuels, including biomass and fossil fuels, as well as geothermal, solar or nuclear energy.

Electricity production with combined heat and power in the EU27 amounted in 2006 to 366 TWh, i.e. eleven percent of the total electricity generation and is considered a proven tool to meet the EU energy efficiency and saving’s targets (EC 2008). Of the 100 GW installed CHP capacity in EU27, 22 GW are located in Germany with a yearly electricity generation of 80 TWh (Eurostat 2010). The German share of 12.5 percent electricity produced through CHP (2008) is being promoted by the German government to reach 25 percent in 2020 (GT&I 2009). In 2008, the German fuel input into CHP amounted to 1200.8 PJ and allocates to fuel type as shown in the table below.

	CHP Fuels 2008 [PJ]	CHP Fuels 2008 [%]	CHP Fuels 2030 [%]	"Must Run CHP" Winter 2030 [GW]
Lignite & Hard Coal	325.41	27.10	22.00	3.30
Gas	623.11	51.90	61.00	9.15
Oil	56.44	4.70	0.00	0.00
Renewables	80.45	6.70	13.00	1.95
Other Fuels	116.48	9.70	4.00	0.60

Table 9: Input Share of CHP Fuels & Must Run CHP

Source: Eurostat 2010, own assumptions.

In electricity generation modeling, a certain part of CHP plants requires special attention. Some plants show "must run" characteristics, i.e. they generate electricity by necessity whenever they are required to produce heat. For power plants for public supply this is especially the case in winter, when district heating systems need to be supplied. In our analysis we estimated a maximum installed capacity of 15 GW for must run CHP plants in 2030. This maximum is reached in winter, in autumn and spring it amounts to ten GW and in summer to five GW. These assumptions go in line with similar studies (e.g. Ffe 2009) and represent 42 percent of the overall CHP capacity if an installed capacity of 35.7 GW for the year 2030 is taken as basis (Leitstudie 2010). In order to allocate CHP capacity to fuel type, a prognosis on the share of fuel types of CHP has been made and is shown in Table 9. The prognosis takes into account long-term trends of CHP development (UBA 2011a) and displays a significant growth of the gas and renewables share, a considerable decline in coal and oil utilization and a sharp decline of the share of other fuels, mainly due to the phase-out of nuclear energy. The share of must run CHP Renewables is not separately modeled, as Renewables are generally considered as must run facilities.

3.4 Electricity Generation Costs

Generation Costs, particularly short term variable costs and fuel costs, play a crucial part in the model since they determine the sequence in which power plants join the electricity mix: the merit order dispatches power plants based on their marginal cost of electricity generation. Most often, marginal generation costs reflect the fuel costs of the power plant. This section outlines the choices for fuel prices, variable costs of certain technologies and power plant efficiencies.

3.4.1 Renewable Technologies

Fluctuating renewable energies such as wind, photovoltaic have no fuel costs at all, and are therefore always in merit if not internalizing external costs. Deep geothermal energy does not incur any fuel cost either, but its variable operation and maintenance costs, averaging 1.5 €/MWh (ACIL Tasman 2008), reflect the marginal generation costs. Biomass plants in Europe are able to run on a variety of fuels, and we aggregate their costs at 50 €/MWh (BMU 2010).

Technology	€/MWh_{el}
Wind	0.0
Solar	0.0
Biomass	50.0
Wave/Tidal	0.0
Geothermal	1.5

Table 10: Marginal Generation Costs of Renewable Energies

Source: Own depiction based on ACIL Tasman 2008, BMU 2010.

3.4.2 Conventional Power Plants

Since lignite is not sold on the open market, its price is reflected by its extraction costs. According to several studies, lignite has extraction costs of about 0.83 EUR/GJ, which are not subject to major changes in the next 20 years. An additional 30 €/kW of constant operating costs increase the marginal generation costs by 7.19 EUR/MWh, if assuming a lignite power plant load factor of 70 percent (ÖkoInstitut 2010). The efficiency of lignite power plants reaches 49 percent by 2030 (BMU 2010).

Hard coal prices in Europe are expected to rise to 4.7 EUR/GJ by 2030 (including operating costs). This amounts to marginal generation costs of 33.24 EUR/MWh, assuming an efficiency of 50.9 percent (BMU 2010). Oil and gas prices reach 13 and 10.3 EUR/GJ respectively, including operating costs and assuming efficiency values of 43 and 62 percent (BMU 2010). The external costs of fossil fuels are reflected through the 2030 CO_2 price of the EU Emission Trading Scheme, which we set at 50 €/t_{CO2}.

Nuclear energy is characterized by low efficiency (33 percent) and even lower fuel costs (when not internalizing the full extent of external cost). Marginal costs of nuclear power plants in 2030 are less than 10 €/MWh_{el} (EWI / Prognos / GWS 2010).

	Fuel Price 2030	Fuel Price 2030	Efficiency [%]	Operating Costs	MCoE-2030
Lignite	0.83	2.99	49.00	30 €/kW	13.29
Hard Coal	4.70	16.92	50.90	-	33.24
Gas	10.30	37.08	62.00	-	59.81
Oil	13.00	46.80	43.00	-	108.84
Uranium	0.91	3.28	33.00	-	9.93

Table 11: Costs for Fossil-based Energy Generation

Source: Own depiction based on BMU 2011, ÖkoInstitut 2010, EWI / Prognos / GWS 2010.

	MCoE-2030 [€/MWh_{el}]	CO_2-Emission [t/MWh_{el}]	CO_2 Price / External Costs	MCoE + CO_2 [€/MWh_{el}]
Lignite	13.29	0.77	50 €	51.69
Hard Coal	33.24	0.61	50 €	63.69
Gas	59.81	0.30	50 €	74.91
Oil	108.84	0.68	50 €	142.84
Uranium	9.93	-	-	9.93

Table 12: Costs for Fossil-Based Energy Generation Including External Costs

Source: Own depiction based on BMU 2011, ÖkoInstitut 2010a, EWI / Prognos / GWS 2010, Greenpeace 2011.

3.4.3 Ramping Costs & Time

Two factors often not considered in related studies are ramping cost and ramping time, as they increase the effort to model a cost-minimizing allocation of electricity production. However, conventional energy generation plants, especially base-load plants, do require considerable lengths and amounts of energy to start up. With more fluctuating renewable energy feed in the electricity grid, the need for power plants with the ability for flexible load changes and a fast start-up and shutdown is growing. Therefore, ramping cost and ramping time need to be included in the analysis for more realistic modeling outcomes.

Main restrictions for ramping times are the maximum temperature and pressure differences within thick-walled components. Also susceptible and complex components need special attention and require specific limitations for temperature and pressure changes. For example boilers for steam generation in coal fired power plants hold a maximum ramp rate of seven Kelvin for temperature and 0.05 Mpa (Megapascal) for pressure per minute (Klemm 2007). Typical start-up processes in coal fired power plants begin with filling the boiler with feed water and opening the bypass valves, followed by the ignition of start-up burners fuelled with oil or gas (Strauß 2009). Step by step coal burners are started and slowly increase temperature and pressure in the boiler units. With a steam temperature of around 350°C the bypass valves are closed and steam is fed to the turbine. After synchronizing turbine and generator speed, main steam pressure and temperature is raised further and power generation reaches full capacity. In other steam based power plants start-up processes take similar routes with regard to their specific requirements (Henkel et al. 2008). Hydroelectric power plants and gas turbine power plants without attached steam cycles have far less complicated start-up procedures and can provide power with high load gradients and at a minimum of start-up costs and lengths.

The sequence and requirement of start-up processes differs according to the duration the plant has been shut down. For non operating lengths greater than 50 hours it is referred to as cold, between 8 and 50 hours as warm and less than 8 hours as hot start (VDE 2009). Hot starts are characteristic for power plants run in a daily cycling mode which are shut down over night and take up generation in the morning. Their start-up time is considerably reduced as their boiler and turbine units still hold high temperatures, in coal fired plants from 370°C to 480°C (Lefton 2006). Table 13 below shows typical values for start-up durations of conventional energy generation facilities. For hot starts, data is also given as a load gradient “Maximum Ramp Up”, measured in percent of nominal power possible to ramp up during one hour. The ramping up constraints of our modeling analysis are based on these values.

		Start-Up Time [h]		**Maximum Ramp Up [% P/h]**
	cold	warm	hot	hot
Lignite	10.0	5.0	2.0	50.00
Hard Coal	6.0	4.0	1.5	66.67
Gas (CC)	5.0	3.0	1.0	100.00
Oil	5.0	3.0	1.0	100.00
Uranium	50.0	25.0	3.0	33.33

Table 13: Start-Up Time of Conventional Power Plants

Source: Own Assumptions based on Grimm2007, Swider 2006, Traber et al. 2011, Klemm 2007, Ludwig et al.2010.

Ramping costs can be split in three main fractions: 1) costs of start-up fuels, auxiliary electricity, chemicals and additional manpower required for unit start-up, 2) depreciation of the components exposed to wearing along with higher maintenance and overhaul capital expenditures and 3) lost profits due to lower efficiency of power plants when ramping (Lefton 2006). Ramping time is closely connected with ramping cost, as both mainly arise for the same reason of material limitations. As mentioned, the demand for flexible power plants is rising. Increasingly, big steam-based power plants are run in shorter cycles of start-up and shutdown and move their operation mode from base load to medium and peak load. As this involves higher amounts of money spend on ramping, measures to decrease ramping costs gain significance. These measures can include the retrofitting of supporting systems, like a high pressure steam bypass, or new components with thinner walls and better alloys. Also a good coordination of the different start-up processes, for example through increased automation, or the extraction of steam from nearby electricity generation units are options to decrease ramping cost and time (Boucher 2011). While many measures lower start-up costs and length at the same time, there are limits when increased depreciation costs exceed additional savings from further shortened ramping lengths.

The following table lists ramping costs for conventional energy generation technologies. Fuel price, start-up fuel requirement and start-up depreciation are the main parameters to estimate ramping costs. Values for “Start-Up Fuel” account for other start-up fuels and auxiliary electricity, but without regard to future trends in price correlation. Further costs, e.g. due to increased maintenance or reduced efficiency, are not considered but to some extend offset with technology development leading to reduced wearing. Marginal costs of electricity and carbon dioxide “MCoE + CO_2” base on predicted fuel prices of the year 2030 from a study of the German Energy Agency (DENA II2010). Please see chapter 3.4.2 for a more detailed depiction of fuel prices. Start-up fuel requirement and start-up depreciation are factors strongly depending on each facility's specific technology and start-up procedure. Newer plants often involve lower costs for start-up, as they are designed for a more frequent cycling mode. The column "Start-Up Cost" lists complete costs for a cold start, mainly due to revisions or long-term shutdowns. These costs include marginal costs of electricity and carbon dioxide, which need to be subtracted in order to obtain costs for starting up additional to the marginal generation costs. For analyzing daily cycling processes, costs for a hot start are relevant. They amount to approximately one third of the additional costs for a cold start (Klemm 2007) and are listed in the column "Ramping Cost".

	MCoE + CO_2 [€/MWh_{th}]	Start-Up Fuel [MWh_{th}/MW]	Start-Up Depreciation [€/MW]	Start-Up Cost [€/MW]	Ramping Cost [€/MW]
Lignite	25.33	6.20	3.00	160.03	35.75
Hard Coal	32.42	6.20	5.00	205.99	46.96
Gas (CC)	46.44	3.50	10.00	172.55	32.22
Oil	61.42	3.50	5.00	219.97	25.45
Uranium	29.35	16.70	1.70	491.79	132.94

Table 14: Ramping Cost of Conventional Power Plants

Source: Own Calculations based on DENA I 2005, DENA II 2010, Swider 2006 and Traber et al. 2011.

3.4.4 Investment Costs

Investment costs, also referred to as capital costs, represent the main part of fixed electricity generation costs and consist for example of costs for construction, space or main components, e.g. turbines, condensers or boilers. Costs for grid connection are included only to a small extend, due to the transmission system operators bearing these costs in Germany. Especially for offshore wind energy, connection costs can sum up to substantial amounts well in the range of billions. Variable electricity generation costs consist mainly of expenditures for operation and maintenance, fuel supply or CO_2-emission certificates and represent especially for base-load power plants the biggest share of electricity generation costs.

Table 15 lists the investment costs for main technology types of power generation. The listed values represent estimates for typical technology-specific plant capacities which real investment expenditures will undercut or exceed, depending on plant capacity and other site-specific factors. For established energy technologies we assume that lower investment costs due to research and development are offset with increasing costs for materials, labor and space and therefore costs for 2030 will be in the range of present investment costs. For upcoming renewable technologies, substantial reductions of investment costs will take place due to economies of scale, learning curves and research & development. The 2030 projection is mainly based on values derived from the World Energy Outlook 2011 by the International Energy Agency (IEA 2011) and a study on the technical and economic features of renewable electricity technologies by the Energy research Center of the Netherlands (Lako 2010).

	Investment Costs [€/kW$_{el}$]	
	2010	**2030**
Lignite	1300	1300
Hard Coal	1200	1200
Gas	400	400
Gas (CC)	700	700
Oil	400	400
Uranium	2800	2800
Wind Onshore	1100	900
Wind Offshore	2600	1500
Photovoltaic	2400	1400
CSP	5300	2800
Hydro	2500	2500
Wave & Tidal	6000	2600
Geothermal	4000	2200

Table 15: Technology-specific investment costs

Sources: Own assumptions based on IEA 2011, Lako 2010, Strauß 2009, Kaltschmitt et al. 2005, Zahoransky et al. 2010, Voß et al. 2008, BSW-Solar 2011, EWEA 2009b, IPCC 2012.

4 Scenarios

In order to understand the full implications that alternative generation and transmission constellations have on European power flows, we conduct a scenario analysis that revolves around a central reference case. The variations on the Reference Scenario explore alternative possible states of the 2030 power market: while the Strategic South Scenario mainly differs from the Reference Scenario in its generation structure, the DC Highways Scenario focuses on alternative transmission topology.

The scenarios encompass assumptions regarding demand, generation, fuel and certificate prices, grid expansions and political motives. In this section, we outline these assumptions and explain our particular choice for them.

4.1 Reference Scenario

The Reference Scenario depicts a state of the European electricity market that is probable under the condition that additional policies support the development of RE and infrastructure development in Germany and Europe.

In the Reference Scenario, no significant changes to current climate and energy policies are made over the course of the next 20 years. The phase-out of nuclear energy in Germany, as appointed by a recent amendment to the Nuclear Energy Law (AtG 2011), will see the last nuclear power utility exit the grid in the year 2022. Newly constructed fossil-based power plants are assumed to be built at the same locations where old ones have been closed.

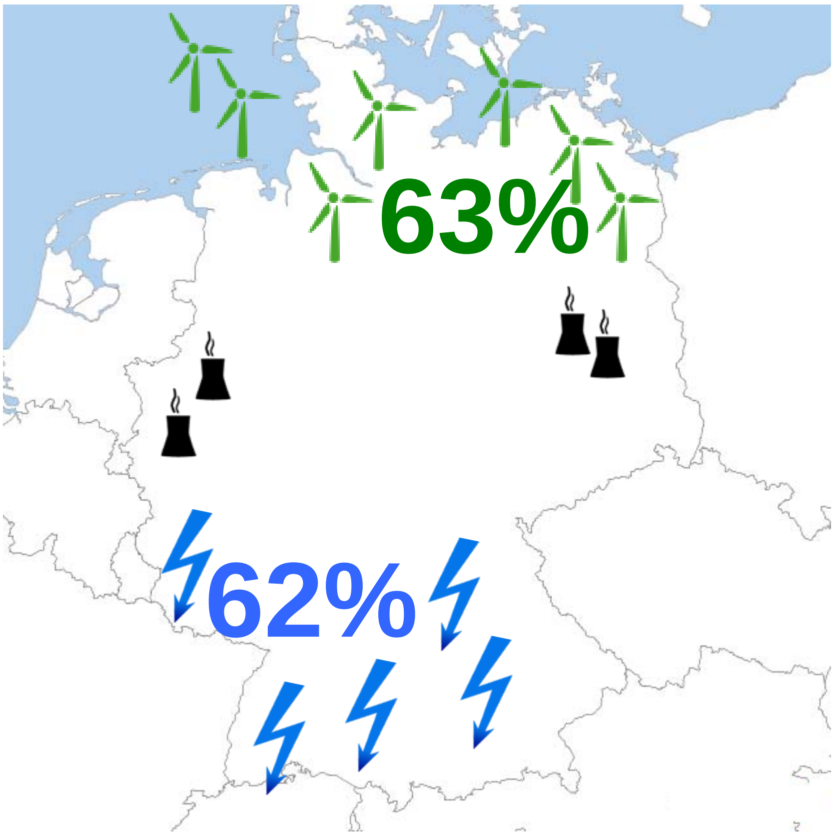

Figure 11: Reference Scenario Distribution of Load and RE Generation

Source: Own depiction.

The defining characteristic of the Reference Scenario is the strong concentration of renewable energy in the North of Germany: Niedersachsen, Schleswig Holstein, Mecklenburg Vorpommern and Brandenburg account for approximately two thirds (63 percent) of total generation. In particular, offshore installations in the North and Baltic Sea, totaling 27 GW by 2030 in the scenario, will contribute significantly to domestic generation in times of high wind. Meanwhile, the bulk of electrical load with 62 percent is located in the Western and Southern parts of Germany, noted for their dense population and extensive industry.

Even today, limited transmission capacities tend to prevent the full distribution of Northern renewable power when the wind blows hard over the North. Therefore we expect even more significant congestion from our model, as the penetration of offshore wind reaches considerable size.

4.2 Strategic South Scenario

The reference case shows a need for broad transmission expansion plans from the generation centers in Northern Germany to the centers of high demand in the South and West. Not only do these plans come at significant cost, they are also being met by significant resistance from the affected population.

The Strategic South Scenario investigates an alternative to the expansion of transmission networks on a North to South axis. The intention behind the scenario is the following: can the strategic placement of conventional power plants close to load centers, as well as an equal distribution of renewables between North and South substitute the construction of transmission?

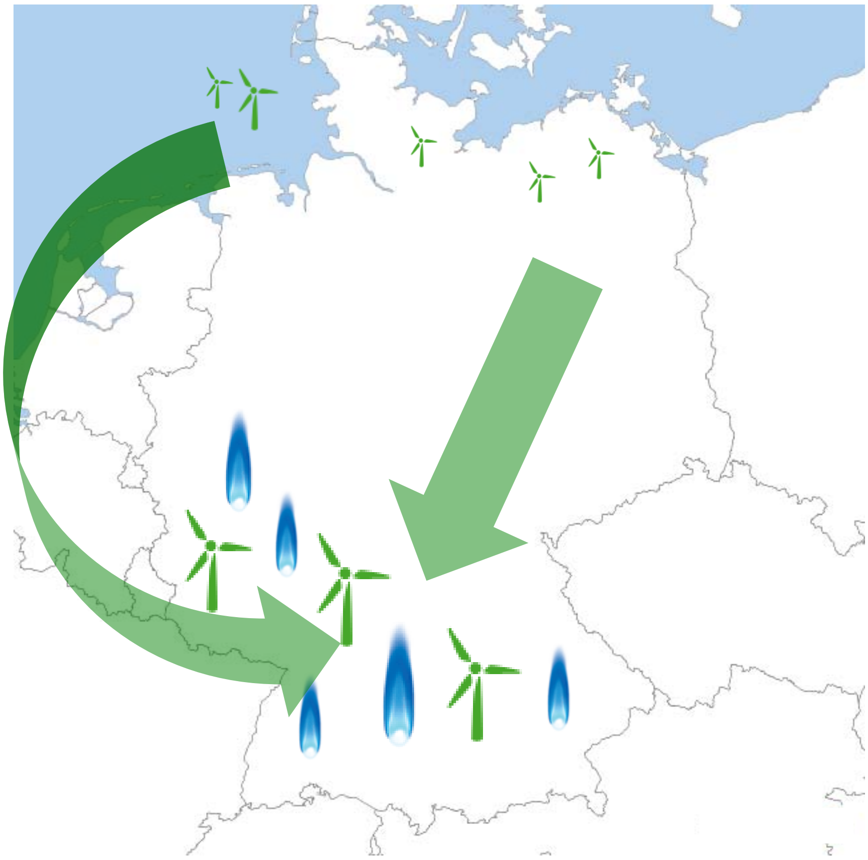

Figure 12: Strategic South Scenario Changes

Source: Own depiction.

The Strategic South Scenario consists of two major changes compared to the Reference Scenario:

First, while in the Reference Scenario new conventional power plants are built on the location of old power plants exiting the grid, they are now, as the name of the scenario indicates, being placed strategically along the metropolitan and industrialized areas of West and Southwest Germany. Especially the flexibility of additional gas turbines allows them to serve as back-up capacity for peak demand hours.

Second, there is a reallocation of renewable capacity from Northern Germany to the centers of high demand. The reduction of offshore wind in the North allows us to increase other renewable technologies (such as PV and onshore wind) in the Southwest without affecting the total renewable to conventional generation ratio. We reduce offshore wind in the Strategic South Scenario by nearly 19 GW and shift half of onshore and PV from the North to the South. See Figure 13 for a comparison of wind capacity in the Reference and Strategic South Scenarios.

The changes that we undertake occur well within the economic potential of the states. With regard to photovoltaics, the potential is 65 GW in total for Germany according to the BMU (Leitstudie 2010). For onshore wind energy, the potential was adopted from a study published by the German Association of Wind Energy (BWE 2011). The study seeks to prove that an extra 2 % of the area of Germany can be used for the expansion of onshore wind energy. The potential is examined on a federal state basis. It was found that the 2 % aim still does not exhaust the maximum potential in Germany. The federal state sharp data was allocated to the DENA zones, so that the installed capacity of onshore wind energy did not exceed the data of the 2 % scenario. See Appendix 4 for the comparison of the potential versus the installed capacity in the Strategic South Scenario. The installed capacities of the Strategic South Scenario are far below the potential outlined in the BWE study. All in all, a total of about 25 GW onshore wind capacity and about 22 GW of photovoltaic capacity were additionally installed in the industrialized DENA zones. The new allocation of renewable energy capacity to the DENA zones can be viewed in Appendix 5.

In the following graph the generation by onshore wind energy in the Reference Scenario compared to the Strategic South scenario is depicted. It quickly becomes apparent that through the reallocation generation in the Strategic South Scenario is explicitly larger in the Dena zones of high demand (24, 25, 26, 41, 42, 72, 73, 74, 75 and 76) than in the Reference Scenario.

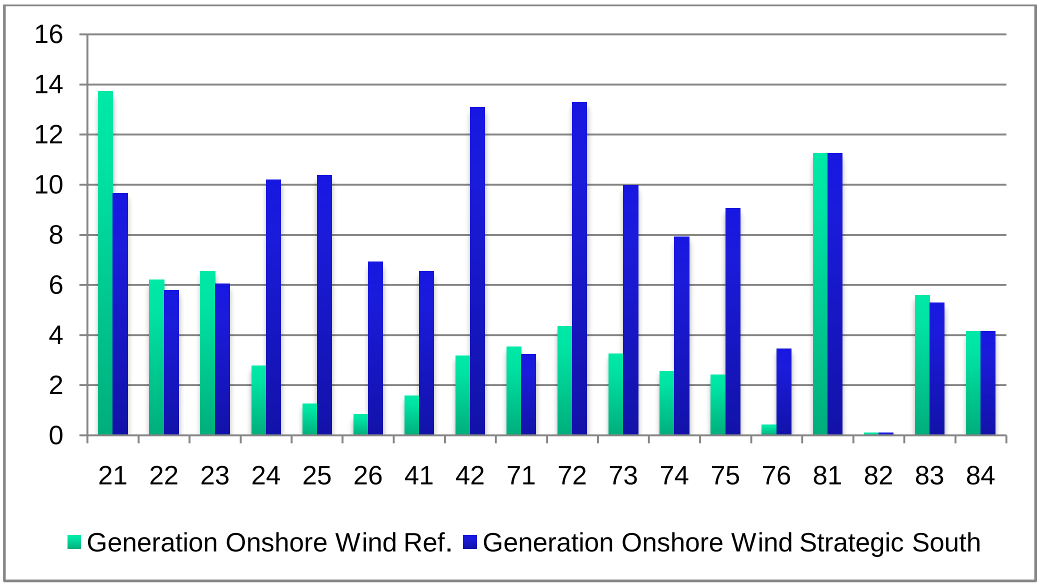

Figure 13: Onshore Wind Generation: Reference vs. Strategic South Scenario

Source: Own calculation based on [RE]Shaping 2011.

With regard to pumped storage power, the potential in Germany has already been fully exploited (Vennemann et al. 2011). Pumped storage in Germany has a potential of about 9 MW of installed capacity with a storage capacity of approximately 60 GWh. Especially in the Strategic South Scenario with its large share of fluctuating energy sources it is important to be able to make use of flexible storage capacity as a balancing instrument. Also, storage in the Alps can be of support for the German grid. For instance Austria has a potential of up to 11 GW and Switzerland up to 5 GW.

4.3 DC Highways Scenario

The third scenario variation, the DC Highways Scenario, explores the possibilities of using state-of-the-art DC technology to alleviate congestion on the high-voltage AC grid. In order to transmit the power to load centers in Central and South Germany, different transmission technologies and voltages are possible. Since coming and existing offshore wind capacity is located in the North, especially transmission capacities on the North-South-axis are considered as efficient to relieve congestion. This topic has gained some momentum in late 2011 as information on the transmission operator's comprehensive plans has reached the public (FTD 2011). As of October 2011, first insights into a DC-Overlay master plan have emerged, showing first sketches of the three DC lines' pathway (TSOs 2011). The lines span over 2100km, running North to South and East to West.

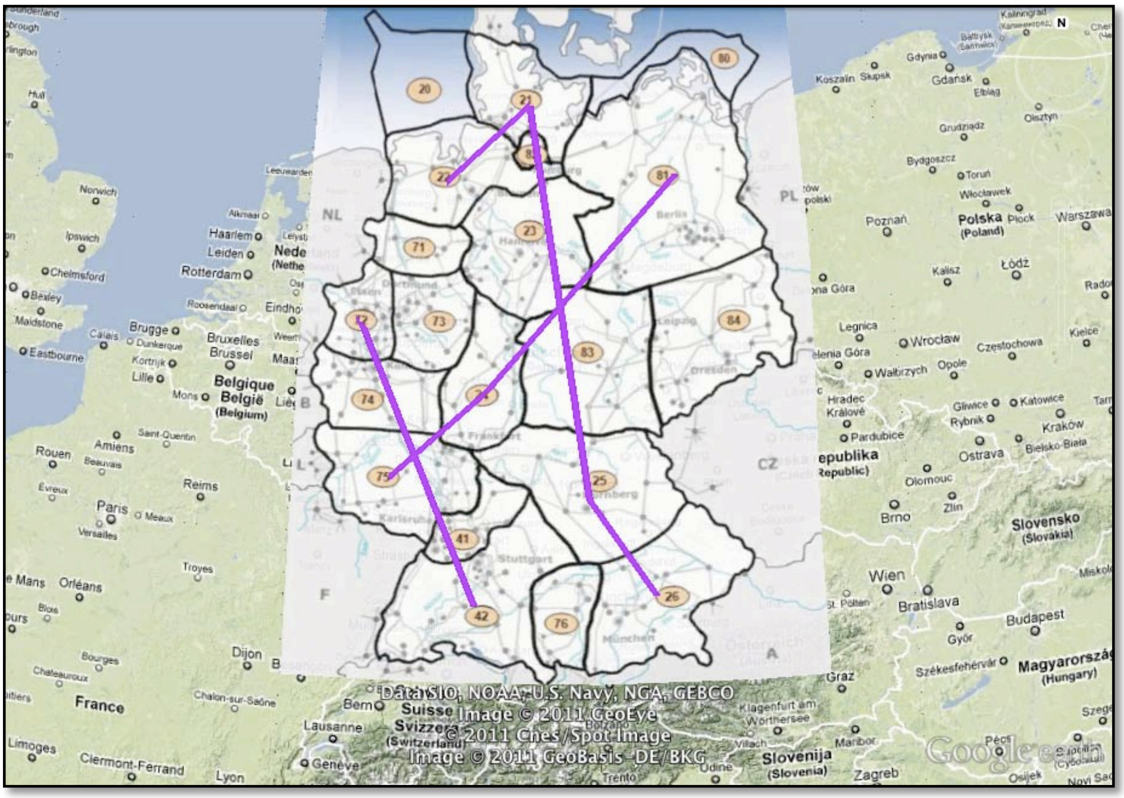

Figure 14: Proposal of DC Lines by TSOs

Source: Own depiction based on TSO 2011b.

50 Hertz, the transmission operator in Eastern Germany, has already entered the application process for the line connecting rural Brandenburg to the densely populated Rhine-Main area. Amprion and EnBW, operating in Western and Southwestern Germany, are planning a 600 km line linking the Ruhrgebiet and Stuttgart, the state capital of Baden-Württemberg. That region is facing a shortage of 5 GW of reliable generation once the last of the nuclear power plants exit the grid in 2022 (§7 AtG).

Tennet, operating on a Northwest to Southeast axis, is planning the longest of all lines, reaching over 900 km from Schleswig-Holstein to Bavaria. Its purpose will be to haul the generation of 28 GW of offshore wind across the country to a populous region that will also see substantial nuclear phase outs.

The DC Highways Scenario assumes that these projects will have reached completion and will be fully operational by 2030. The lines will start at a capacity of 1 GW with the possibility of being upgraded to 3 GW. To account for this degree of uncertainty, we model the three lines at a capacity of 2 GW.

The aim of the scenario is to investigate the effects of DC overlay lines on the existing AC grid. Will the DC highways alleviate congestion on the AC grid and ease the transfer of power from North to South? In order to verify this question, all assumptions from the Reference Scenario are left intact except for the addition of the three DC lines. This methodology provides us with the ceteris paribus effect of an overlay grid on transmission constraints in the AC grid.

5 Results

5.1 Scope of Evaluation

Instead of gathering huge amounts of data by modeling a whole year, we chose four representative weeks, one for each season of the year. To do so, we plotted renewable generation from wind and solar (by far the largest contributors to renewable generation in Germany) against weekly demand. See Figure 15 for a visualization of this information.

For spring, the choice fell on week 14, as this is a week of very low demand, a peak in wind and decent solar production. For summer, week 28 seems particularly interesting due to a significant peak in wind and very large amounts of PV. From a generation perspective, the conventional share is expected to be as small as is likely to get in 2030. The question, however, is what effects does this have on congestion?

Week 41, the autumn week, we witness unusually low wind production values for that season, while demand is rising as temperatures drop. It will be interesting to see whether the conventional power plant fleet will be able to cover the residual demand left by poor renewable performance.

Finally, week 51 shows the high demand values characteristic of German winters, as well as the year-high peak in wind production. How will the grid fare in week 51, when confronted with both large amounts of renewables and conventionals in times of significant demand?

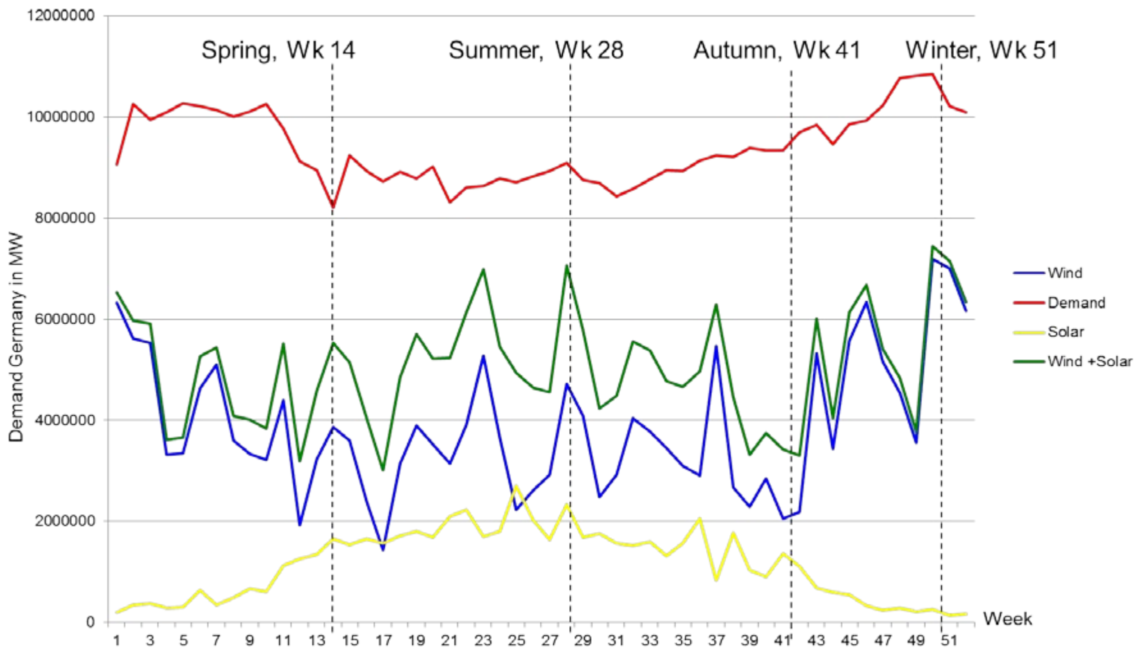

Figure 15: Weekly Sums for Demand and Renewable Generation

Source: Own depiction.

5.2 General Results

After having run the model with the three scenario variations for the four weeks chosen in section 5.1, we analyzed the renewable share of the total German generation, the congestion index and the import or export rate respectively for all four weeks.

Table 16 shows the share of renewables in each of the four weeks. It becomes apparent that the RES share of generation is lower in the Strategic South Scenario than in the Reference Scenario. The renewable share of the DC Highways Scenario and that of the Reference Scenario however only differ slightly throughout the individual weeks as the installed capacity of renewables is the same in both scenarios.

	14	28	41	51	Average
Reference Scenario	81.52 %	89.33 %	63.40 %	65.40 %	74.91 %
Strategic South Scenario	75.83 %	88.84 %	55.31 %	64.23 %	71.05 %
DC Highways Scenario	81.52 %	89.50 %	63.49 %	65.56 %	75.02 %

Table 16: RES Share for All Scenarios for Weeks 14, 28, 41 and 51

Source: Own calculation.

The results in Table 17 indicate that Germany is net importer of electricity throughout all three scenarios.

Merely in week 51, the year high wind speeds allow Germany to become a net exporter of electricity. In average the import rate is lower in the Strategic South Scenario than in the other two scenarios.

	14	28	41	51	Average
Reference Scenario	6.15 %	15.42 %	9.26 %	-2.96 %	6.97 %
Strategic South Scenario	4.00 %	6.36 %	9.10 %	-16.86 %	0.65 %
DC Highways Scenario	4.73 %	14.97 %	9.96 %	-7.29 %	5.59 %

Table 17: Import / Export Rate for All Scenarios for Weeks 14, 28, 41 and 51

Source: Own calculation.

In order to determine which one of the weeks deserved a more detailed analysis, we created a congestion chart that assigns the index of 1 to the summed up shadow variables in the Reference case (definition see equation 39 below). The results of this analysis for weeks 14, 28, 41 and 51 are depicted in Figure 16.

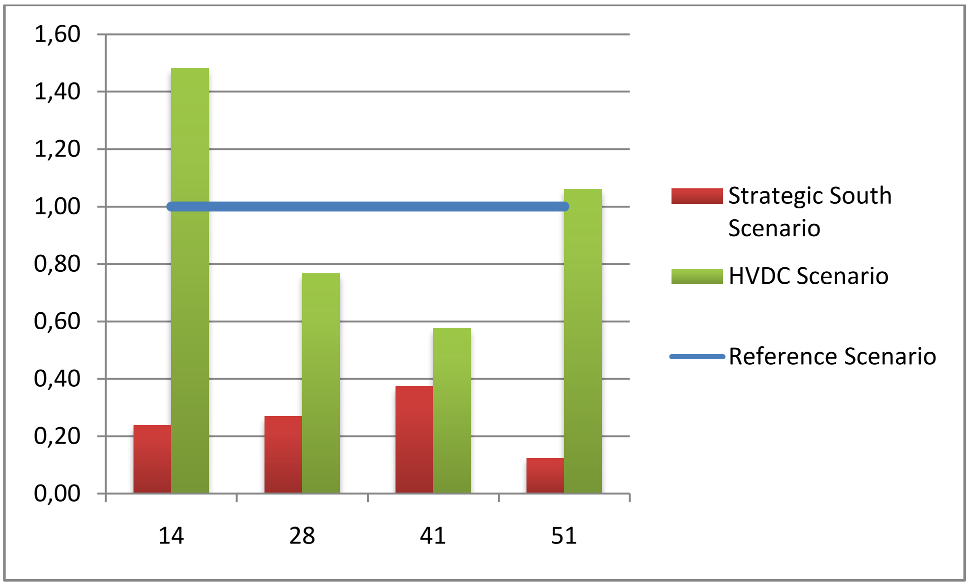

Figure 16: Congestion Index for all Weeks and all Scenarios

Source: Own depiction based on modeling results.

The chart clearly shows that the Strategic South Scenario reduces the sum of the shadow variables throughout all weeks compared to the Reference case. Its congestion index is 0.25 in average. The DC Scenario paints a different picture. It increases congestion in spring and winter, and decreases congestion in summer and autumn. The mean congestion index of the DC Scenario is 0.97, which means that on average, congestion is decreased. Since the spread between the Reference index and the Strategic South index is largest between week 51, we choose this particular week for a detailed analysis.

5.3 Detailed Results: Comparative Approach for Week 51

The following section explores the reasons behind the rise (or fall) of congestion between the scenarios by interpreting model results of power flows and generation.[2]

5.3.1 Production Status

Before entering into a detailed line-analysis, this section aims to take a closer look on the exporting status of each node. We start out with a clear pattern of electricity exporting (or importing) nodes in the Reference Scenario and see how this export (import) status evolves over the Strategic South and DC Highways Scenario. The graphical depiction of net importing and net exporting zones is the starting point for our understanding of congestion and the direction of line flows.

Figure 17 shows the import/export-balance of each node. Data has been derived from the GAMS Output by the following formula:

$$P_{exp,i,t} = -1 * (AC_{Netinpu\ t_{i,t}} + DC_{Netinpu\ t_{i},t}) \qquad (39)$$

In the result $P_{exp,i,t}$, shown in Figure 17 represents the median of net electricity generation at each node i over all 168 hours of week 51.

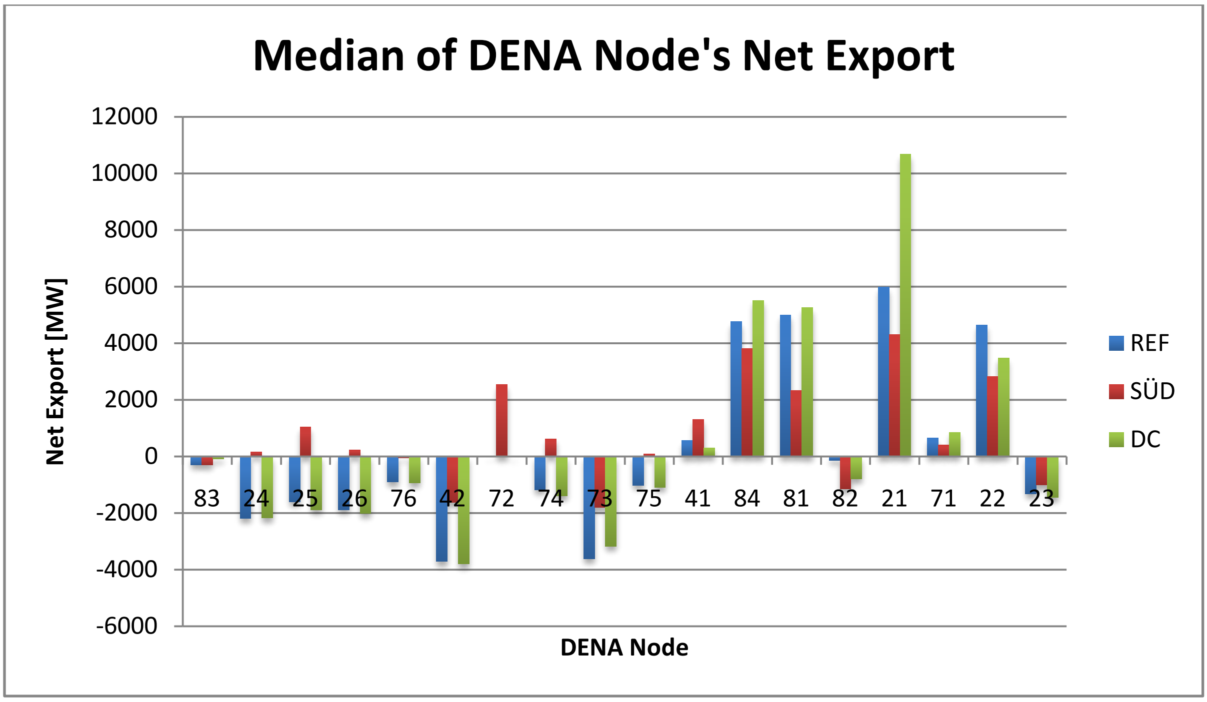

Figure 17: Net Input: Hourly Import/Export Median of German Nodes

Source: Own depiction.

[2] If you are interested to explore all results in Google Earth, including the possibility to view each lines and nodes values, please send an email to: aram@mailbox.tu-berlin.de. We will provide you with a KML file, which can be locally viewed on your desktop.

The Reference Scenario clearly shows a set of exporting nodes exclusively in the very North of Germany. Sorted in descending order by their net export amount, these are: 21, 81, 84, 22, 71, 41 and 72. For the nodes 21, 22 and 81, the reason for the high amount of exported electricity lies in the large amounts of offshore wind power in the North and Baltic Sea. As wind is under a must-run condition (marginal costs of zero) and exceeds local demand, the zones become net exporters in weeks with significant wind, such as week 51. The other four exporting nodes have a high installed capacity of onshore wind and good wind conditions over the whole year.

The major importing zones of the Reference Scenario are 73, 42, 24 and 26, all located in Germany's West and South. This is caused by the loss of large shares of installed capacity (nuclear phase-out) and a strong demand (industry and population).

For most of our 18 zones, the differences in net generation between the DC Highway and the Reference Scenario are rather negligible. However, for node 21 and 22, the difference is as significant as expected. Taking a closer look at node 21, we can observe a major increase of electricity export in the DC Highways Scenario. This increase is due to the HVDC-line linking it with the South of Germany and thus aligning its former low electricity prices with the high Southern prices.

Comparing the median of the net export of the South Scenario to the results of the Reference Scenario, an impressive change in the production structure occurs. Nearly all nodes with a net import of electrical power reduce their amount of imported electrical power significantly. At the same time all major exporters experience a drastic decline of the amount of exported electricity. Several major former importing nodes, namely nodes 25, 24, 26, 74 and 75, even turn into net exporters. However, the former main exporting nodes 21, 81, 84 and 22 continue to be main exporters and the two former main importers, nodes 42 and 73, remain net importers.

Since all nodes experiencing a major decrease in imported electricity are located in the South and West of Germany and all former main exporters experiencing this decline of net exports are located in the North of Germany, it is evident that this new allocation of imports and exports is due to the redistribution of installed capacity by the South Scenario. All in all, the South Scenario leads to a more balanced net export distribution.

Figure 18 visualizes the node's export status of all three scenarios and explicitly highlights the changes occurring in the Strategic South Scenario. Nodes that were originally net importers in the Reference Scenario and turned to net exporters in the Strategic South Scenario are highlighted in light green. Nodes that are highlighted in dark green nodes remain net exporters within all scenarios.

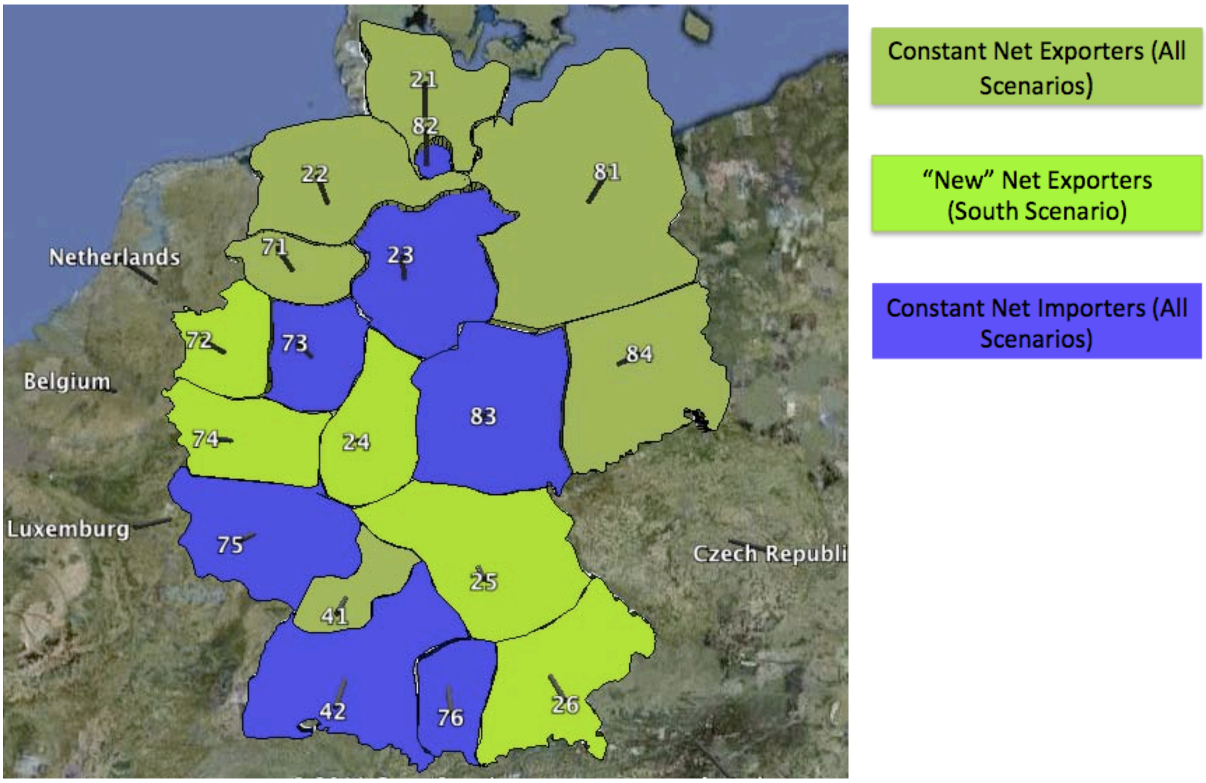

Figure 18: Net Inputs in Schematic Resolution: Net Exporting and Net Importing DENA Zones

Source: Own depiction with Google Earth.

Figure 19 and Figure 20 show the net input of electricity fed into the grid at each node in a detailed resolution. As in Figure 18, the net input is visualized by the height of each DENA zone column. A constant scaling creates a fluent transition from positive to negative values, so that the terrain's ground (0 m) represents the most negative value (import). The highest heights represent the most positive values (export). Additionally, the color filling supports the same scaling (see legend below).

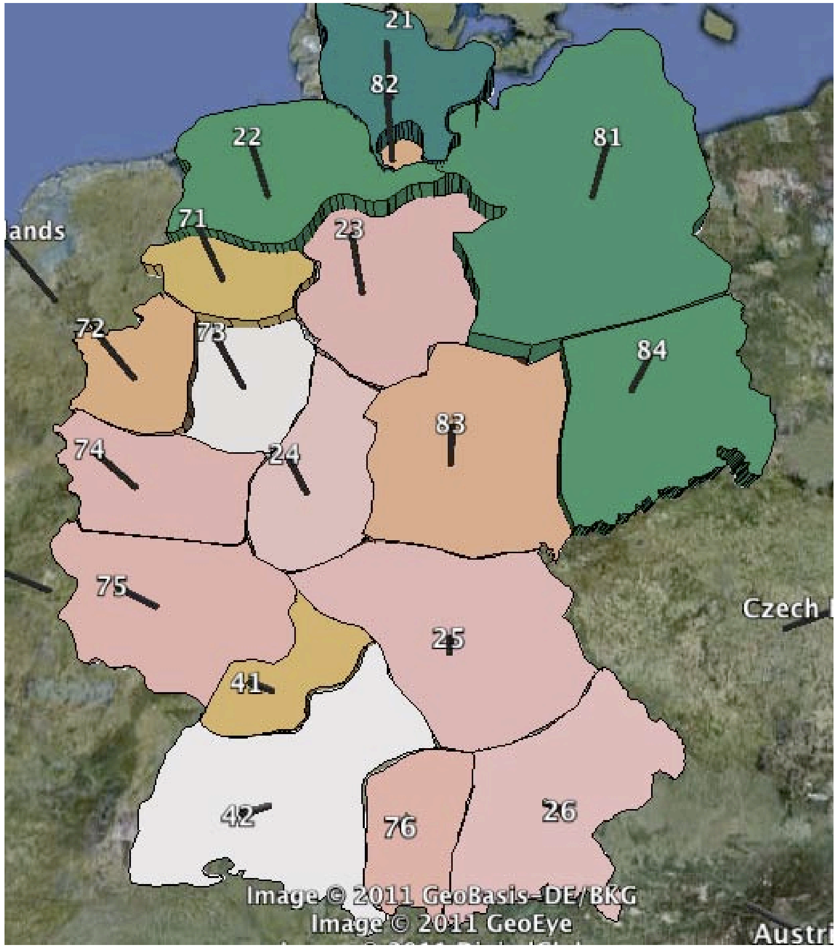

Figure 19 Weekly Median of Net Export [MW], Reference Scenario Week 51

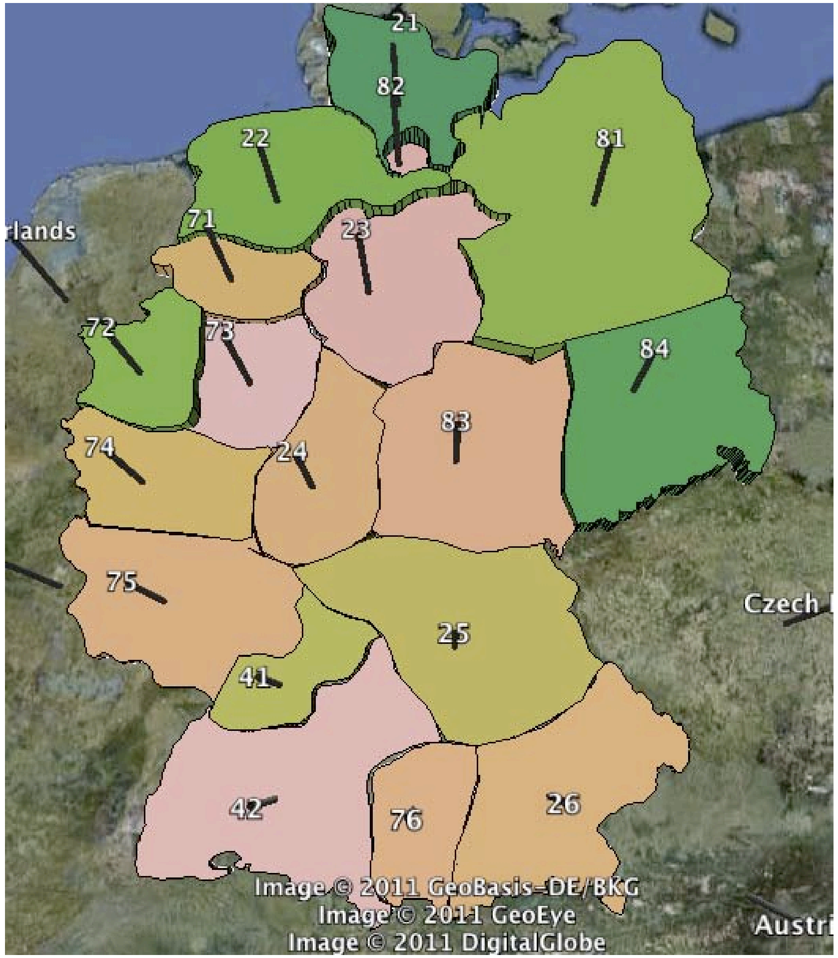

Figure 20 Weekly Median of Net Export [MW], Strategic South Scenario

5.3.2 Generation Portfolios

This section examines the generation portfolio of week 51 for the three different scenarios. First, the generation portfolio of the Reference Scenario will be considered, followed by an analysis of the generation portfolio of the Strategic South Scenario and the DC Highways Scenario.

5.3.2.1 Generation Portfolio of the Reference Scenario

Figure 21 shows the generation portfolio of week 51 in the Reference Scenario. It shows the generation mix of the specific technologies in MW for the 168 hours of one week. While the dotted black line represents the demand, the differently colored areas stand for the generation share of the respective technologies. The difference between total German demand and total German supply which is pictured in grey represents imports or exports at each hour. One can distinguish the intermittent renewables, wind and PV, the controllable renewables hydro, geothermal and biomass, as well as the conventional energy sources oil, gas, combined heat and power, hard coal, lignite and nuclear.

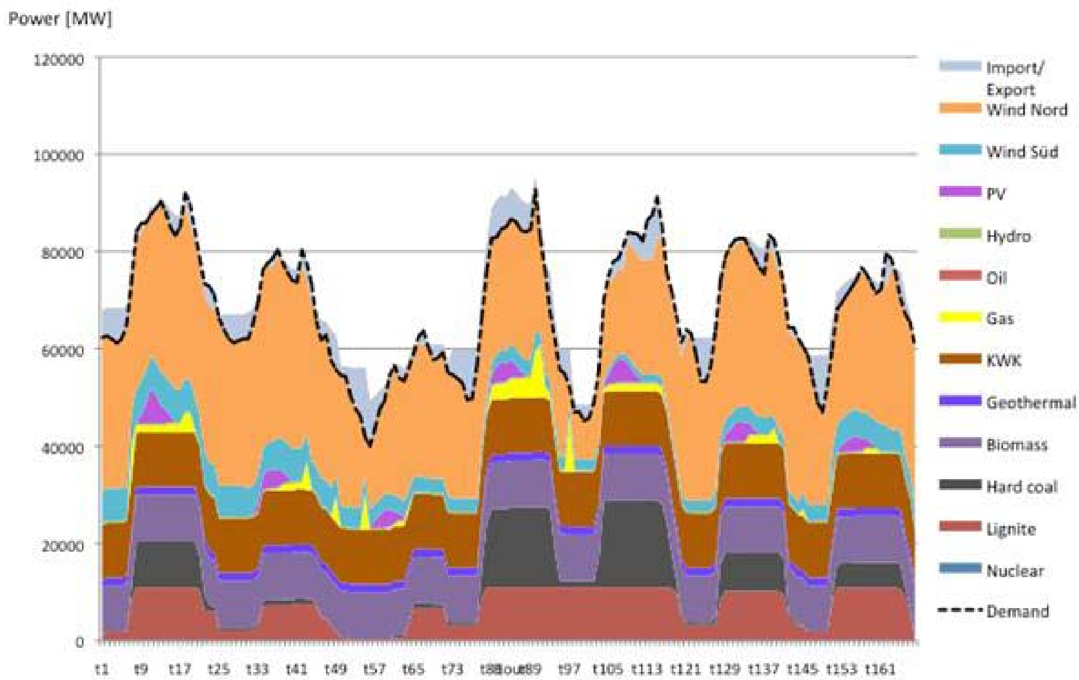

Figure 21 Generation Portfolio of Week 51 Reference Scenario

Source: Own depiction.

Concerning the generation mix, it is striking that throughout the whole week, the wind from the North of Germany, originating mainly from the offshore wind parks in the North Sea, contributes the main share of generation in Germany. There is no generation at all of oil and nuclear and generation of hydro power, wind from the South of Germany, geothermal, PV and gas only represents a small fraction of total German energy supply. Electricity generation originating from lignite, hard coal, biomass and combined heat and power account for an equal share of around 10 to 15 %.

One can observe the gas peaks triggered by the gas constraint included in our model. The generation uncertainties of intermittent renewable energy sources are evened out by flexible gas turbines that are able to ramp up in very short time intervals. One can observe that a drop of fluctuating renewables from one period to the other is partly compensated through additional gas production.

During this exemplary week, German production exceeds German consumption and import only occurs in a few peak demand hours. Overall, Germany exports around three percent of its electricity generation.

5.3.2.2 Generation Portfolio of the Strategic South Scenario

In this section, the generation portfolio of the Strategic South Scenario is analyzed. Figure 22 depicts the generation portfolio of week 51 of the Strategic South Scenario.

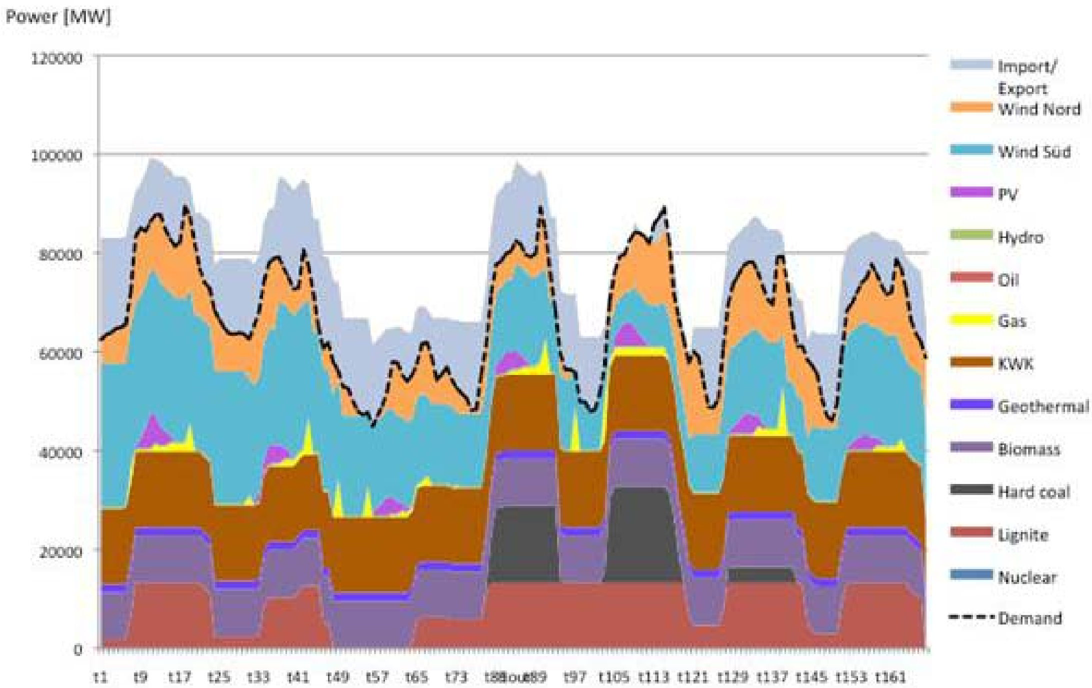

Figure 22: Generation Portfolio of Week 51 in the Strategic South Scenario

Source: Own depiction.

In the Strategic South Scenario there is a higher share of installed wind capacity in the South of Germany. Consequently the generation by wind power from Southern Germany increases from around 5 % in the Reference Scenario to more than 27 % in the Strategic South Scenario. On the other hand, one can notice the decreased generation by Northern wind power. Generation by the remaining technologies in each case only differs slightly, the share of fossils increases by around 5 %.

As well as in the Reference Scenario Germany is a net exporter of electricity at all times during week 51 with an average export rate of almost 17 % (see Table 17).

5.3.2.3 Generation Portfolio of the DC Highways Scenario

Figure 23 shows the generation portfolio of week 51 in the DC Highways Scenario. As the installed capacities in the DC Highways Scenario did not change compared to the Reference Scenario, the resulting generation portfolio is very similar. The share of electricity from renewables deviates only about 1 %, the share of fossils is slightly higher.

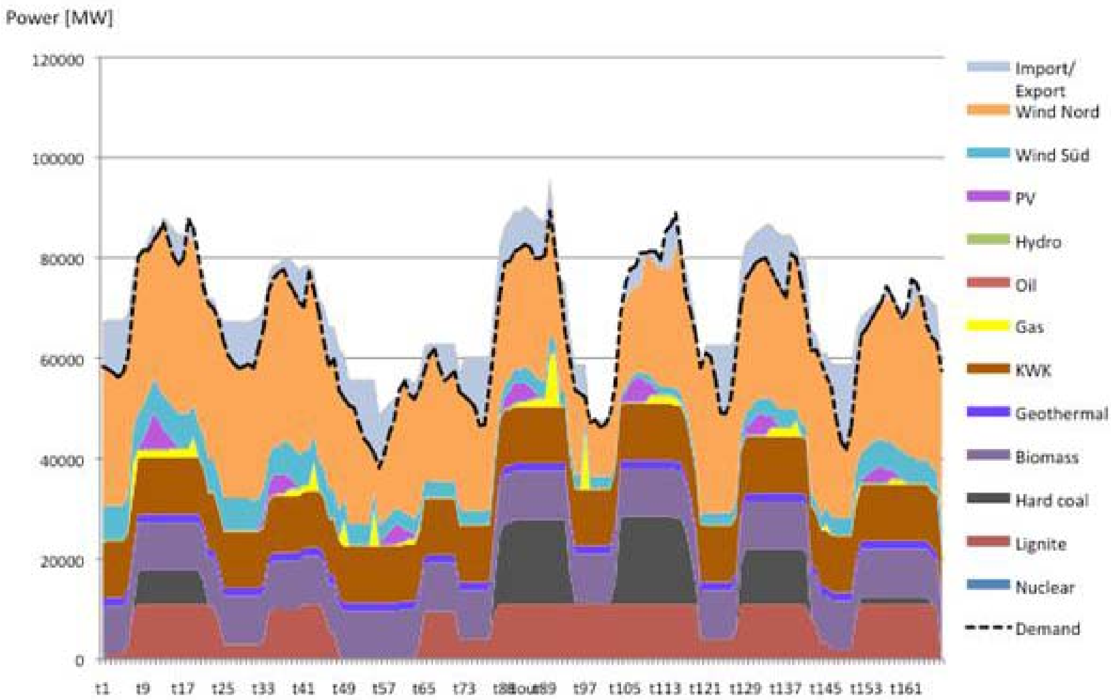

Figure 23: Generation Portfolio of Week 51 in the DC Highways Scenario

Source: Own depiction.

5.3.3 Congestion Analysis

5.3.3.1 Introduction to Congestion Analysis

In the following, Week 51 will be investigated in detail to point out changes in line congestion within the different scenarios. The DC Highways Scenario and the Strategic South Scenario will each be compared with the Reference Scenario.

Subject of investigation will be the congestion status of the German AC Grid, which is evaluated by the individual shadow variables of the lines. To create a “congestion index”, dual variables for each line are summed up over the whole 168 hours:

$$c_i = \sum_{t=1}^{168} c_{i,t} \quad (40)$$

This congestion index can be interpreted as the congestion rent in $[\frac{€}{MW*Week}]$, defining a “value” for the congestion for each line *i* over the whole week. In consequence, when comparing each scenario to the Reference Scenario, an increase of the sum represents a deterioration, a lower sum implies an improvement. For example, the reason of a lower congestion index of a line may be due to the fact that the line is not congested at all in some hours or that the value of the congestion – the price difference between the zones – may have fallen.

For a general comparison of the whole situation of the congestion of the AC grid, we define a general grid-wide congestion index c_D:

$$c_D = \sum_{i=1}^{232} c_i \quad (41)$$

- *i* Index for German AC line (232 lines in total)

In the same way, an index c_{D+} is created, that consists in a mix of AC and DC lines that connect Germany to other countries (Interconnectors).

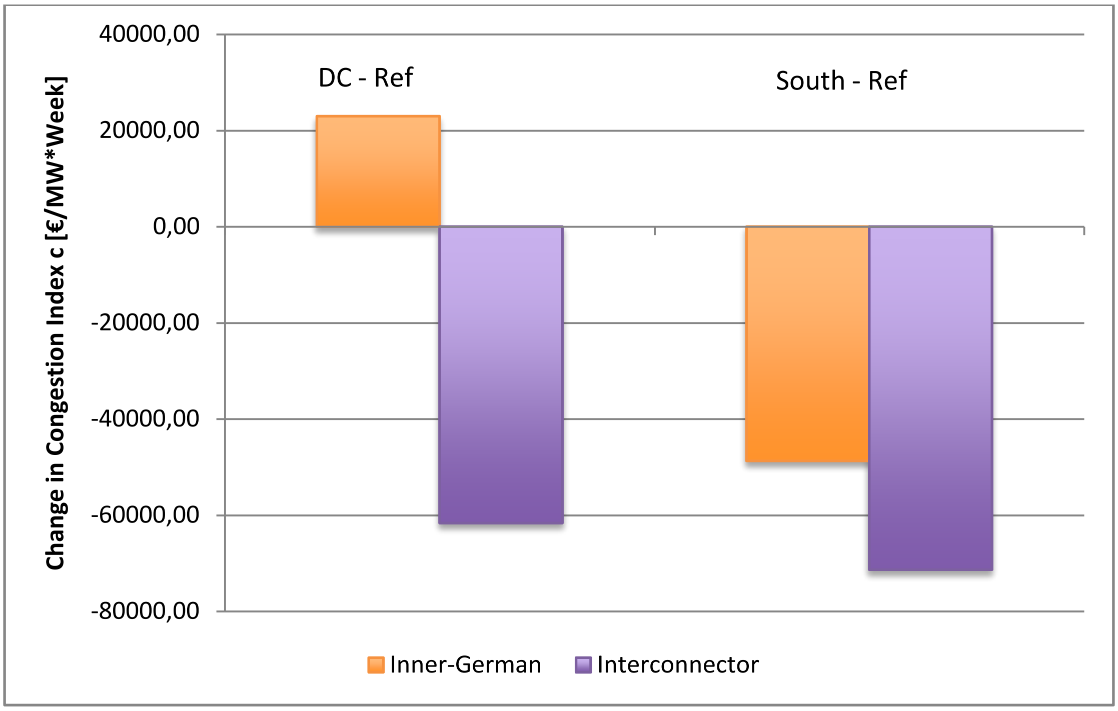

Figure 24: Total Comparison of the Grid-wide Congestion Index c_D & c_D+ - Week 51

Source: Own depiction.

Figure 24 shows the difference between the c_D values of the Reference and the two other scenarios. The orange bar represents the total congestion index c_D for all inner-German lines. The violet bar represents a total congestion index c_{D+} but only for the interconnectors. As shown in Figure 24, the congestion index falls significantly in the Strategic South Scenario for both the inner-German lines and the interconnectors. When comparing the DC Highway to the Reference Scenario there are more congestions in terms of "value" on the inner-German lines while there is an improvement for the interconnectors.

5.3.3.2 The Reference Case

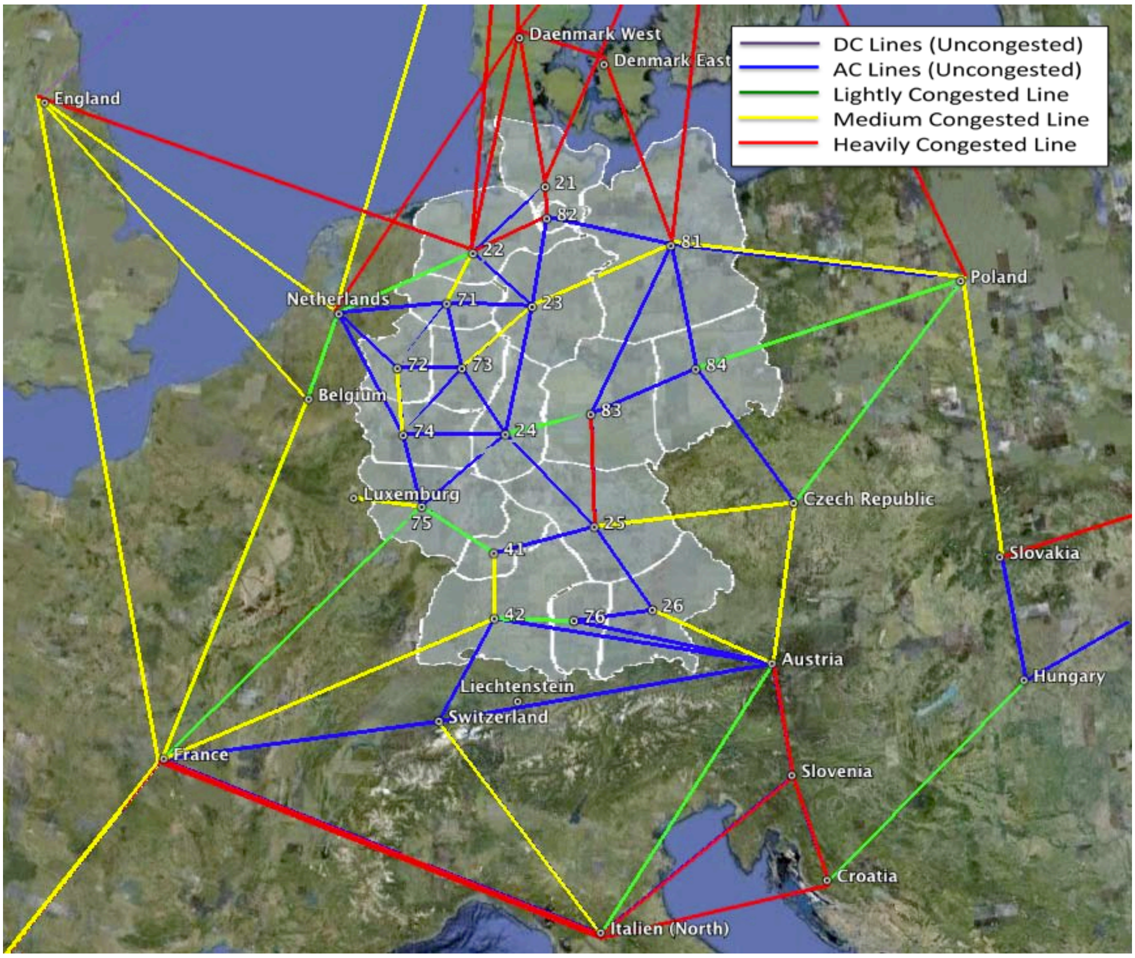

Figure 25: Reference Scenario – Congested Lines

Source: Own depiction.

Figure 25 illustrates the congestions of each line in the Reference Scenario. Red lines show a high congestion, yellow lines a medium congestion, green lines a low congestion and blue lines are not congested at all. Please find graphs with absolute values for the DC Highways Scenario and the Strategic South Scenario in the Appendix 9, 10 and 11.

As anticipated there are very high congestions on the interconnectors to Northern Europe and on the inner-German line called "Rennsteig" (line from node 25 to node 83), which is an important North-South connector. These results show that there will be a need of further grid extension in the reference case to transport all the offshore and onshore wind energy from Northern Germany to Southern Germany and to the rest of Europe.

In the following sections the Reference Scenario will be compared to the Strategic South and the DC Highways Scenario.

5.3.3.3 Reference vs. Strategic South Scenario

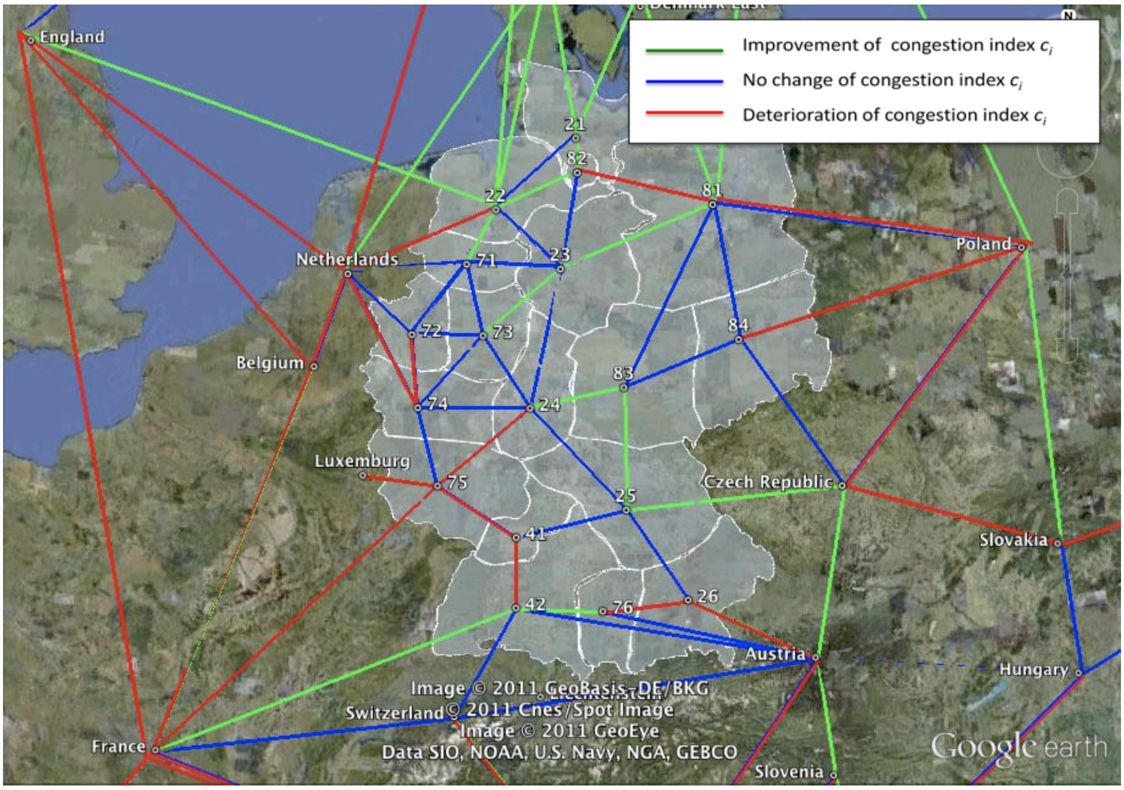

Figure 26: Changes in Congestion Index c_i: Week 51 - Reference vs. Strategic South Scenario

Source: Own depiction.

Figure 26 gives an overview of the lines with an improved congestion index in the Strategic South Scenario compared to the Reference Scenario. Green lines represent an improved (lowered) congestion index compared to the Reference Scenario. The lines coloured in blue did not change the congestion index and red lines indicate a higher congestion index. Most of the congestion in the Northwest is alleviated in the South Scenario. The red lines that appear in the South of Germany indicate that the congestion problem has not been solved, but rather exported from the North to the South. However, the newly congested lines in the South are not nearly as critically congested as the key lines in the North were. So while it appears that the South has worsened at the expense of a northern improvement, the overall effect on is definitely positive.

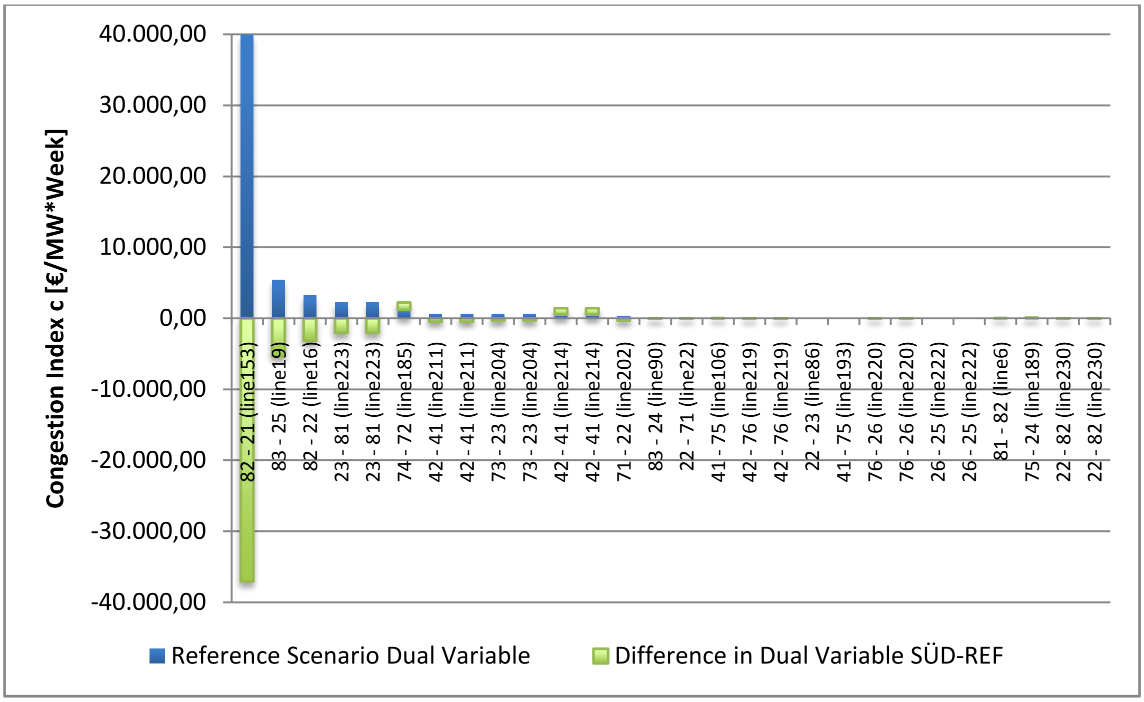

Figure 27: Inner-German Lines: Changes i Congestion Index South vs. Reference Scenario

Source: Own depiction.

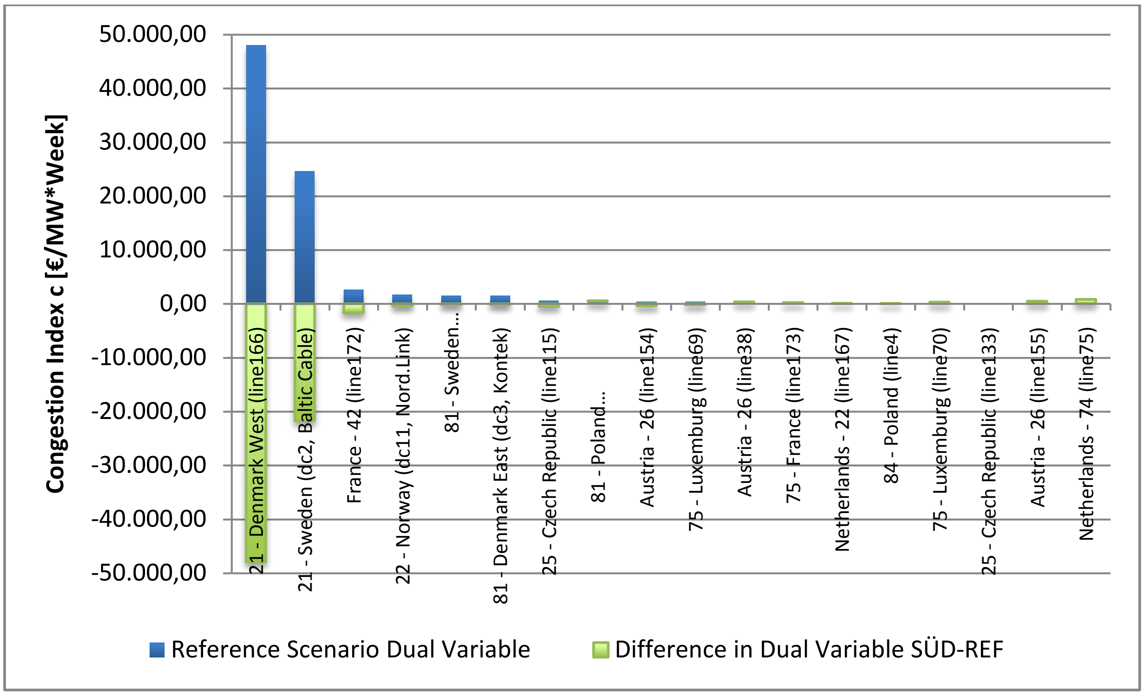

Figure 28: Interconnector Lines: Changes in Congestion Index South vs. Reference

Source: Own depiction.

For more detailed information see Appendix 7.

Figure 27 and Figure 28 show the inner-German lines and the interconnectors with their reduction and deterioration in the congestion index of the Strategic South Scenario compared to the Reference Scenario and displays the change of the congestion index for each line.

For almost every inner-German line and almost every interconnector we can observe reduced congestion indices through the Strategic South Scenario (green bars), which indicate an overall improvement of line congestion.

We can witness one significant effect: The North-South connectors and interconnectors to Northern Europe, which were congested in the Reference Scenario, show a strong improvement compared to the Strategic South Scenario. Since all other lines don't experience significant changes, we can draw the expected conclusion, that the Strategic South Scenario achieves a general reduction of line congestion.

5.3.3.4 The DC Highways Scenario Compared to the Reference Case

The changes in summed up shadow variables of week 51 between the Reference Scenario and the DC Highways Scenario are shown in Figure 29. Green lines represent an improved (lowered) congestion index compared to the Reference Scenario. The lines coloured in blue did not change the congestion index and red lines indicate a higher congestion index.

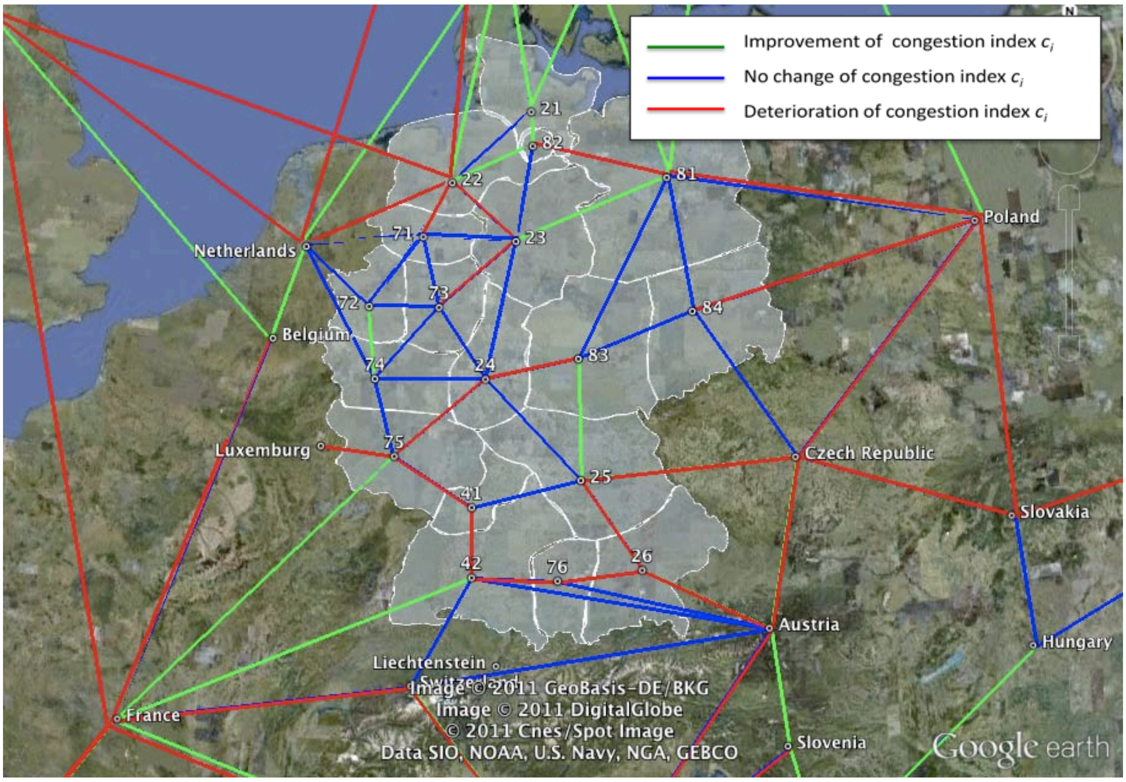

Figure 29: Changes in Congestion Index c_i: Week 51 - Reference vs. DC Highways Scenario

Source: Own depiction with Google Earth.

In addition to Figure 29 and to give an even more detailed view of the changes due to the DC Highways Scenario, Figure 30 and Figure 31 show the inner-German lines and the interconnectors with their reduction and deterioration in the congestion index of the DC Highways Scenario compared to the Reference Scenario and display the change of the congestion index for each line.

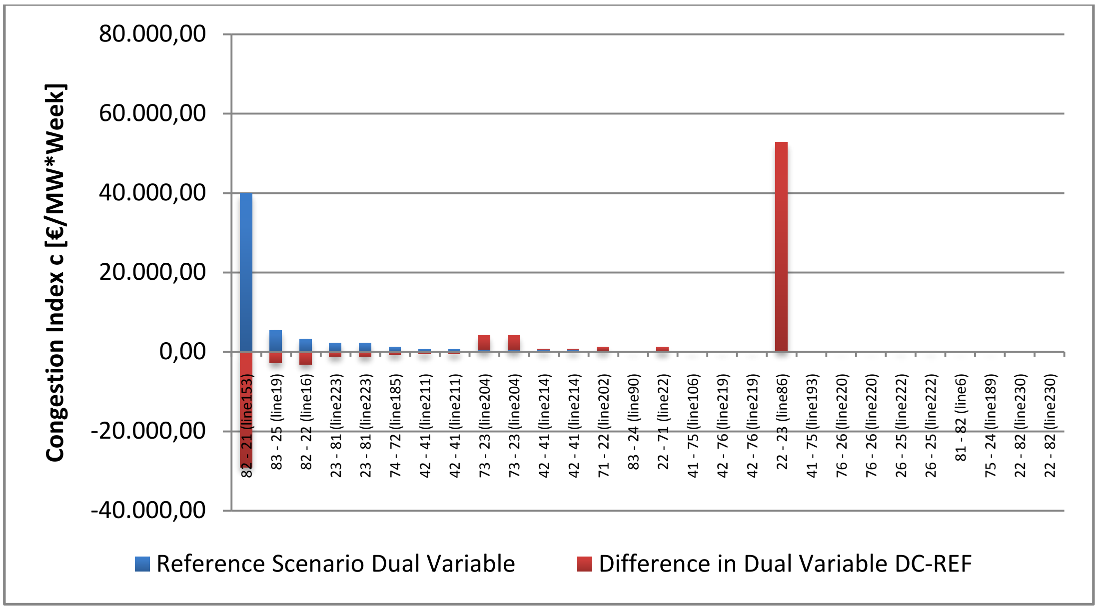

Figure 30: Inner-German Lines: Changes in Congestion Index DC Highway vs. Reference Scenario

For more detailed information see Appendix 7.

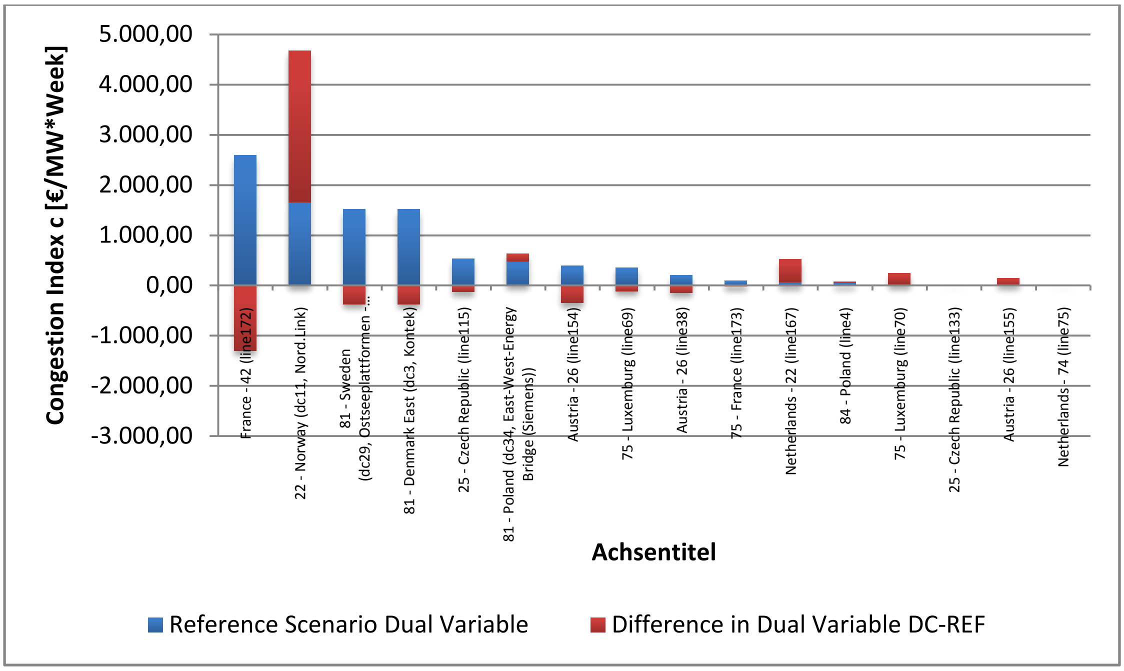

Figure 31: Interconnector Lines: Changes in Congestion Index DC vs. Reference Scenario

For more detailed information see Appendix 7.

When comparing the line congestion of the DC Highways Scenario with the Reference Scenario for week 51 there is an increase of line congestion on some lines, when installing high-voltage DC lines to the grid.

Figure 29, Figure 30 and Figure 31 show for example that the inner-German line 153 is significantly less congested, but there is a severe deterioration in line 86. Similar effects can be observed for the interconnectors, as some lines show a reduction and others a deterioration in the congestion index.

This can be explained by the following: On the one hand the DC lines provide an outflow possibility for excess capacity and thus change conditions for the better in certain regions. (For example the improvement on line 153, this goes parallel to an installed high voltage DC line.) But on the other hand, once the excess electricity arrives in the regions it was intended for, it is faced with a grid that has not been reinforced to meet the increase in supply. This leads to congestion in the ‘arrival’ zones of the DC lines, such as 22, 25, 26, 42 or 75.

5.3.3.5 Line Congestion: Dual Variables vs. Relative Number of Congested Hours

As described in the anterior section, line congestion evaluations and their graphical representation are based on a congestion index $c_{i,t}$, composed of the summed dual variables over the whole week (Equation 42). It represents the total value that the operator is able to recover in form of the so called congestion rent.[3] Alternatively it can be interpreted as the contribution of line expansion to welfare when releasing the lines capacity constraint by 1 MW. In a transferred meaning, values indicate the urgency or priority of line expansion. This method is certainly not the single one to measure the line congestion status. An important shortcoming is that it does not include any reference to the time that a line is congested. As complementary measure, we define the percentage of hours where a line is congested as follows:

$$h_l = \frac{\sum_{tc=1}^{n} \frac{LF_{l,tc}}{LF_{l,tc}}}{168} \qquad (42)$$

h	Relative number of hours, the line i runs at its maximum capacity
LF	Line flow of line i [MW]
tc	Index for times (hours) at which the line runs at maximum capacity
i	Index for lines
n	Number of hours, in which the line i runs at maximum capacity

[3] Depending on the regulative structure, the congestion rent is not always allocated to the network operator. In some regions, the rent has to be reallocated to consumers for example.

Figure 32 and Figure 33 show the results discussed in the following.

The graphs plot the relation between two congestion indicators. The x-axis depicts congestion measured as sum of shadow variables, defined as congestion indices c_D and c_{D+} in the anterior chapters (equation 41). The y-axis includes congestion measured in percentage of time. We interpret these values as the degree to which a line is actually congested. Note that the values on the y-axis do not give any hint on prioritizing line expansion projects but they are a pure measure of the observed capacity shortages. Only when brought to relation with their “value” in form of the dual variable, evaluations in that sense can be made.

A key observation for both, inner-German lines (D) and interconnectors (D+) is a fundamental linear trend between the two variables. The congestion index grows with a raising temporal congestion. This indicates a relatively stable price difference between the zones, connected by the affected lines. Interconnector lines show a significant accumulation of data points on the upper boarder of the x-axis, splitting off from the observed general linear trend. These lines show a low summed up dual variable in combination with a high temporal congestion. This can be interpreted as fully congested lines where congestion must occur between zones of exceptionally lower price differences. These lines only contribute with a low value to a welfare improvement when extending their capacity.

A further observation relates exclusively to the interconnector lines of the DC Highways Scenario. The observed linear trend in Figure 32 is substantially extended by data points from the DC Highways Scenario. As they follow the linear trend, it is most probable that, while the affected zones price differences remain relatively stable, the summed up dual variable rises due to a higher temporal congestion.

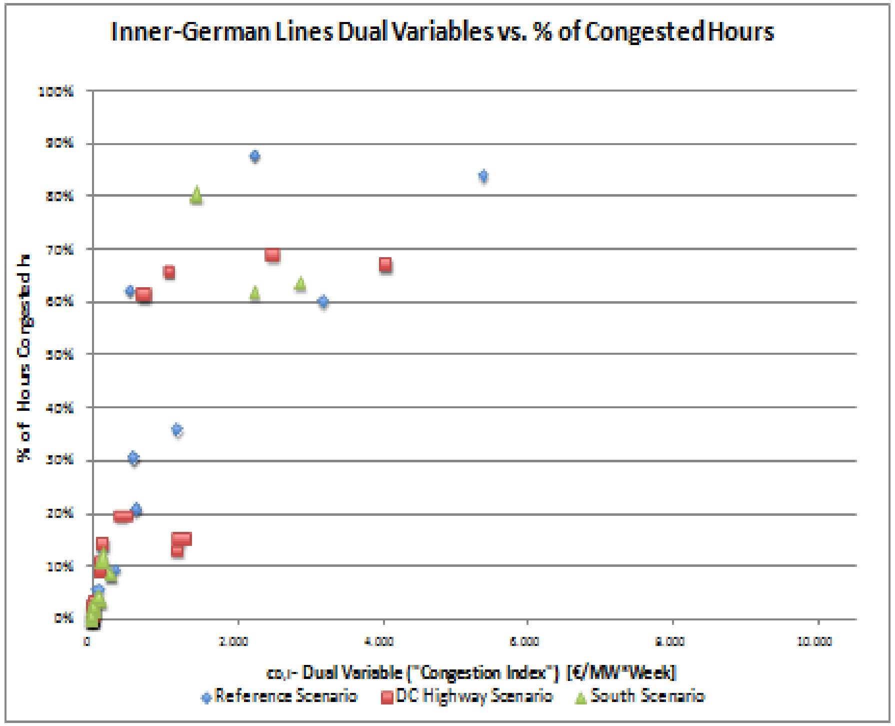

Figure 33: Inner German Lines Dual Variables vs. % of Congested Hours

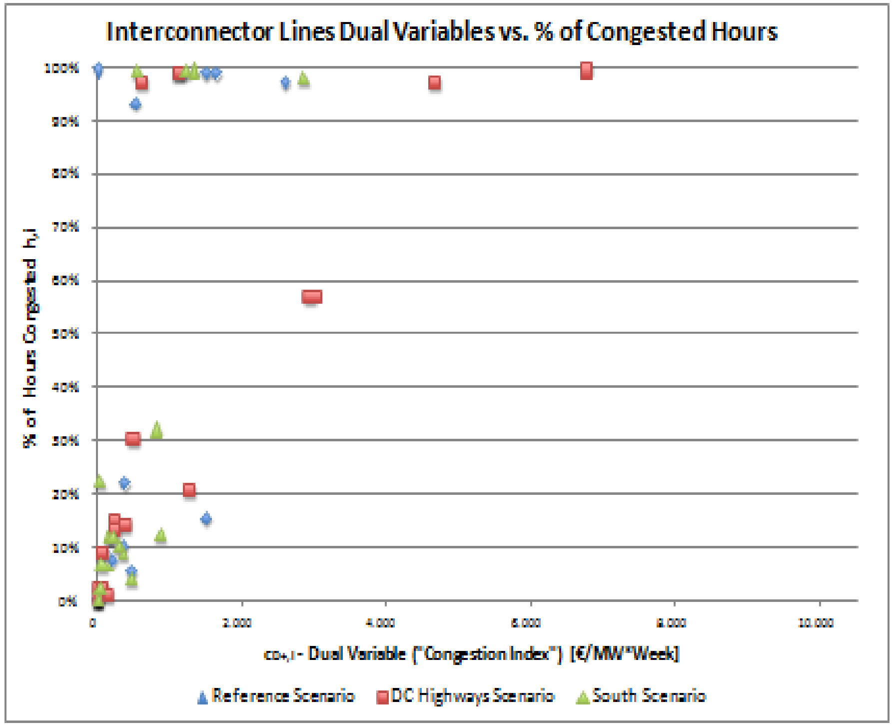

Figure 32: Interconnector Lines Dual Variables vs. % of Congested Hours

Source: Own depiction based on GAMS.

5.3.4 Implications for Welfare

The analysis of the impact on welfare contains results calculated from the model as well as specific costs incurred to build the infrastructure available in the scenarios. For the Reference Scenario no additional costs are added since this scenario is our business-as-usual-scenario. However, for the DC Highways Scenario we added costs for the expansion of the HVDC grid based on our cost assumptions in section 3.2.2. Moreover, the Strategic South Scenario has major changes in the new built installed capacity which are given by the assumptions of distribution of renewable energy capacity in Southern Germany. To answer the purpose of a welfare examination, it is obvious that also these costs should be included.

For the DC Highways Scenario, we assume expansion costs with a total amount of 9,000,000,000 €. This value includes variable grid costs and fixed costs for converter stations at nine nodes (both referring to a line capacity of 2,000 MW). Since these costs are the investment costs for a grid with an operational life of 40 years, for comparison purposes we use the annuity with an interest rate of 7 %, which is analogue to the interest rate determined by the Federal Network Agency. The calculation yields to annual costs of 675,082,250 € and to monthly costs of 54,528,760 €.

$$m = \sqrt[12]{1{,}07} \tag{43}$$

$$A = \frac{(m-1)}{1-m^{-T}} \cdot P \tag{44}$$

m	Monthly interest rate
A	Annuity
P	Present value
T	Total number of months

The modifications for the Strategic South Scenario are dependent on the changes of installed capacity. The specifications are to increase generation capacity preferably in South Germany which leads to a complete different distribution compared to the Reference case. The strategic placement of capacity in Southern Germany in the Strategic South Scenario leads to a cutback of offshore and wave and tidal capacity.

	Changes in capacity [MW]
Biomass	0
Geothermal	0
PV	2,314
Hydropower	0
Onshore Wind	28,000
Offshore Wind	- 13,941
Wave & Tidal	-3,215
Total	1,103

Table 18: Changes Caused by the Reallocation of Capacity for Each Technology

Source: Own calculation based on [RE]Shaping 2011.

Based on the investment costs for renewable energy in 3.4.4., these changes lead in total to lower costs. The reason is that the investment costs for onshore wind power plants are notably lower than the costs for offshore wind power plants (see 3.4.4). In total 833,940,619 € can be saved through the shift of capacity in the Strategic South scenario. For further comparison purposes we also use annuity but with regard to the different physical life for any technology (PV: 25 years; on- and offshore wind and wave and tidal: 20 years (IPCC 2012)) we achieve a cost reduction of 106,523,460 € p.a. and 8,604,273 € per month.

To compare the implication on the welfare we sum our four covered weeks up to a fictional month and adjust our monthly benefits and costs.

	Reference [m€]	Strategic South [m€]	DC Highway [m€]
Sum Welfare	13,422	13,545	13,537
Monthly Scenario Costs		-9	54
Net Welfare	13,422	13,553	13,483
Change in %		+ 0.98 %	+ 0.45 %

Table 19: Overview Welfare Effects

Source: Own calculation based on [RE]Shaping and ICF 2002.

The obtained results are according to our expectations. In both scenarios there is a positive effect on welfare compared to the reference case. Notably, the positive effect on welfare is higher in the Strategic South Scenario, certainly due to the costs reductions evoked by the major changes in installed capacity. However, the DC Highways Scenario also generates a higher welfare without any major changes in the capacity so key driver for the improvement is the congestion relieve through new lines. In conclusion, we observe overall positive welfare effects of HVDC lines and a strategic placement of generation capacity close to demand centers, even after deduction of infrastructure costs. Consequently, the placement of additional generation capacities into demand centers is found to be effective in reducing congestion. Likewise, HVDC lines as proposed in this study are a sensible and cost-effective approach to alleviating transmission grid congestion. However, both scenarios show that there still remains further need for grid upgrades in the ordinary AC grid. Implementing HVDC lines and placing capacities in the South are not sufficient measures to fully satisfy the grid requirements imposed by the 2030 energy system. The analysis points to the need for grid expansion beyond what is currently planned in the TYNDP context.

5.3.5 Conclusion for Week 51

The following insights emerge from the in-depth analysis of an exemplary winter week in 2030.

The renewable share in the German generation portfolio remains relatively stable in all three scenarios. It becomes apparent that in week 51, the measures taken in the scenario variations do not contribute to a better integration of renewables in terms of their share in Germany's generation portfolio.

The DC Highways Scenario brings little structural change to the national export and import patterns observed in the Reference Scenario, except in the Northern German zone 21. Here nodal prices change due to the implementation of the HVDC line. In the DC Highways Scenario the export to neighboring countries increases by ca 4 %. A key finding of the DC Highways Scenario is that inner-German congestion is not relieved by building HVDC lines across the country. As a matter of fact, HVDC lines transfer congestion from one hub to another hub. This can become a problem when the AC grid capacities around the destination hub are ill-equipped to function as “spoke” to distribute electricity to end consumers. We find this effect to be relevant in the German context. We conclude that the planning of HVDC lines is not sufficient on its own but needs to go hand in hand with a surrounding AC grid planning in destination zones.

In the Strategic South Scenario, the national import-export pattern is fundamentally shifted. First of all, the inner-German disequilibrium between Northern exporters and Southern importers tends towards a balance. Second, there is a clear shift towards more export from Germany into neighboring countries. As a matter of fact, Germany turns from a net moderate importing (around 3 % of production) in the Reference Scenario to a major net exporting country (around 17 % of production). We conclude that the strategic placement of installed capacity to demand regions brings relief to the connection between exporting and importing zones and improves the overall German export ratio. Analysis shows that congestion both, on inner-German and on interconnector lines, can be significantly reduced through appropriate allocation of generation resources. Therefore the overall welfare is improved. We conclude that grid capacity planning and generation capacity planning are intertwined problems which should ideally be coordinated in conjunction so as to reduce cost from a societal perspective.

It is shown that the duration of congestion is not always sufficient to define the priority of a certain line expansion project. Only the combined analysis of shadow variables of transmission capacity constraints and temporal congestion indicators leads to reliable statements. We find an expansion of interconnector lines to contribute more to overall welfare than compared to an expansion of inner-German lines.

6 Conclusion and Further Research

The results presented above indicate that, despite initial grid expansion efforts, the German AC/DC grid as planned in the TYNDP is not capable to integrate the amount of renewable energy in a welfare maximizing way due to remaining high line congestion. Unless transmission lines are reinforced, a welfare-optimizing dispatch of generation for Germany in a European context is unlikely to take place.

Throughout all three scenarios, we observe congestion centers in the Northwest of Germany which extend towards the South, as well as at the interconnectors between Germany and its Northern neighbors. The connections to Poland, the Czech Republic and the Netherlands are also continuously operating at capacity limit but with a lower possible contribution to welfare optimization. As a consequence, renewable electricity originating from the Northern offshore generation centers (DENA zones 21 & 22, Great Britain) do not reach German and foreign load centers at its full amount.

The modifications made in the DC Highway and Strategic South Scenario have an alleviating effect on congestion. The Strategic South Scenario shows the best results, indicating that an even distribution of generation across the country does provide an alternative to massive transmission investments. However, given national policy that is ultimately aiming for 100 percent of renewable generation in 2050, the reinforcement of existing, and the construction of new lines seems inevitable at this point.

Within the DC Highways Scenario, the AC congestion actually worsens after the introduction of the DC lines. While the North-South axis is relieved, congestion problems are transferred to destination hubs and prove that there is still a need for reinforcements of the AC lines.

This research project has modeled a representative week for every season in the year, to control for seasonal effects on renewable generation and demand. The next step is to run the model for the entire year to supplement the observations made for week 51. Other continuative goals of the project are to integrate cross-border exchange algorithms and aspects of market design, as their importance grows alongside the increase of cross border capacity. Furthermore, endogenous grid expansion algorithms can be used to iteratively optimize the grid extension.

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Legal Texts

AtG	Atomgesetz
EnLAG	Energieleitungsausbaugesetz

EnWG Energiewirtschaftsgesetz

Appendix

Appendix 1: Additions to the AC Grid of 2030

Domestic		
From	To	Type
Ganderkesee	St. Hülfe	380kV
Vieselbach	Altenfeld	380kV
Altenfeld	Redwitz	380kV
Diele	Niederrhein	380kV
Wahle	Mecklar	380kV
Hamburg	Dollern	380kV
Wehrendorf	Gütersloh	380kV
Kruckel	Dauersberg	380kV

International		
From	To	Type
Aldeadávila (ES)	Lagoaça (PT)	new 400 kV line
Guillena (ES)	Tavira (PT)	new 400 kV line
Moulaine (FR)	Aubange (BE)	new 220 kV line
Bressanone (IT)	Innsbruck (AT)	new 400 kV line
Okroglo (SI)	Udine (IT)	new 400 kV line
Lavorgo (CH)	Morbegno (IT)	new 400 kV line
Cornier (FR)	Piossasco (IT)	new 400 kV line
Hurva/Hallsberg (SE)	Barkeryd (NO)	new 400 kV line
St. Peter (AT)	Isar (DE)	new 380 kV
Krajnik (PL)	Neuenhagen (DE)	new 400 kV line
Plewiska (PL)	Eisenhüttenstadt (DE)	upgrade to 400 kV
Doetinchem (NL)	Niederrhein (DE)	new 400 kV line

Source: EnLAG & ENTSO-E 2010b.

Appendix 2: Additions to the DC Grid of 2030

International		
Name	From - To	Capacity [MW]
NORNED	Netherlands - Norway	700
Baltic Cable	21 - Sweden	600
Kontek	81 - Denmark East	600
Kontiskan 2	Denmark West - Sweden	300
Skagerrak 1+2	Denmark West - Norway	500
SwePol	Poland - Sweden	600
IFA	Great Britain - France	2000
BirtNed	Great Britain - Netherlands	1000
Norwegian Interconnector	Great Britain - Norway	1400
Storebaelt	Denmark West - Denmark East	600
Nord.Link	22 - Norway	1400
NORNED2	Netherlands - Norway	700
NordSüd1	21 - 25	2000
NordSüd2	25 - 26	2000
NordSüd3	21 - 22	2000
OstWest1	81 - 24	2000
OstWest2	24 - 75	2000
Südwest	72 - 42	2000
Skagerrak 3	Denmark West - Norway	440
Skagerrak 4	Denmark West - Norway	700
East-West-Energy Bridge (Siemens)	81 - Poland	500
COBRA	Denmark West - Netherlands	700
NEMO	Great Britain - Belgium	1000
IFA 2	Great Britain - France	1000
Gunfleet Sands1	Great Britain - Netherlands	1000
Gunfleet Sands2	Great Britain - Belgium	1000
Nordseeplattformen UK - Dollert (Emden)	Great Britain - 22	1000
Nordseeplattformen - Dänemark	22 - Denmark West	2000
SwePol 2	Poland - Sweden	600
Balltic Cable 2	21 - Sweden	600
Ostseeplattformen - Schweden	81 - Sweden	600
Ostseeplattformen - Dänemark	81 - Denmark East	600
TYNDP - Sta. Llogaia (ES) - Baixas (FR)	Spain - France	2000
TYNDP - Grande Ile (FR) Piossasco (IT)	France - Italy	1000
TYNDP - Candia (IT) - Konjsko (HR)	Croatia - Italy	1000

Source: ABB 2011, La Tene Maps & EWEA 2011, Edwards 2010.

Appendix 3: Total Renewable Installed Capacity by EU-27 for 2030

Country	Geothermal	Hydro power	PV	CSP	Wave & tidal	Onshore Wind	Offshore Wind	Biomass
Austria	587	9643	12358	0	0	4355	0	2758
Belgium	185	152	7852	0	238	2641	3655	2027
Bulgaria	275	5506	5378	0	259	3955	469	1141
Cyprus	0	0	686	498	156	986	94	36
Czech Republic	142	1427	8770	0	0	4175	0	542
Denmark	151	11	8704	0	3539	7334	7680	2941
Estonia	19	9	1200	0	654	1342	516	434
Finland	114	3267	7319	0	1048	4229	5781	4826
France	1007	28405	60994	0	15682	40244	16857	12322
Germany	1821	5660	74923	0	5216	36287	27084	10684
Greece	140	3975	9114	5065	2511	6417	1978	1124
Hungary	194	413	4893	0	0	1264	0	1853
Ireland	57	318	3566	0	2354	5129	1912	1054
Italy	1913	22098	40564	17631	3278	21365	2918	6829
Latvia	19	1820	779	0	304	925	525	381
Lithuania	38	160	1147	0	90	1786	249	643
Luxembourg	0	50	579	0	0	325	0	90
Malta	0	0	341	111	41	60	164	19
Netherlands	227	46	17571	0	670	8364	9350	2793
Poland	341	1475	28593	0	699	14003	7735	5849
Portugal	104	13190	7292	10047	7291	10888	4312	2056
Romania	415	8941	12074	0	164	4972	314	3833
Slovakia	51	2025	5140	0	0	2297	0	668
Slovenia	36	1497	2128	0	0	355	0	375
Spain	314	26348	35292	39560	9017	47018	9395	6897
Sweden	189	17490	31698	0	1841	7080	7839	3596
UK	909	1686	58639	0	36212	27931	52312	6950

Source: Own calculation based on [RE]Shaping 2011.

Appendix 4: Potential for Onshore Wind Power Expansion in Germany

Dena Zone	Potential BWE Study [MW]	Installed Capacity Strategic South Scenario [MW]
21	9000	4078
22	10600	2472
23	11400	2604
24	11200	4305
25	20500	4431
26	13667	2954
41	7667	2771
42	15333	5542
71	6200	1408
72	8000	5588
73	6000	4191
74	6400	3328
75	14800	3828
76	6833	1477
81	23667	4484
82	300	42
83	11200	2228
84	11733	1654
Sum	194500	57385

Source: Own calculations based on BWE 2011.

Appendix 5: RE Capacities on Dena Zones in the Strategic South Scenario, 2030 in GW

DENA Zone	Geothermal energy	Hydro power	Photovoltaics	Wave & tidal power	Onshore Wind	Offshore Wind	Biomass	Sum
21	0.61	0.00	1.52	0.67	4.08	3.99	0.25	11.11
22	0.00	0.05	1.17	0.67	2.47	2.00	0.54	6.89
23	0.00	0.06	1.42	0.00	2.60	0.00	0.59	4.67
24	0.24	0.00	5.10	0.00	4.30	0.00	0.20	9.84
25	0.15	1.85	11.84	0.00	4.43	0.00	0.92	19.18
26	0.10	1.23	8.24	0.00	2.95	0.00	0.61	13.14
41	0.10	0.49	3.72	0.00	2.77	0.00	0.33	7.41
42	0.20	0.98	7.20	0.00	5.54	0.00	0.65	14.58
71	0.00	0.03	0.78	0.00	1.41	0.00	0.32	2.54
72	0.00	0.05	4.20	0.00	5.59	0.00	0.39	10.23
73	0.00	0.04	3.15	0.00	4.19	0.00	0.29	7.67
74	0.06	0.02	3.04	0.00	3.33	0.00	0.25	6.70
75	0.30	0.00	5.37	0.00	3.83	0.00	0.25	9.74
76	0.05	0.62	4.12	0.00	1.48	0.00	0.31	6.57
81	0.00	0.00	1.63	0.67	4.48	2.00	2.89	11.67
82	0.00	0.12	0.00	0.00	0.04	0.00	0.12	0.29
83	0.00	0.00	1.35	0.00	2.23	0.00	0.43	4.01
84	0.00	0.12	1.16	0.00	1.65	0.00	1.35	4.28
Sum	1.82	5.66	65.00	2.00	57.39	7.99	10.68	150.54

Source: Own calculation based on [RE]Shaping 2011.

Appendix 6: Notations of the Model

Sets	
n	set of all nodes
s	set of all power plant types
l	set of all lines
t	set of all times / hours
Parameters	
ε	demand elasticity at reference point
λ	factor defining load levels
ω	factor defining wind generation
σ	factor defining solar generation
τ	transmission reliability margin
$p_{ref\ (t)}$	reference price of demand function at time t
$revision(s)$	factor defining the availability of plant type s
$p_{max\ (l)}$	maximum capacity of line l
$tdf(l,n)$	power transfer distribution factor concerning node n and line l
$g_{\max\ (n,s)}$	maximum of generation capacity at node n of plant type s
$wind_{cap\ (n,t)}$	wind generation capacities at node n and at time t
$wind_{gen\ (n,t)}$	wind generation at node n and at time t
$c(s)$	generation costs for each plant type
$q\_ref(n,t)$	average demand slope of demand function ($p = a + m \cdot q$)
$m(n,t)$	intercept of demand function ($p = a + m \cdot q$)
$a(n,t)$	area under demand function
$q\_area(t)$	
Storage:	
s_eff	conversion efficiency storage
$scap\_max(n)$	storage capacity limit
$s\_in\_max(n)$	storage inflow power limit *(including constraints:*
$s\_out\_max(n)$	storage outflow power limit $sin\_max(n) = sout\_max(n)$ *)*
Demand-Side-Management:	
$dsm\_\max\_pos(n,t)$	limit for adding load (positive)
$dsm\_max\_neg(n,t)$	limit for shedding load (negative)
dsm_factor	factor representing the percentage of possible DSM
t_dsm	maximum time for demand load shifting
Variables	
W	total welfare
$COST(t)$	total cost at time t
$LINEFLOW(l,t)$	line flow on line l at time t
$NETINPUT(n,t)$	net input at node n
$G(n,s,t)$	generation at node n, of plant type s and at time t
$Q(n,t)$	total demand at node n and at time t
Storage:	
$S\_IN(n,t)$	storage inflow at node n and at time t
$S\_OUT(n,t)$	storage outflow at node n and at time t
Demand-Side-Management:	
$DSM(n,t)$	Demand-Side-Management at node n and at time t

Appendix 7: Detailed Lines Congestion

		Reference Scenario		DC Highways Scenario		Strategic South Scenario	
PJS ID	**Type[4]**	**Dual Variable**	**h Congested**	**Dual Variable**	**h Congested**	**Dual Variable**	**h Congested**
82 - 21 (line153)	D	39,914.09	96.43%	10,794.06	90.48%	2,850.27	63.69%
83 - 25 (line19)	D	5,359.87	83.93%	2,481.09	69.05%	3.40	0.60%
82 - 22 (line16)	D	3,182.15	60.12%	10.40	0.60%	0.00	0.00%
23 - 81 (line223)	D	2,213.09	88.10%	1,039.34	66.07%	139.90	11.90%
23 - 81 (line223)	D	2,213.09	88.10%	1,039.34	66.07%	139.90	11.90%
74 - 72 (line185)	D	1,162.46	35.71%	395.13	19.64%	2,213.88	61.90%
42 - 41 (line211)	D	606.49	20.83%	0.00	0.00%	120.86	3.57%
42 - 41 (line211)	D	606.49	20.83%	0.00	0.00%	120.86	3.57%
73 - 23 (line204)	D	573.15	30.36%	4,033.13	67.26%	247.89	8.33%
73 - 23 (line204)	D	573.15	30.36%	4,033.13	67.26%	247.89	8.33%
42 - 41 (line214)	D	500.26	62.50%	709.13	61.31%	1,419.53	80.36%
42 - 41 (line214)	D	500.26	62.50%	709.13	61.31%	1,419.53	80.36%
71 - 22 (line202)	D	322.53	9.52%	1,175.73	13.10%	0.00	0.00%
83 - 24 (line90)	D	82.10	5.36%	117.45	10.12%	3.75	0.60%
22 - 71 (line22)	D	14.67	1.19%	1,192.88	14.88%	0.00	0.00%
41 - 75 (line106)	D	11.86	1.79%	18.35	2.98%	39.25	1.19%
42 - 76 (line219)	D	7.68	1.79%	12.28	1.79%	1.70	1.79%
42 - 76 (line219)	D	7.68	1.79%	12.28	1.79%	1.70	1.79%
22 - 23 (line86)	D	0.00	0.00%	52,725.35	80.36%	0.00	0.00%
41 - 75 (line193)	D	0.00	0.00%	0.00	0.00%	0.00	0.00%
76 - 26 (line220)	D	0.00	0.00%	1.41	1.79%	16.04	2.38%

[4] D: Inner German Lines; D+: Interconnector Lines

76 - 26 (line220)	D	0.00	0.00%	1.41	1.79%	16.04	2.38%
26 - 25 (line222)	D	0.00	0.00%	148.68	14.29%	0.00	0.00%
26 - 25 (line222)	D	0.00	0.00%	148.68	14.29%	0.00	0.00%
81 - 82 (line6)	D	0.00	0.00%	2.43	1.19%	42.46	4.17%
75 - 24 (line189)	D	0.00	0.00%	9.82	2.38%	78.85	4.17%
22 - 82 (line230)	D	0.00	0.00%	0.00	0.00%	2.75	0.60%
22 - 82 (line230)	D	0.00	0.00%	0.00	0.00%	2.75	0.60%
21 - Denmark West (line166)	D+	47,990.52	100.00%	2,955.83	57.14%	45.68	22.62%
21 - Sweden (dc2, Baltic Cable)	D+	24,570.88	100.00%	6,766.77	100.00%	2,858.28	98.21%
France - 42 (line172)	D+	2,586.51	27.98%	1,284.63	20.83%	874.97	12.50%
22 - Norway (dc11, Nord.Link)	D+	1,656.89	97.02%	4,666.65	97.02%	1,228.74	99.40%
81 - Sweden (dc29, Ostseeplattforme n - Schweden)	D+	1,514.26	98.81%	1,138.49	98.81%	1,321.75	100.00%
81 - Denmark East (dc3, Kontek)	D+	1,514.26	98.81%	1,138.49	98.81%	1,321.75	100.00%
25 - Czech Republic (line115)	D+	529.86	15.48%	399.72	14.29%	0.00	0.00%
81 - Poland (dc34, East-West-Energy Bridge (Siemens))	D+	475.44	93.45%	625.56	97.02%	556.10	99.40%
Austria - 26 (line154)	D+	387.04	5.36%	40.92	1.79%	0.00	0.00%
75 - Luxemburg (line69)	D+	354.50	22.02%	235.61	14.88%	147.99	11.90%

Austria - 26 (line38)	D+	201.49	10.12%	53.12	2.38%	346.29	8.93%
75 - France (line173)	D+	90.92	7.74%	70.89	8.93%	227.03	11.90%
Netherlands - 22 (line167)	D+	66.80	8.93%	515.44	30.36%	84.87	6.55%
84 - Poland (line4)	D+	53.15	1.79%	69.97	2.38%	56.87	2.38%
75 - Luxemburg (line70)	D+	20.35	0.60%	242.40	13.10%	303.07	10.12%
25 - Czech Republic (line133)	D+	0.00	0.00%	0.87	0.60%	0.00	0.00%
Austria - 26 (line155)	D+	0.00	0.00%	145.12	1.19%	476.73	4.17%
Netherlands - 74 (line75)	D+	0.00	0.00%	0.09	0.00%	812.29	32.74%

Source: Own calculation based on GAMS.

Appendix 8: Detailed Line Congestion Changes

		Difference in Dual Variable (Congestion index c_i)		Difference in hours Congested	
PJS ID	**Type[5]**	**DC-REF**	**South-REF**	**DC-REF**	**South-REF**
82 - 21 (line153)	D	-29,120.03	-37,063.82	-5.95%	-32.74%
83 - 25 (line19)	D	-2,878.78	-5,356.47	-14.88%	-83.33%
82 - 22 (line16)	D	-3,171.75	-3,182.15	-59.52%	-60.12%
23 - 81 (line223)	D	-1,173.74	-2,073.19	-22.02%	-76.19%
23 - 81 (line223)	D	-1,173.74	-2,073.19	-22.02%	-76.19%
74 - 72 (line185)	D	-767.33	1,051.42	-16.07%	26.19%
42 - 41 (line211)	D	-606.49	-485.64	-20.83%	-17.26%
42 - 41 (line211)	D	-606.49	-485.64	-20.83%	-17.26%
73 - 23 (line204)	D	3,459.98	-325.26	36.90%	-22.02%
73 - 23 (line204)	D	3,459.98	-325.26	36.90%	-22.02%
42 - 41 (line214)	D	208.87	919.27	-1.19%	17.86%
42 - 41 (line214)	D	208.87	919.27	-1.19%	17.86%
71 - 22 (line202)	D	853.21	-322.53	3.57%	-9.52%
83 - 24 (line90)	D	35.36	-78.35	4.76%	-4.76%
22 - 71 (line22)	D	1,178.21	-14.67	13.69%	-1.19%
41 - 75 (line106)	D	6.50	27.39	1.19%	-0.60%
42 - 76 (line219)	D	4.60	-5.98	0.00%	0.00%
42 - 76 (line219)	D	4.60	-5.98	0.00%	0.00%
22 - 23 (line86)	D	52,725.35	0.00	80.36%	0.00%
41 - 75 (line193)	D	0.00	0.00	0.00%	0.00%
76 - 26 (line220)	D	1.41	16.04	1.79%	2.38%

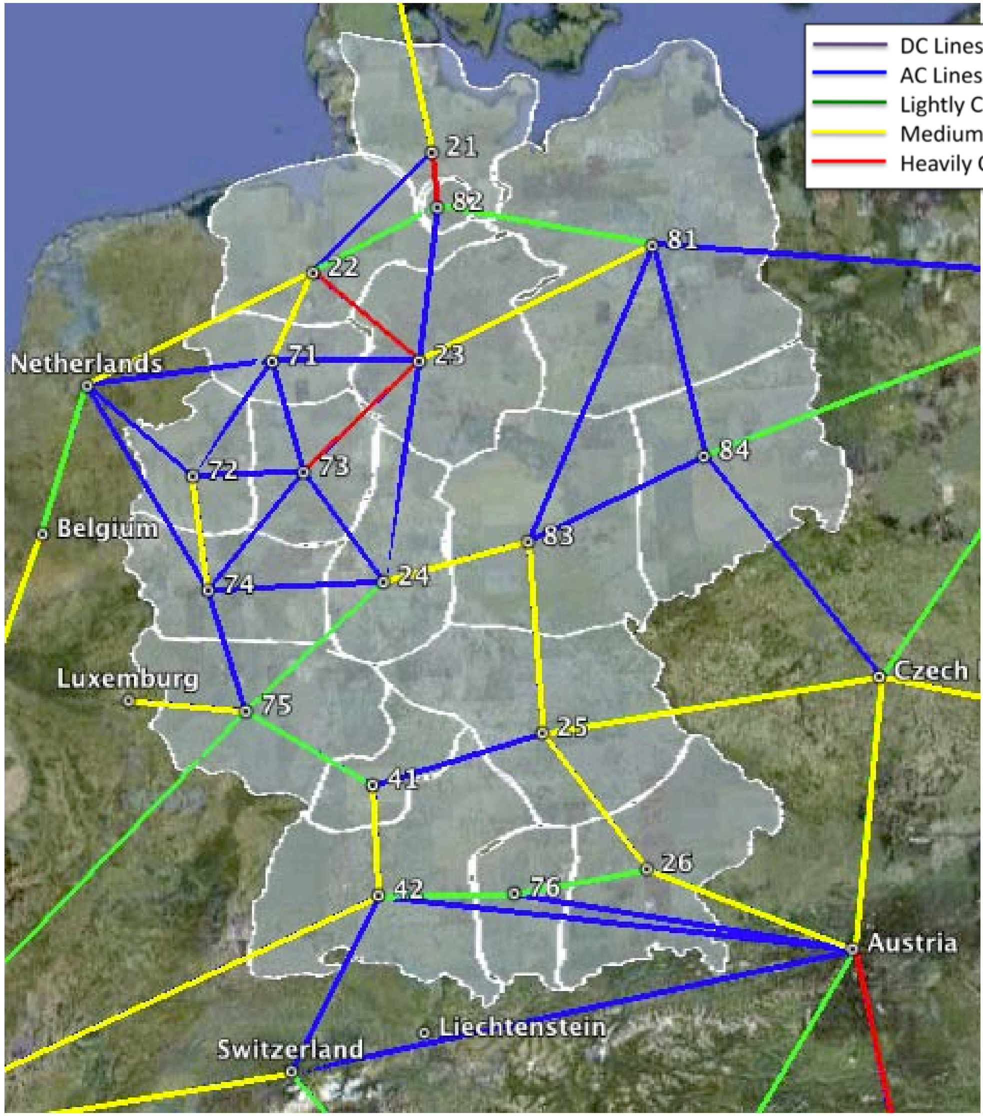
[5] D: Inner German Lines; D+: Interconnector Lines

76 - 26 (line220)	D	1.41	16.04	1.79%	2.38%
26 - 25 (line222)	D	148.68	0.00	14.29%	0.00%
26 - 25 (line222)	D	148.68	0.00	14.29%	0.00%
81 - 82 (line6)	D	2.43	42.46	1.19%	4.17%
75 - 24 (line189)	D	9.82	78.85	2.38%	4.17%
22 - 82 (line230)	D	0.00	2.75	0.00%	0.60%
22 - 82 (line230)	D	0.00	2.75	0.00%	0.60%
21 - Denmark West (line166)	D+	-45,034.69	-47,944.85	-42.86%	-77.38%
21 - Sweden (dc2, Baltic Cable)	D+	-17,804.11	-21,712.60	0.00%	-1.79%
France - 42 (line172)	D+	-1,301.88	-1,711.54	-7.14%	-15.48%
22 - Norway (dc11, Nord.Link)	D+	3,009.76	-428.15	0.00%	2.38%
81 - Sweden (dc29, Ostseeplattformen - Schweden)	D+	-375.77	-192.51	0.00%	1.19%
81 - Denmark East (dc3, Kontek)	D+	-375.77	-192.51	0.00%	1.19%
25 - Czech Republic (line115)	D+	-130.14	-529.86	-1.19%	-15.48%
81 - Poland (dc34, East-West-Energy Bridge (Siemens))	D+	150.12	80.66	3.57%	5.95%
Austria - 26 (line154)	D+	-346.12	-387.04	-3.57%	-5.36%
75 - Luxemburg (line69)	D+	-118.90	-206.52	-7.14%	-10.12%
Austria - 26 (line38)	D+	-148.37	144.80	-7.74%	-1.19%
75 - France (line173)	D+	-20.02	136.11	1.19%	4.17%
Netherlands - 22 (line167)	D+	448.65	18.07	21.43%	-2.38%

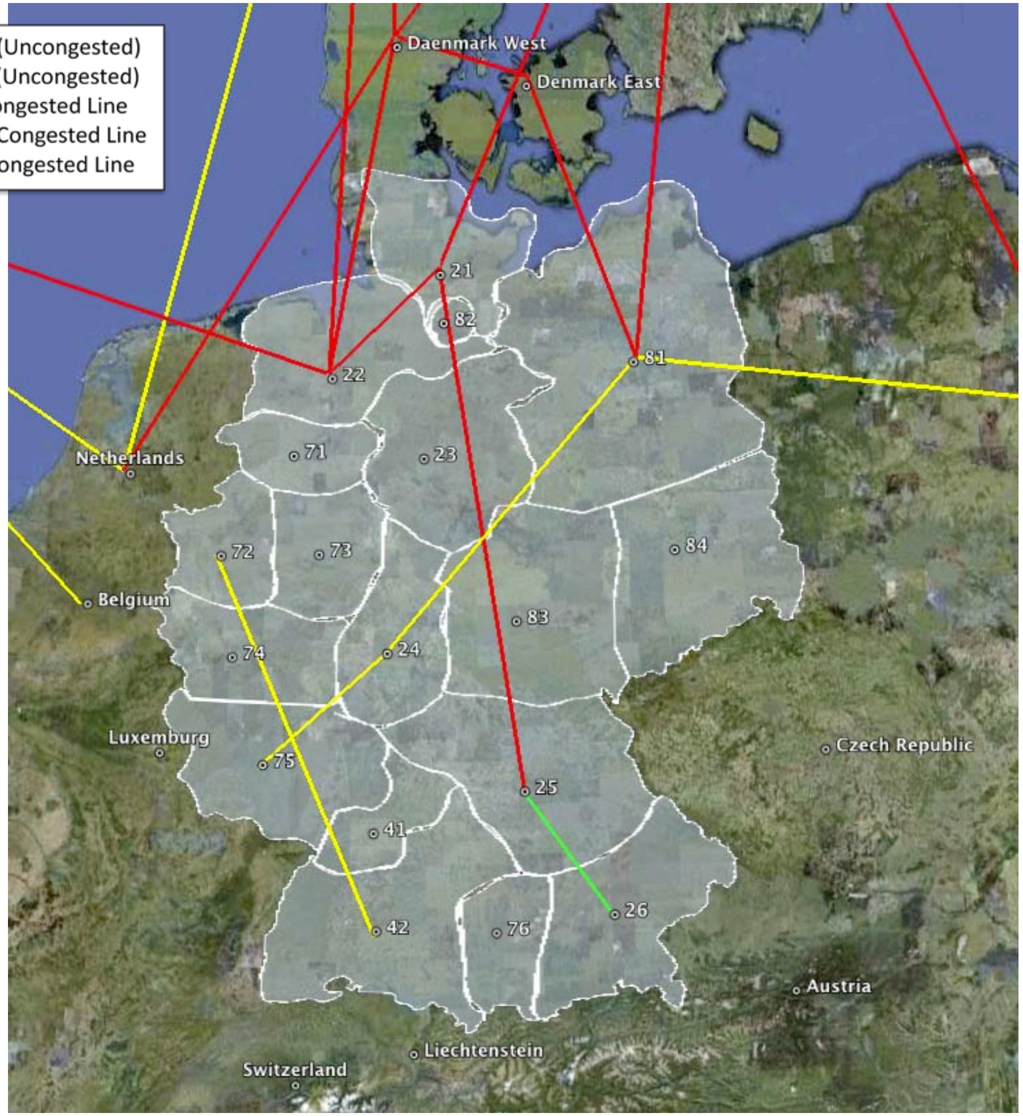
84 - Poland (line4)	D+	16.82	3.72	0.60%	0.60%
75 - Luxemburg (line70)	D+	222.05	282.72	12.50%	9.52%
25 - Czech Republic (line133)	D+	0.87	0.00	0.60%	0.00%
Austria - 26 (line155)	D+	145.12	476.73	1.19%	4.17%
Netherlands - 74 (line75)	D+	0.09	812.29	0.00%	32.74%

Source: Own calculation based on GAMS.

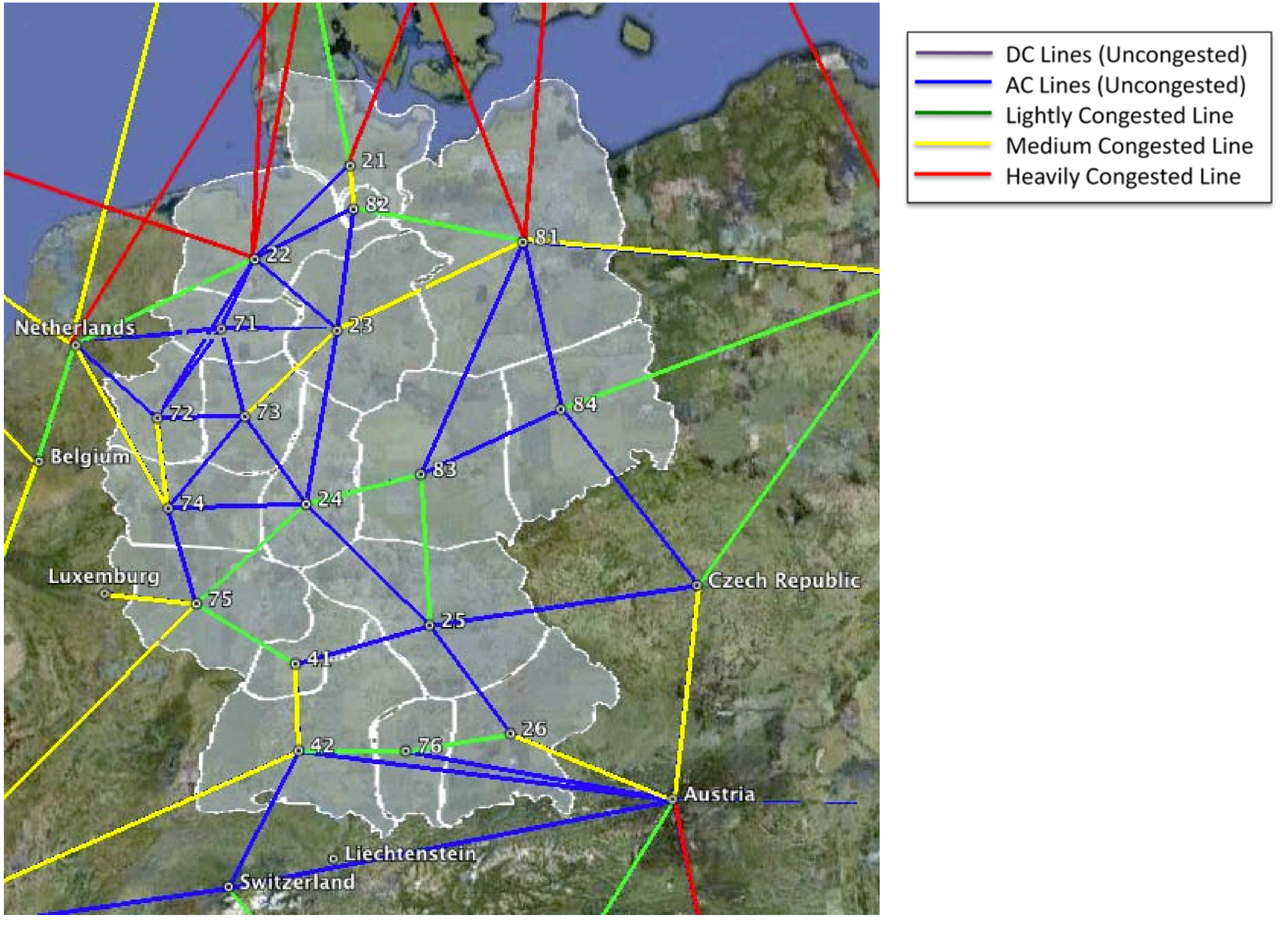
Appendix 10: DC Highways Scenario – Congested AC Lines



Appendix 9: DC Highways Scenario - Congested DC Lines



Appendix 11: Strategic South Scenario - Congested Lines



Source: Own depiction with Google Earth.