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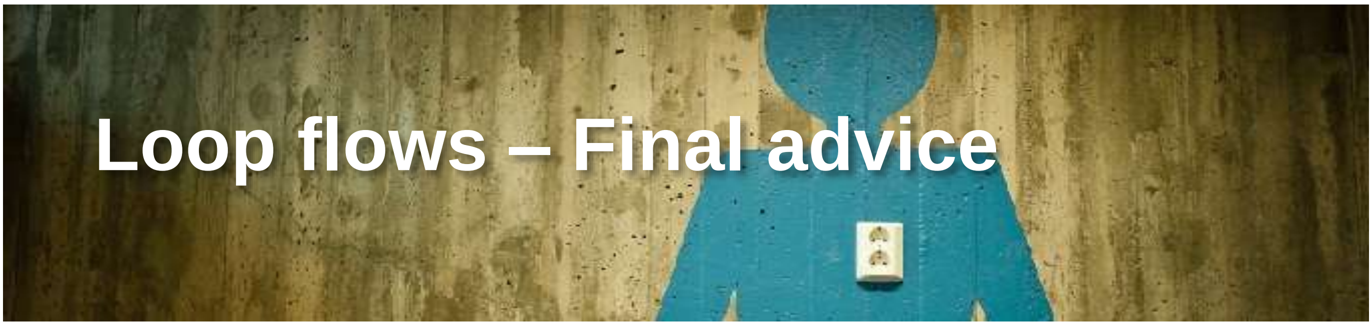

Loop flows – Final advice

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About THEMA Consulting Group

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THEMA Consulting Group is a consulting firm focused on electricity and energy issues, and specializing in market analysis, market design and business strategy.

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ABBREVIATIONS

- AT Austria
- ATC Available transfer capacity
- BE Belgium
- CEE Central East Europe
- CH Switzerland
- CSE Central South Europe
- CWE Central West Europe
- CZ Czech Republic
- DAM Day-Ahead Market
- DC Direct current
- DE Germany
- DK Denmark
- ENTSO-E European Network of Transmission System Operators for Electricity
- FBMC Flow based market coupling
- FR France
- GW Gigawatt
- HR Croatia
- HU Hungary
- IEM Internal Energy Market
- ID Intraday
- IT Italy
- ITC Inter-TSO Compensation
- MW Megawatt
- MWh Megawatt hour
- NL The Netherlands
- NTC Net transfer capacity
- PL Poland
- PST Phase-Shifting Transformer
- RES Renewable Energy Sources
- SK Slovakia
- TSO Transmission System Operator
- TWh Terawatt hour

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1 EXECUTIVE SUMMARY

This report concerns one of the challenges related to the transition to an integrated, decarbonised European power system, namely loop and transit flows. We define the issues and problems related to loop and transit flows and analyse the market impact of measures that may be applied to address these challenges, in particular their impacts on the efficiency of the internal energy market in Europe.

1.1 Loop and transit flows as problems

The market solutions in the electricity market define scheduled market flows and power prices by combining the bids and offers submitted by market participants within bidding zones. These bidding zones are often defined by national borders. The scheduled flows can deviate substantially from the actual physical flows in the electricity grid. In the grid, the flows are distributed according to the paths of least resistance from source to sink. The current market solutions are only to a limited degree able to represent the physical realities of the power system.

The deviations between scheduled flows and physical flows are defined as unscheduled flows. Loop and transit flows are unscheduled flows occurring in an external control area, or host area, i.e. areas not being part of the transaction. We define *loop flows* as unscheduled flows stemming from scheduled flows within a neighbouring bidding zone or control area, whereas *transit flows* are unscheduled flows stemming from a scheduled flow between two or more bidding zones or control areas.

In economic terms, loop and transit flows are external effects experienced by the host areas. Loop and transit flows inflict external costs on the host area when the grid is not able to accommodate the flow and when the scope of scheduled flows within the host area must be reduced. Hence, there are two types of external costs:

- Costs related to security of supply and system services in the host country.
- Costs stemming from reduced capacity for market trade within the host country or between the host country and other areas.

The external effects incentivise implementation of measures that reduce loop and transit flows in the host area, whereas the area where the flows originate does not have adequate incentives to alleviate the problems. Hence, measures are unlikely to be efficient from a wider system efficiency perspective.

1.2 The origin of loop and transit flows

In this report we identify two main factors contributing to the scale of loop and transit flows:

- *Insufficient price signals*: The market prices do not correctly reflect the physical grid, and do not account fully for internal congestions within bidding zones. Unscheduled flows are implicitly prioritized in the current market solution, as the transmission capacities made available to the market (ATC values) are reduced *ex ante* to accommodate expected loop and transit flows.
- *Increased energy imbalances:* The transition to a low carbon energy system implies a reconfiguration of supply and loads in the energy system, and hence the transmission grid. The energy transition creates more frequent and larger deviations of physical flows from scheduled flows. Thermal generation is replaced by location-specific and highly variable renewable generation. At the same time, the grid structure was developed to accommodate more balanced national generation and load. Reconfiguration of the European electricity grid to the future patterns of generation and load is a long-term process.

1.3 Market impact of measures

Host countries and neighbouring TSOs apply various measures to manage and mitigate loop and transit flows. The measures may be classified according to the timeframe in which they are applied and whether they are unilateral or bilateral or multilateral. The results from the qualitative analysis of market impacts reveal:

- Topology measures and installation of Phase Shifting Transformers (PST) directly influence the physical flows in the grid. Such measures may relieve the situation to some extent, but their scope is limited. As physical flows are diverted and the measures not widely coordinated, the measures may create problems elsewhere in the grid.
- Redispatching may be very costly for the host country, and is not necessarily the optimal solution from a system perspective. Countertrading and Virtual Phase Shifting Agreements involves several TSOs and the alteration of generation and loads in several bidding zones. Costs are shared more widely, but the optimal solution is unlikely to be realized. Long-term price signals are obscured.
- Unilateral reduction in the ATC values on interconnectors may reduce system costs in the host country, but at the detriment of efficient trade and market integration.
- Internal bidding zone delimitation alleviates the situation by exposing the market to more efficient price signals. Bidding zone delimitation is likely to be more efficient if regarded from a wider market perspective and with coordinated ATC value determination. Bidding zone delimitation would however mainly affect scheduled flows. Loop and transit flows would still be implicitly prioritized in the market solution and in the grid.
- The efficient solution implies that loop and transit flows “compete” for transmission capacity within the market algorithm, i.e. flow based market coupling with proper representation of the grid across the integrated market area.
- Grid expansion focussing on congested connections would not necessarily reduce loop and transit flows. Grid development should be coordinated across integrated control areas, taking into account the dependency of flows on different connections in the grid.

Analysing flow and market data for 2011-2012 we find strong indications of loop flows in the areas east of Germany (Central Eastern Loop). Moreover, we find that loop flows are correlated with high wind feed-in/power surplus in northern Germany. We further conclude that the prices in the markets do not reflect the limitations in the grid in an efficient way, limiting the efficiency of the price signals provided in the market.

Quantitative impacts of the identified measures are simulated in an electricity market model. The results indicate that internal bidding zone delimitation will be efficient in the areas with strong local imbalances and where these imbalances cause loop flows. A proper grid model, however, is needed to asses if other measures such as the necessity of phase-shifters and to what extent these measures are effective, or if they just re-allocate the problem to other areas.

The quantitative analysis is to a large extent focused on Germany and its neighbouring states whilst the challenges related to loop and transit flows may be relevant for other regions in Europe as well. Germany is focused in our analysis since Germany has taken a lead role in the energy transition (Energiwende), since Germany is located in the centre of Europe and since it already has connected significant amounts of renewable generation to the grid. This has led to increased loop flows in the areas surrounding Germany.

1.4 Recommendations

Efficiency implies activating the lowest cost measures in the short run while providing appropriate price signals for generation, load and grid in order to realise optimal long-term solutions. An efficient measure has to address the challenge that loop and transit flows are implicitly prioritized in the electricity grid. We consider the following measures to be particularly interesting:

1. *Bidding zone delimitation* in order to improve price signals. Both our empirical analysis, the historical analysis of 2011-12 and our model analysis indicate that bidding zone delimitation within control areas could improve the situation.
2. *Flow-based market coupling* (FBMC) may accompany bidding zone delimitation described above. Delimitation of bidding zones only according to where congestion occurs would not be sufficient. The most efficient way to alleviate congestion in the host country may be to reduce scheduled flows across a non-congested connection.
3. *Coordinated grid development.* A long term measure is to make investments in the power system that limits/removes bottlenecks. In order to ensure efficiency, these developments should be coordinated on a regional and/or European level.

Hence, the efficient solution to mitigate loop and transit flow problems from a market-wide perspective implies flow-based market coupling and appropriate bidding zone delimitation. Appropriate bidding zone delimitation implies that all relevant network elements are included in the algorithm, not only connections where congestions occur. With flow-based market coupling transit flows are internalized in the market algorithm and with appropriate bidding zone delimitation loop flows become transit flows.

Flow-based market coupling and bidding zone delimitation will make the scheduled flows more equal to the physical flows since the market solutions better represent the physics. The efficiency of grid development as a measure will be improved with more efficient market solutions in place.

An additional measure could be to address the core issue of priority dispatch for renewable generation. Exposing renewable generation to market prices and terms, including the cost of balancing intermittency, would create more efficient competition and more efficient utilisation of the resources in the power system.

Furthermore, bilateral or regional mechanisms for cooperation and compensation could be a tool for addressing the issues concerning the distribution of costs and benefits related to loop and transit flows which is not directly addressed by flow-based market coupling.

2 INTRODUCTION AND OVERVIEW

This report describes and define loop and transit flows, the issues and problems related to loop and transit flows and the impact of measures applied to manage and mitigate loop and transit flows.

Loop and transit flows denote deviations between scheduled flows (defined by market transactions) and physical flows (the actual flows in the electricity grid) that are caused by scheduled flows within another control area (loop flows) or by scheduled flows between two or more external control areas (transit flows). Such flows constitute problems when they imply that security margins are or may be threatened in the host area, requiring costly measures to be implemented.

The report discusses market and distributional effects of measures that are and can be implemented in order to limit loop and transit flows. Measures could be taken by individual countries or on a regional/European level and they can be both short-term and more long-term of nature. The measures are discussed against the overall goal of ensuring social welfare, including system security, and their ability to promote short-term market efficiency including cross-border trade, and efficient long-term investment signals.

Moreover, based on market data and physical flow data from 2011-2012 we have identified loop and transit flows in the European electricity system. Applying a detailed correlation analysis we test to what extent different variables may explain the origin of the loop and transit flows.

Finally, using a day-ahead fundamental power market model, we have modelled the market impact of different measures that may be applied to resolve loop and transit flow challenges.

Based on the theoretical framework we developed, the historical analysis conducted, and the model simulations performed, we give recommendations as to what measures are best suited and the most efficient in resolving loop and transit flow problems.

2.1 Policy and market context

The European electricity system and electricity markets are in the middle of a profound transition. Traditionally, the electricity systems in Europe have been operated and developed as integrated national systems. Consumption, generation, and grid have been developed in parallel and in a balanced manner accommodating a steady growth in consumption. The interconnection and exchange between control areas has generally been limited. Hence, the configuration or topology of the national electricity systems reflects differences in national energy resources, industry structure, settlement patterns, etc. Now this situation is about to change significantly.

The current discussion related to loop flows can be seen as a symptom of the transition of the electricity system to a low-carbon economy and the integration of national and regional markets into an internal European market. Below we have identified seven areas of development that are relevant for loop flows. National policies and support schemes for renewable generation, for which the location and generation patterns are often determined by weather and nature, have led to rapid transition of the power supply affecting regional power flows. At the same time the necessary strengthening and adaptation of the grid, more coordinated grid operations, increased demand response, increased market integration and development of new methods for allocation of costs and benefits are not fully developed on a regional or European level.

We have identified seven areas where significant development is crucial for the energy transition. These areas are shortly described below and illustrated in Figure 1:

- *Renewable generation*. European energy supply is moving away from a thermal based system towards a low-emission system. The configuration of electricity supply is profoundly changing. Generation must to a larger extent be located where the renewable resources are available. Renewable generation depends on weather conditions and has an

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intermittent generation pattern. In addition, the resource endowments vary geographically, increasing the demand for cross-border power exchange in various market timeframes.

- *Smarter demand*. The demand side is changing. The degree of change and the timing of change are uncertain, but more demand response, smart solutions and energy efficiency measures are expected. In addition new power demand will be added when transportation and other consumers are expected to switch from direct burning of fossil fuels to electricity.
- *Coordinated renewables policies*. Investments in renewable generation have mainly been driven by national policies and support schemes. The policies and support schemes have varied significantly over time and between the Member States, creating different incentives for investments in different countries at different times. We expect these policies to be more coordinated in the future on a regional or European level, also promoting increased predictability for the market and for investors.
- *Market integration*. Increased market integration and improved markets solutions (target models) across regions and across Europe have yielded regional efficiency gains. This development is expected to continue. Market integration and improved market solutions facilitate the utilisation of resources across the power system and provide a different and much more efficient system than what we have seen so far.
- *Integration of grid development*. The current grid configuration does not match the rapid changes in the distribution and characteristics of electricity supply. The systems have been operated and developed from a national perspective. Thus, the European grid structure reflects the national basis from which it has been developed, which means that the inter-European grid structure is weaker than the national grid structures. The inter-European perspective is expected to grow stronger in the future.
- *TSO cooperation*. Transmission grids are operated on a national basis. The organization of the system areas is to a large extent according to state borders. As electricity flows do not adhere to political borders but to the laws of physics, both TSO cooperation and the distribution of costs and benefits of electricity flows are and will be controversial issues between "power neighbours" in Europe during the transition phase. The issues need to be addressed in order for the development of the internal energy market and the energy system transition to be successful.
- *Efficient cost allocation*. As markets and power systems become more integrated we expect a growing demand for means for efficient allocation of costs and benefits across regions and across Europe. Allocation of cost and benefits is crucial when investments are motivated by regional/European needs.

Figure 1: Seven areas of development in the electricity transition process.

	Before	In the future	Progress to date
Power supply	A significant amount of thermal power generation.	Low (or no) emissions. Large share of intermittent generation.	???
Demand	Steady growth in consumption. Low demand flexibility.	Smart solutions, demand response and distributed generation creates a new dynamic in the power system.	???
Politics	Policies (e.g. support schemes for RES) are nationally based.	European policies providing harmonized incentives and support schemes.	???
Markets	Market design and market maturity varies. National power markets.	Common European market design and integrated markets aimed at optimizing resources across Europe.	???
Grid investment	National grid and nationally motivated investments. Limited interconnections.	European planning and grid investments aimed at optimizing resources across Europe.	???
Grid operation	National TSOs with a national mandate cooperating with neighbors when beneficial.	TSOs cooperating closely. Acting as one TSO.	???
Allocating costs and benefits	Nationally based tariffs and short-term ITC compensation.	Mechanisms for allocating costs/benefits promoting efficient European grid investments.	???

To some extent, loop flows may be regarded as a short-term issue. In the longer term one might assume progress on several of the seven developments, such as more integrated and efficient markets, improved adaptation of the grid structure, and distribution and composition of generation that is better suited to optimize system efficiency. In addition, it is likely that the demand side will become a stronger participant in the balancing of the future system, a development which is only just starting. These developments may all serve to limit the challenges related to loop flows. *If not properly addressed, however, increasing shares of renewable generation in the power system may increase loop flows.*

The far right column of Figure 1 illustrates that in all areas there is a gap to be filled in order to realize the desired solution. The gap can be more or less significant, and bridging the gap can be more or less challenging. The energy transition requires closing of the gap in all seven areas, and is thus quite a challenging task. First, progress in each of the seven areas is complex on an individual basis. Second, there is a significant need for coordination across areas and across Member States and regions. Developments in the different areas are interlinked and the issues have to be dealt with in parallel. Fast progress in one of the seven areas may challenge the progress in some of the other six areas. Fast progress in one Member State may create challenges in other Member States. The transition and the individual development processes will thus take time.

Currently the challenges are exacerbated by the rapid developments on the supply side (new wind generation) while the grid structure and the market solutions are tailored to the “old” system. The challenges of the “old” grid system are not only related to the physical grid structure, but also to the organization of the system areas – to a large extent following state borders. Investments in physical infrastructure and more efficient cross-border trade are needed in order to successfully transform the European energy system. In the short term the issue of loop flows needs to be addressed to make sure that distributional issues do not act as a barrier to the needed progress on market integration and grid development.

2.2 Understanding the issue

This chapter describes the issue of loop and transit flows from a conceptual perspective. First, we discuss the ability of market solutions to fully capture and represent the physical flows in the power system. Second, we outline a theoretical framework for the discussion of the report by defining different categories of flows. Next, we discuss possible negative effects of loop and transit flows and identify the core problems associated with loop and transit flows. Finally, we discuss the origin of loop and transit flows.

2.2.1 The power markets and the power system

In order to understand the controversy of loop and transit flows one has to understand how the electricity market works, and the relationship between the market solutions and the actual physics of the power system, the way power flows, and the way that the operation of the power system is organized.

We would like to point out three aspects of electricity as a commercial commodity that explain the loop flow problem:

1. *No direct buyer-seller connection*. The market solution defines the distribution of generation and consumption, basically without taking the configuration of the grid into account within a market area.
2. *Transmission according to physical laws.* The electricity is transported from the generators to the consumers through the electricity grid. The flows are distributed according to Kirchhoff's second law and take the path of least resistance. Hence, the physical flows are not in line with the market schedule.
3. *Grid organization and cost distribution.* The cost distribution in the grid is organized according to national borders and defined TSO control areas. The path of least resistance does not regard such definitions. Hence, commercial trades affect flows across several control areas, thereby creating external effects.

Significant deviations may reduce system security and add to the costs of system operation in other control areas. In addition, it distorts price signals: paying for what you get (and not playing for what you do not get) is a prerequisite for market efficiency in all markets.

2.2.2 Distinction between flows

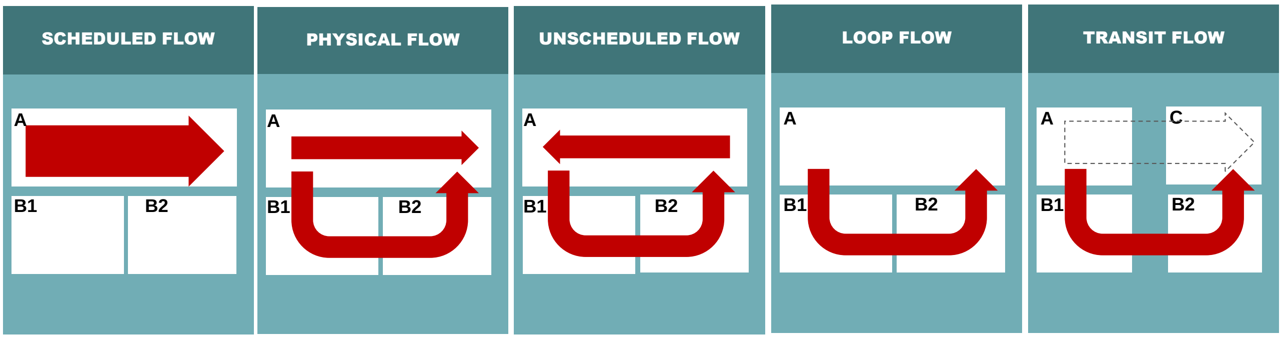
In this section we define various kinds of flows with reference to the simplified market situation depicted in Figure 2. A and B in Figure 2 are two control areas where area B may experience an internal congestion between B1 and B2. Note that B1 and B2 may represent two bidding zones within one control area or two control areas. The different flows are defined in relation to a commercial transaction within A. Generators are located in the left part of A (surplus area), while consumers are located on the right (deficit area).

- *Scheduled (market) flows.* Commercial transactions define the flows scheduled by the market, i.e. between consumers and suppliers according to the market solution. Hence, the scheduled flows simply describe the contracted (net) import/export between and within the defined zones in the system. A scheduled flow within control area A is illustrated in the first panel in Figure 2.
- *Physical flows.* The physical flows are the actual measured flows in the physical grid – the electrons following the path of least resistance from source to sink (according to Kirchhoff's first law). The second panel in Figure 2 illustrates that the scheduled flow within control area A yields a physical flow within control area A that is less than commercially contracted, and that the rest of the volumes flow through B1 and B2.
- *Unscheduled flows.* Unscheduled flows are the difference between physical flows and scheduled market flows as shown in the third panel in Figure 2. Unscheduled flows are

external when they occur outside the control areas involved in the scheduled transaction. External unscheduled flows may be loop flows or transit flows:

- *Loop flows.* Loop flows are the unscheduled flows occurring in external control areas caused by origin and destination of a scheduled flow within one control area. In our example, the physical flow through B1 and B2 is a loop flow caused by an internal schedule in A as shown in the fourth panel in Figure 2. We denote B as the host area (and B1 and B2 as host areas) for loop flows.
- *Transit flows*. Transit flows are external unscheduled flows stemming from a scheduled flow between two adjacent control areas or bidding zones. Panel five in Figure 2 depicts transit flows. Here the scheduled flow is not internal to A, but takes place between A and C. A and C can be two different bidding zones or two control areas.

Figure 2: Different types of flows



2.2.3 Loop and transit flows as a problem

When we refer to loop and transit flows as a problem, we mean the situation where unscheduled flows create congestions, increase system costs, and challenge system security in the host area (B). In other words, loop and transit flow problems are defined as negative external effects related to a commercial transaction. Potential negative effects of loop and transit flows include:

- *Reduced market efficiency*. Grid and generation are not efficiently compensated for what they deliver, and consumers are similarly not exposed to the real cost of the electricity they consume. In addition, the calculated capacities may have little relevance if loop flows dominate. Thus, the resources employed in the power system may not be optimally utilized.
- *Reduced security of supply*. The market is not able to efficiently convey the needs of the physical power system in the form of efficient price signals (incentives) to generators, consumers and grid owners. Sometimes there are not sufficient remedial measures available and system operation under proper security criteria cannot be restored. Failures could then result in black-outs.
- *Missing incentives and adverse distribution effects*. The areas “hosting” physical flows incur costs, and the areas that use other bidding zones to realize their scheduled flows save costs, creating a situation that is perceived as unfair. Limiting the interconnector capacity made available to the market (ATC values) reduces interconnector revenues, and unscheduled physical flows violating security criteria requires implementation of costly remedial measures in host areas (different measures are further described in chapter 3).

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Loop and transit flows do not always create challenges and costs for the host area. In some situations loop flows may counteract scheduled flows in the host area and reduce system costs.[1] However, our focus is on situations where loop and transit flows create or exacerbate system challenges or create adverse distributional effects.

Returning to our simplified example in Figure 2, the problem related to the loop flow in the fourth panel and the transit flow in the fifth panel is a congestion occurring between B1 and B2, or between B and C, respectively. The cause of the problem in this case is the scheduled flow within A as we assume that both B1 and B2 are balanced. In reality, however, the situations are typically a bit more complicated. The congestion may occur due to a combination of multiple loop and transit flows, internal flows within B or trades between B and C. Moreover, the contribution to the problem by the various sources may shift over time. However, the scheduled flows within biding zones are always at the core of the problem.

[1] Unscheduled flows in the opposite direction of scheduled flows make it possible to increase the capacity for scheduled flows in the same direction.

3 PROPOSED MEASURES

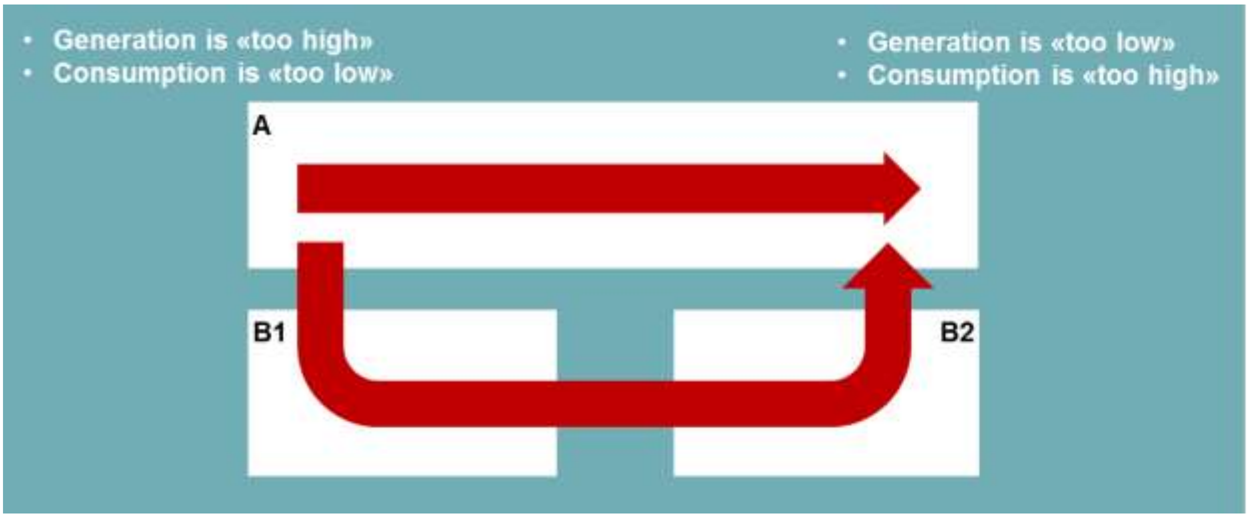
In this chapter we explore what measures are available when loop and transit flows create external problems, and what the implications of different measures are. First, we elaborate on the purpose of the measures. Second, we define the various measures used to either reduce loop flow problems or to limit the negative effects of loop flows, and we discuss how the various measures affect the market and the distribution of costs.

3.1 Purpose of measures

There are a variety of possible measures to limit or remove problems created by loop and transit flows, but they all aim at addressing the same basic problem: to ensure that the grid is able to efficiently handle the physical flows that the market solution creates. Or, put slightly differently, to apply corrective measures to account for the market solution not properly reflecting the physical realities of the power system. A measure is efficient if it handles the problem in a cost-efficient way, i.e. utilizes the least cost resources. Efficiency also implies that measures are taken *where* they are least costly, be it in relation to the scheduled flows, i.e. the transactions causing loop and transit flow problems, or within the host country, and that the applied measures do not obscure long-term investment signals.

In order to discuss the implications of different measures we use the simplified loop flow situation depicted in Figure 3. The problem is caused by the scheduled flow from west of control area A to east of control area A. Hence, the simplified underlying situation is imbalances in the market in A, i.e. high generation compared to (relatively) low consumption in A west, and low generation compared to (relatively) high consumption in A east.

Figure 3: Imbalances in control area A causing loop flow problems in control area B



Moreover, we relate the analysis of the the market impacts of measures for loop and transit flows to the following market situation:

- There is one market uniform price in area A and one uniform market price in area B.
- The uniform market price in A is determined by the marginal costs of generation in the east of A.
- Marginal costs in B1 and B2 are the same and equal to the uniform price in B.

- The marginal cost of generation in A west is lower than the price in A and the price in B.[2]
- The uniform market price in A is lower than the uniform market price in B. (Note that if there are no congestions on interconnectors the marginal generation cost in A east, B1 and B2 are equal and the market price in A is equal to the market price in B.)
- The market solution implies that scheduled flows go from west to east in both systems, leading to a breach in the security margins internally in B.

The impact of measures may vary for different situations in the power system. In the evaluation of some of the measures it is useful to distinguish between these four alternative situations:

1. *No congestion.* Loop flows occur but do not create scheduled or physical congestions, nor are the sum of scheduled flows between B1 and B2 and loop flows sufficient to create congestion between the host areas. In that case we would have the same market price in the whole system, no congestion rent would accrue on any of the borders and the security criteria in B are not violated.
2. *Internal congestion in the host area*. Loop flows create a physical internal congestion within the host area, i.e. loop flows prevent scheduled flows between B1 and B2. The cross-border connections (between A and B) are not congested. The market price is identical in the whole system. Hence, there is no congestion rent to be earned on any of the cross-borders interconnectors. Loop flows negatively affect internal system operations in the host country.
3. *Cross-border congestion*. Cross-border scheduled flows from A to B1 are limited by loop flows. In addition, loop flows create a physical internal congestion in the host area. The market price in B is higher than the market price in A and congestion rents accrue on the border between A and B1.
4. *Full loop flow congestion.* Loop flows alone create congestion between A and B1 and internally in the host area. No congestion rent can be earned on the cross-border connection A-B1. With the price in A being lower than the price in B, there might be scheduled flows from A to B2, generating congestion rents on this interconnection.

Figure 4: Alternative loop flow situations

	A – B1	B1 – B2	B2- A
1.	No congestion	No congestion	No congestion
2.	No congestion	Congested	No congestion
3.	Congested	Congested	No congestion
4.	Fully congested by loop flows (ATC=0)	Fully congested by loop flows (ATC=0)	No congestion

[2] If the marginal cost in A east is higher than the marginal cost in B the price in A would be higher than the price in B, thus inducing exports from B to A and thereby counteracting the loop flow.

In situation 1 of Figure 4 loop and transit flows do not pose a problem. Security margins are not violated and without congestions on borders there are no congestion rents to miss. In situations 2-4 measures have to be taken to handle the congestion and maintain security margins. These measures may affect market prices and efficiency in different ways. Apart from measures directly addressing the capacities in the grid, these measures must either reduce generation (increase consumption) in the west or increase generation (reduce consumption) in the east, i.e. involve some degree alteration of generation and/or load patterns.

For example, if technical measures to reduce or divert flows from the congested line(s) are exhausted or unavailable, the situation must be managed by reducing generation in the west and increasing generation in the east. (For simplicity reasons we disregard load adjustments in our example.) If the interconnection between A and B1 is not congested, the adjustment may be made in A or in B1. In our example, marginal costs in B1 are higher than in A west, implying that the cost-efficient solution is to reduce generation in B1. Similarly, since the marginal cost of generation in A east is lower than the marginal cost of generation in B2, generation in A east should increase. The adjustments should take place until the congestion in B is relieved and security margins restored.

3.2 Possible solutions

Loop and transit flows create adverse external effects in other markets by reducing the scope for trade and increasing system costs. Different measures correct or affect these external effects to varying degrees, as we discuss in the following paragraphs.

In the description discussion of alternative measures to address and manage problems caused by loop and transit flows we distinguish between short-term, medium-term and long-term measures:

- *Short-term measures* are used by the TSOs to manage the problem of loop flows in order to adjust the outcome of the market schedule (DAM and ID). In that sense, short-term measures may be thought of as curative. These measures include the use of topology measures and other technical measures in the grid. Such measures may require some time to implement, but are applied more or less during real-time operation. In addition the TSOs may make bilateral or market-based agreements for the adjustment of generation and load as a short-term measure.
- *Medium-term (market design) measures* change physical flows by affecting the market solution, i.e. scheduled flows. Such alteration could be carried out unilaterally in the host area, across the border between areas or within area A. We label them medium-term because they can be implemented through institutional changes and are applied in order to limit loop flow problems and the need to apply short-term measures in real-time. (They can also be thought of as short-term preventive measures.)
- *Long-term measures.* Long-term measures aim at removing the fundamental reasons for the problem through investments in the grid and improvements of the market design. Long-term measures are preventive.

We may also distinguish between *internal* and *cross-border* measures. The internal measures are taken unilaterally by the TSO in the host area while cross-border measures are taken multilaterally by two or more TSOs.

The efficient solutions are attained when optimal market incentives are provided in different time frames. Measures affect price signals in the market to varying degrees. Long-term efficiency implies that investment decisions take loop and transit flows into account, including location of new power generation and load. In general, long-term efficiency requires that market prices reflect the underlying costs. Adverse price signals that distort investment decisions may exacerbate loop and transit flow problems and increase overall system costs. Hence, we discuss the impact of the different measures in terms of the distribution of costs, the price impacts and the overall efficiency of the solution.

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3.3 Short-term measures: Topology and system operation

3.3.1 Physical grid measures

There are several measures that can be used by TSOs both in the planning stage and in real time, in order to relieve congestions in the grid and manage problems related to loop flows. Topology measures may increase the ability of the grid to accommodate the physical flows associated with the scheduled flows. Installing Phase Shifting Transformers (PSTs) may change the pattern of physical flows in the grid and particularly reduce the load on critical lines. Both topology changes and installation of PSTs may be carried out unilaterally or coordinated between TSOs over a larger region. If carried out unilaterally, the cost is borne by the host TSO, whereas costs may be shared if the measures are coordinated between several TSOs.

The contribution from such measures is situation specific and probably limited in time and scope. In particular the effect is uncertain in the longer term. In smaller control areas with large loop or transit flows, such measures may not be sufficient to maintain adequate system security at all times. Topology measures and PSTs may be useful complements to other measures, such as ATC values and indirect redispatching via the market algorithm.

As both topology changes and PSTs affect the distribution of flows, their implementation will alter flows in other parts of the system and may give rise to or increase loop or transit flow problems there.

Topology measures and installation of PSTs affect the market solution and market prices to the extent that ATC values may be increased. However, they will not incentivize significant adjustments of generation and load patterns, and are not likely to provide long-term signals to investments in generation and load, depending on to what extent PSTs are considered to be a short-term or long-term measure.

3.3.2 Ex ante alteration of generation and load

In addition to topology measures and PSTs it may be necessary and/or more efficient to alter the generation and load patterns in order to relieve congestions and to avoid violations of security criteria. Alteration of generation and load can be achieved by countertrading and redispatching by the TSO.

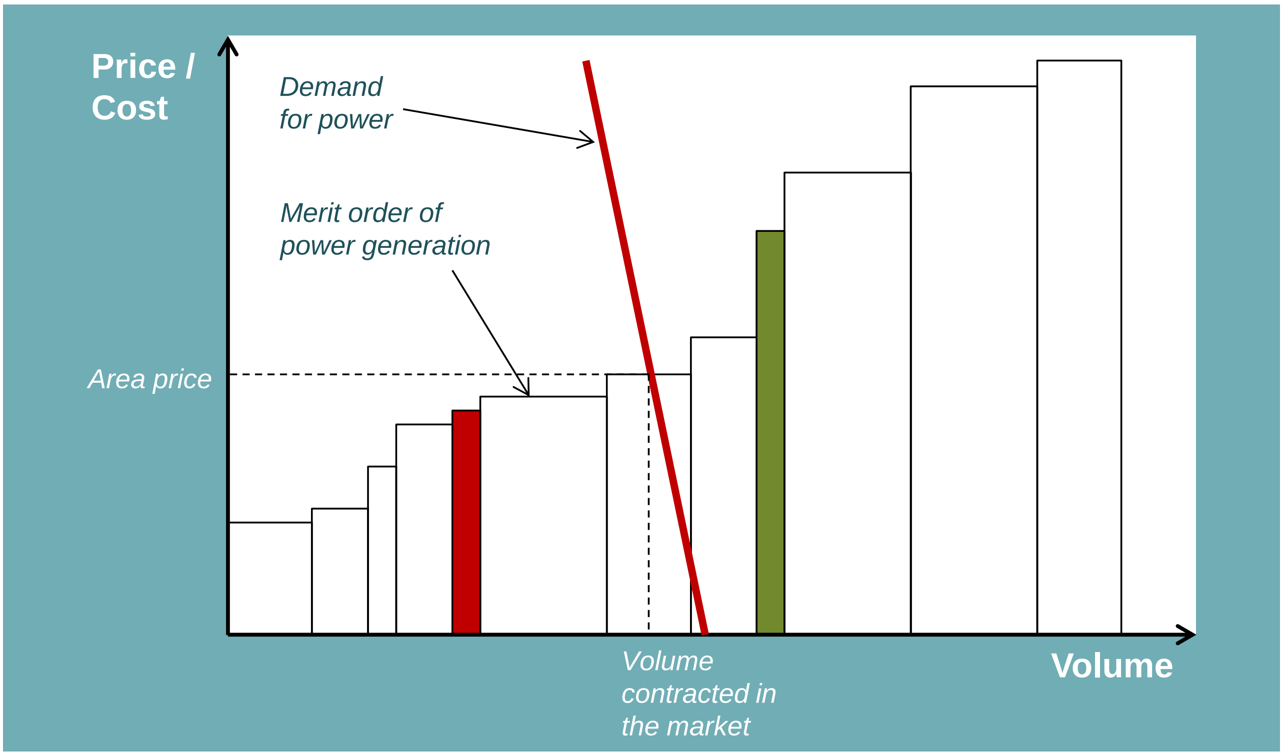
According to the definitions in ENTSO-E Draft Network Code on Forward Capacity Allocation[3]:

- *Countertrading* implies a cross-zonal energy exchange initiated by the system operator(s), i.e. paying suppliers (consumers) in the surplus area to reduce (increase) their generation (consumption) and suppliers (consumers) in the deficit area to increase (reduce) their generation (consumption) in order to relieve a physical congestion.
- *Redispatching* implies a measure to alter generation and/or load, activated by one or several system operators in order to relieve a physical congestion.

Hence, countertrading may be understood as a special case of redispatching. The purpose and consequence of the two are similar, i.e. to alter generation and or consumption in order to adjust physical flows. Consider the market solution depicted in Figure 5. According to the merit order curve and the demand for power, the “Area price” is the marginal cost of the most expensive generation capacity necessary to cover demand. Now assume that this market solution congests a bottleneck within a bidding zone or between two bidding zones, implying that the resulting generation and demand is not attainable.

[3] ENTSO-E, 28 March 2013.

Figure 5: Alteration of generation by redispatching or countertrade – limiting generation (red volume) and replacing it with generation from another provider (green volume)



Redispatching within a bidding zone implies that power generators in the surplus area are instructed to generate less power than planned according to the market solution (red generator in Figure 5) while power generators in the deficit area (green generator) are instructed to generate more. Countertrade would imply a similar alteration between two control areas, coordinated between the TSOs, where the TSO in the surplus area pays for reduced generation or increased demand, whereas the TSO in the deficit area pays for increased generation or reduced demand, each using resources in their own control area. Countertrading would typically be used to relieve a congestion between A and B1, but as generation in A is reduced, loop flows through B would be reduced as well, thereby reducing the need for redispatching within B.

Countertrading and redispatching increase system costs of the TSOs and thus the costs to the tariff customers. The underlying scheduled flows and commercial transactions (market prices) remain the same. Cross-border measures require close coordination between TSOs and cost sharing arrangements.

In order to relieve the congestion, the red generator in Figure 5 is compensated for the revenue loss of reduced generation and the green generator is compensated for the cost of increasing generation above the market price (area price). In addition there is a cost to society due to incorrect market prices. Market prices in the system area stay at the non-congestion level. Thus, redispatching and counter trade do not provide efficient locational signals for investments. The TSOs are however incentivized to invest in internal grid reinforcements to relieve the internal congestion if the costs associated with countertrade and redispatching are higher than the investment cost. Hence, the investment incentives are distorted between grid investments on the one hand and investments in generation and load on the other.

If the redispatching is uncoordinated, and in particular if it is carried out unilaterally by the TSO in B, the most efficient resources may not be utilized. It may be that the most cost-effective way, from a broader system perspective is to reduce generation in A west, and not in B1. This illustrates a situation in which loop and transit flows are prioritized on interconnectors and in the grid in B.

On the other hand, reducing generation in B1 may well be the most cost-efficient handling of the internal congestion in B. In that case the redispatching is efficient from a short term resource utilization perspective, but the redispatching costs are fully borne by the TSO in B, although the problem originates in A. Note too, that redispatching closer to the congestion may manage the problem more directly and efficiently, as all changes in flows, and in generation and load patterns, are distributed across the entire grid. The effect of measures taken farther away from the problem is diluted.

Sharing the cost of unilateral redispatching among TSOs may be a more efficient measure than sharing the redispatching across system areas. Virtual Phase Shifting Transformer (VPST) agreements are contractual arrangements between TSOs aimed to address the challenges associated with loop and transit flows. VPSTs can be seen as a redispatching agreement between TSOs where cross-border flows are limited through a coordinated redispatching procedure including cost sharing arrangements. Hence, VPST agreements may increase the efficiency of loop flow management compared to what can be achieved through countertrading or uncoordinated and unilateral redispatching. For example, TSOs can agree that if the physical flow on the border exceeds a given level, the TSO in the export country buys a given volume of redispatching in A, thus limiting the cost of redispatching in B.

3.4 Medium term measures: Market design

3.4.1 Reduce ATC values

In order to avoid or reduce redispatching costs, the TSO in B may wish to reduce ATC values between A and B1. This will limit the scheduled flow from A to B1 and affect scheduled flows in addition to loop flows. As we have assumed that the marginal generation in A is located in the east, generation in A east will be reduced and not generation in A west. The loop flow stays the same. To make up for the reduced scheduled imports from A to B, generation in B must increase. Increased generation in B2 would reduce the internal congestion. As long as there is one price in B, however, the distribution between B1 and B2 depends on the merit order curves. Hence, the TSO in B might still have to apply redispatching, but the magnitude of redispatching would be reduced.

The price in A would reduce and the price in B would increase. Hence, although the scheduled flow from A to B1 would decline, the price difference would increase. Subsequently, the total effect on the congestion rent is uncertain. (If we assume there is a larger system, generation in A may not be reduced, but exported to other areas instead, thereby changes prices and scheduled and physical flows there.) Such behaviour is probably not permitted, cf. the complaint about Swedish ATC practices on the Danish border (although the redispatching costs within Sweden were not explained by loop flows).[4]

3.4.2 Internal bidding zone delimitation

Bidding zone delimitation in B

In principle, countertrading and redispatching can be avoided or limited by introducing bidding zones within control areas as a preventive measure. In order to relieve the internal congestion, the TSO/regulator in B may define B1 and B2 as two different bidding zones and define an appropriate ATC value between them, taking the expected loop flow into account.

[4] Commission Decision of 14.4.2010 relating to a proceeding under Article 102 of the Treaty on the Functioning of the European Union and Article 54 of the EEA Agreement (Case 39351 – Swedish Interconnectors). http://ec.europa.eu/competition/antitrust/cases/dec_docs/39351/39351_1211_8.pdf

Per definition the ATC value between B1 and B2 would be binding, and thus prices in B1 and B2 would differ. Since there is a surplus west of the congestion, the first effect is to reduce prices in B1. In our example, we assume that generation in A west has very low marginal costs (cf. our simplified example above) and the capacity in A west is fully utilized. Hence, it is likely that only generation in B1 is reduced and that generation in A west stays the same. Now the price in B1 is lower than in B2 and the flow on the congested connection between B1 and B2 is thus reduced. In order for all demand in the east to be covered, generation in B2 or in A east must increase. Thus prices must increase as well. Since (by assumption) the marginal cost of generation is lower in A east than in B2, generation in A east will increase. (Some of the increased generation will flow through A back to B1, thereby probably creating a bottleneck between A and B1, if there was not one before.) Total generation in B is reduced and total generation in A increases.

The price in all of A and in B2 increases. Hence, generators in B1 lose due to lower price and reduced generation, whereas all generators in the other bidding zones gain from the higher price in A and B2, and generators in A east even due to increased generation. The price signals that generation in B1 is worth less than generation in other locations, even in A west which has a larger surplus than B1.

The loop flow from A west through B1 to B2 stays the same. Since prices differ in A west and B1, the congestion rent, probably shared between the TSOs in A and B, increases. Moreover, there is a scheduled flow and congestion rent on B1-B2 accruing to the TSO in B.

On the other hand, that bidding zone delimitation in B and higher prices in A may induce increased generation in A west. Thus loop flows through B will increase. Then the price in B1 must be reduced further in order to reduce the physical flow within B sufficiently to relieve the congestion.

In situations where merit order curves are more equal the results may not be as clear-cut as in this simplified example, e.g., some of the increase in generation in the east may occur in B2, see chapter 4.

Bidding zone delimitation in A

Although the adjustments in generation in B1 may be efficient from a system-wide perspective (according to the marginal costs of generation in the different bidding zones) when B is split in two bidding zones, locational price signals are not. The next step to consider is whether bidding zone delimitation in A may provide more efficient price signals, effectively transforming the loop flow through B to a transit flow since the scheduled flow from A west to A east would now be export flows across the interconnection from A (formerly A west) to C (formerly A east). However, since there is, by assumption, no congestion from A to C, the traded volume would stay the same and so would prices.

It follows from the example that splitting A into several bidding zones would not necessarily reduce unscheduled flows, but merely transform the loop flow to a transit flow. With uncoordinated ATC delimitation no congestion would occur on the interconnection between A and C, and the scheduled flows would still produce the same unscheduled, prioritized flow through B. (The ATC value for transmission within A would not be binding.)

Coordinated ATC determination would imply taking into account the sum of flows in the entire system and determining the optimal solution from a system-wide perspective. This is what flow-based market coupling is expected to accomplish (see section 3.4.3).

Bidding zones facilitate more efficient solutions, but the *ex ante* adjustment of ATC values imply that loop and transit flows are prioritized in the grid, and do not "compete" for transmission capacity in the capacity allocation in line with scheduled flows (see Schavemaker and Beune, 2013)[5]. Although splitting the market in more bidding zones should provide more efficient market

[5] Schavemaker, P. H., and Beune, R. J. L.: Flow-Based Market Coupling and Bidding Zone Delimitation: Key Ingredients for an Efficient Capacity Allocation in a Zonal System. E-Bridge Consulting B. V.

prices and trade, it does not solve the main problem, namely that loop and transit flows are prioritized in the system, and do not have to compete for transmission capacity. Moreover the implication is that costs are borne by TSOs and market participants in other markets without proper compensation.

3.4.3 Flow-based market coupling

Flow based market coupling (FBMC) implies that ATC values are not defined separately before market clearing takes place. All flows between the defined nodes and on the represented interconnections will be determined simultaneously with commercial trades in the market algorithm and thereby included in the scheduled flows. With proper delimitation of bidding zones and flow-based market coupling, the entire system will be optimized simultaneously. FBMC implies that transit flows become part of the cross-border (between bidding zones) allocation mechanism, and appropriate market delimitation implies that problematic loop flows are "translated" to transit flows. FBMC applied to our simple model implies that even A is split into two bidding zones although a physical congestion is not expected within A. The point is to make sure that the scheduled flow within A is limited if that provides for the most cost effective solution from the market-wide perspective.

In our simple example, the generation in A west would probably not be affected when we assume that marginal costs are (very) low. However, the flow from A west to B1 would be fully scheduled and thereby a congestion rent would accrue on the entire physical flow on the interconnection. Prices should be adjusted accordingly, with the lower prices in A west, the higher prices in the bidding zones in B and the price in A east somewhere in between. The generation in A west would be prioritized in the grid only due to low marginal costs, but would now pay for access via the lower price in A west. The B1 bidding zone may still be "flooded" by cheap generation from A west, and prices would be lower than before.[6] Even with FBMC trade between two bidding zones can be reduced in order to accommodate flows elsewhere in the system ("implicit" ATC limitations).

FBMC requires adequate representation of the transmission grid in the market algorithm. Implicitly FBMC means to define (possible) bidding zones within systems and across systems. In an FBMC solution, all relevant grid connections should be clearly identified. All TSOs must submit adequate parameters for their grid configuration. Then the FB market algorithm would return the optimal physical and commercial transaction pattern. Prices in different zones and across borders should be optimal (or close to optimal). The smaller the bidding zones are, the more efficient solutions can be reached. In practice, however, it is hardly possible to fully represent the configuration of the grid in the market algorithm. Some are concerned that delimitation of bidding zones down to nodal pricing may have negative effects on competition and market liquidity. Such possible negative effects should be weighed against the benefits of more efficient price signals. Common guidelines for the representation of grid configuration and zone specification need to be developed.

Efficient FBMC will probably require moving the market more in the direction of nodal pricing, particularly as imbalances are likely to increase and flows to vary more over time due to the increase in renewable generation capacity.

A full-fledged flow based market coupling algorithm for the whole of Europe is not attainable in the short term, and is a long-term goal. The bidding zone delimitation must be weighed against the benefit of introducing FBMC over a larger area.

Although market-wide FBMC is likely to increase the overall efficiency of the system, it does not necessarily solve all distributional issues – particularly if these distributional issues are associated with an inadequate grid configuration.

[6] We recognize that the surplus of low cost, and perhaps intermittent generation in A west may increase system costs in the grid in B, but is situation may increase system

3.4.4 Expose renewable generation to market signals

Support schemes for renewable generation affect the short-term dispatch of renewable generation and the locational investment signals. Support schemes are typically designed to meet national targets (cf. the RES directive) and to utilize domestic resources. Since national targets are set in terms of energy delivered, support is usually paid in terms of production subsidies, sometimes combined with priority dispatch or indirect priority via exemptions from system costs, non-exposure to market prices and production subsidies.

To the extent that RES generation contributes to (or creates) loop and transit flows, short term loop flows may be reduced if RES generation is dispatched according to marginal costs, or may be curbed as part of system security. Although we do note that RES generation often has very low variable costs, and as such would probably primarily be curtailed in relatively severe situations. Sometimes however, the alternative to curbing wind or solar generation may be to incur very high start-stop costs in thermal power stations.

In the long term, the design of renewables targets and support schemes should be harmonized and developed in a way that accounts for the implications on market incentives, system operation and system development. Removal of direct and indirect priority dispatch would reduce challenges and system costs associated with loop and transit flows.

3.5 Long-term measures: Grid investments

Loop and transit flows can be regarded as a problem mainly when the share of unscheduled flows is large, i.e. when there is a large discrepancy between scheduled and physical flows. The impact of FBMC combined with improved bidding zone delimitation is to make scheduled flows more equal to physical flows. Another approach to reduce or limit loop and transit flows could be to make investments in the grid in order to make scheduled flows more equal to physical flows.

The focus of the European electricity system is shifting from a national supply focus to a European wide efficiency and decarbonizing focus. In order to realize efficiency gains from trade and system optimization, there is little doubt that the transmission grid needs to be strengthened. From a system-wide perspective the preferred grid investment may be internal in one system area and not on the system borders where the allocation of costs may be easier. In our example, that would imply increasing the transmission capacity in A in order to reduce the loop flow associated with scheduled flows within A. This is perhaps somewhat counterintuitive: Since the congestion occurs in B, it is easy to infer that the internal connection in B should be strengthened. Increasing the internal connection in B would however induce increased loop flows through B, and imply a further limitation in ATC values between A and B1.

Identifying the most beneficial grid investments from a European-wide perspective requires flow-based grid modelling in order to identify the critical lines. Without proper cost sharing mechanisms however, the optimal grid investments may not be realized. In our simple example, the TSO in A does not have an incentive to strengthen the internal grid since no congestion is observed. And the TSO in B will be reluctant to strengthen his grid, realizing that this may in turn increase loop flows and reduce cross-border congestion revenues.

In reality, the situation in the grid varies over time, and flows sometimes counteract each other and sometimes reinforce each other. Strengthening the grid in A may have other positive external effects. It is not easy to allocate costs and benefits of grid investments to different parties as the grid is inherently a natural monopoly with public good characteristics.

Investment in DC lines as the ones proposed in Germany is a special case of grid investment. The implication could effectively be to “move” generation from one grid area to another, i.e. from the area of the start node to the area of the end node of the DC line. As the flow on DC lines is controlled, in principle there would not be any loop flow associated with the flow on a DC line. However, directing flow in one area to the starting node and from the ending node in another area would affect flow patterns in the system.

3.6 Concluding remarks

The main problem with loop and transit flows is that they are implicitly prioritized in the electricity grid. With increased shares of location-specific and highly variable renewable generation in the system and a grid structure developed to accommodate more balanced and nationally focused generation and load structures, the amount of unscheduled flows in external control areas is likely to increase.

The discussion above indicates that the efficient solution to mitigate loop and transit flow problems from a market-wide perspective implies:

1. Flow-based market coupling and appropriate bidding zone delimitation
2. Coordinated grid development

If it is not possible to implement (full) FBMC, an alternative may be to introduce more bidding zones within control areas, to coordinate the determination of ATC values further and to find ways to compensate for loop and transit flow costs. Loop and transit flow costs are mainly related to redispatching and reduced congestion rents. We do realize that this is not an easy task, but at the same time it should be recognized that significant loop and transit flows may have very adverse effects on the benefits of trade and increased integration for some countries. An option that might be worth pursuing is to develop bilateral or regional mechanisms for cooperation and compensation to address these issues and to take such costs more accurately into account.

3.6.1 Summary of measures

We have discussed different types of measures available to handle a loop/transit flow problem within a control area, i.e. unscheduled flow creating a congestion or breach in security margins, using a simplified analytical framework. In the next chapter we explore market implications and test some of the hypothesis in a realistic market model.

The efficiency and allocation of costs and benefits differ according to the measures applied. The main conclusions/observations regarding other measures than FBMC and coordinated grid development are so far:

- Topology measures and PSTs may relieve the situation to some extent, but the scope is probably limited. Both topology measures and PSTs change the physical flow in the network and may “move” the loop flow problem elsewhere.
- Topology measures are often carried out unilaterally, but sometimes topology measures carried out in adjacent control areas can contribute and be more efficient.
- Redispatching may be very costly, and is typically carried out unilaterally by the host control area. It does not necessarily realize the optimal solution in terms of changes in generation and load profiles from a market-wide perspective. Long-term price signals are obscured.
- Countertrading distributes costs between TSOs but may not realize the optimal solution if mainly implemented as a cost sharing mechanism. Long-term price signals are obscured.
- Virtual PST agreements may include both countertrade and redispatching in addition to side payments. This may cater for a more efficient solution than pure redispatching and countertrade. However, none of the solutions provide the market with the proper price signals. Both the short-term and long-term efficiency in terms of price signals in the market are questionable.
- Unilateral reduction in ATC values may reduce redispatching costs in the host country, but it adversely affects incentives for trade and market integration.
- Bidding zone delimitation could alleviate the situation by exposing the market to more efficient price signals. In order for bidding zone delimitation to be effective, the delimitation should probably be regarded across a wider market area, and determination of ATC values

should be coordinated. Bidding zone delimitation primarily affects scheduled flows and does not remove the basic problem that loop and transit flows are prioritized in the grid.

- Grid expansion focusing on critical connections, i.e. connections where loop and transit flows frequently create congestions, would not necessarily be optimal. The result can be increased loop and/or transit flows.

In order to handle the challenges created by loop and transit flows in an efficient manner in the short and long term, it is important to develop a common understanding of the issues. Ongoing processes, e.g. to establish Virtual PST agreements, should yield a positive contribution in this respect.

The stepwise implementation of the IEM target models represent a transitional challenge, which is nevertheless important to address. Changes in the market design in one area or region may or may not have a beneficial effect on loop flows and costs in another area. An example is the claim that establishing Germany and Austria as one bidding zone has increased the loop flow challenges in Poland and the Czech Republic.

3.6.2 Distributional issues

When assessing proposed multilateral measures, it should be kept in mind that cost distribution may be one of the concerns addressed by the measure.

With unilateral handling of the congestion challenge the most cost effective alternatives may not be utilized as seen from the perspective of the wider system area. In smaller systems with weak grids, the internal resources may not be sufficient to handle large loop flows. Instead affected parties may agree to collectively apply countertrading in order to relieve particularly severe loop flow/congestion situations. As with unilateral non-market or TSO balancing measures, the locational signals will be muted by such practices. Such practices may also mute the incentives to strengthen the grid in the host country – which may be the preferred solution from a wider system perspective.

Issues related to the distribution of costs and benefits may be a significant obstacle to realize the most efficient measures. Returning to our simplified example, loop flows may be reduced by strengthening the internal grid in A or between B1 and B2. As long as the TSO in A does not experience severe internal congestions however, the incentive to strengthen the grid in A is weak.

If however the TSO in A must compensate the TSO in B for the costs, or if the TSO in B is able to divert the loop flows and by doing so increases the system costs in area A, it may become beneficial for the TSO in A to invest in the grid in order to increase the transmission capacity west-east in A. The TSO in B on the other hand will not have incentives to bear the cost of strengthening the internal grid and loses the cost compensation. The solution is to compensate grid investments undertaken to counter external flows as well. However, it is not possible to precisely allocate the costs between internal and external needs.

The existence of several TSOs complicates matters and creates challenges associated with information exchange, operational coordination and allocation of costs and benefits. A mechanism for allocating grid costs in Europe aimed to promote efficient investments and cooperation (making the European TSOs to act like one TSO) is probably required in order to address this issue.

4 QUANTITATIVE ANALYSIS

As part of the study we have conducted a quantitative analysis based on historical market data and physical flow data. We observe that loop and transit flows exist, and that there is sometimes a large deviation between scheduled flows and physical flows.[7] The historical analysis, based on data provided by European TSOs, aims at identifying potential causes for loop flows.

Using a power market model, we also assess different measures against loop flows. We find that price signals that reflect the physical bottlenecks in the system can improve the situation. Thus, bidding zone delimitation should be considered as a viable option. In addition, we find that some measures are potentially counteracted by potential market reactions, hence limiting their effectiveness. For example, a measure may impact spot market prices, which in turn influences generation in an area therefore also influences the effect of that measure. Instead of interfering with the market, one should therefore consider a market based solution that improves generation and trade decisions in the first place instead of trying to reduce the problem *ex-post*.

Limitations of the study: *We have not applied a physical grid model in this study. Hence, in our analysis we cannot conclude with certainty what actually causes loop flows. Furthermore, we cannot conclude with certainty that the measures analysed will in fact resolve the loop flow problems. Again, this would require a full physical grid model for the European power system. Nevertheless, we find that the indications for what actually causes the loop flows and what may resolve the associated problems are fairly strong.*

4.1 Historical empirical analysis

4.1.1 Data overview

To identify and quantify loop flows, we have conducted an empirical analysis. For the empirical assessment, 16 TSOs have supplied hourly data on ATC values, scheduled flows, physical flows, flow on critical branches, demand, prices, and wind, photovoltaic and total generation. The data supplied covers the years 2011 and 2012. Figure 6 shows an overview of the countries from which we have received data. For Germany we have received data from all four TSOs. We have received data on physical flow on critical branches from the following TSOs: PSE, Elia, ČEPS, ELES, and APG. Both PSE and Elia have supplied indicative critical limits on the branches. Additionally we have received French, German and Polish data on physical flows within France, within Germany and within Poland.

Figure 6: Data coverage of the historical analysis (highlighted in green)

[7] A similar assessment has previously been conducted by the TSOs in CEE (*Unscheduled flows in the CEE region* by Ceps, Mavir, PSE and SEPS, 2013).

Each TSO has supplied data on its cross-border flows. This implies that some data was supplied twice, once by each relevant TSO. For example, flow between Germany and Poland was reported both by 50Hertz and by PSE.

Table 1 summarizes which source we have used for which cross-border line flow data. If both respective TSOs are named as data source, then their data matches. However in our analysis we have observed that the data does not match completely in all instances. We therefore also added comments on lines with large deviations between the respective datasets. The reason for the deviations may be different methods and scopes for measuring and reporting scheduled and physical flows. When we have chosen one particular data set above another, it's due to known directions and magnitudes from similar assessments or so that the net sum of unscheduled flows to and from the zone zeroes out.

Table 1: Sources used for flow data

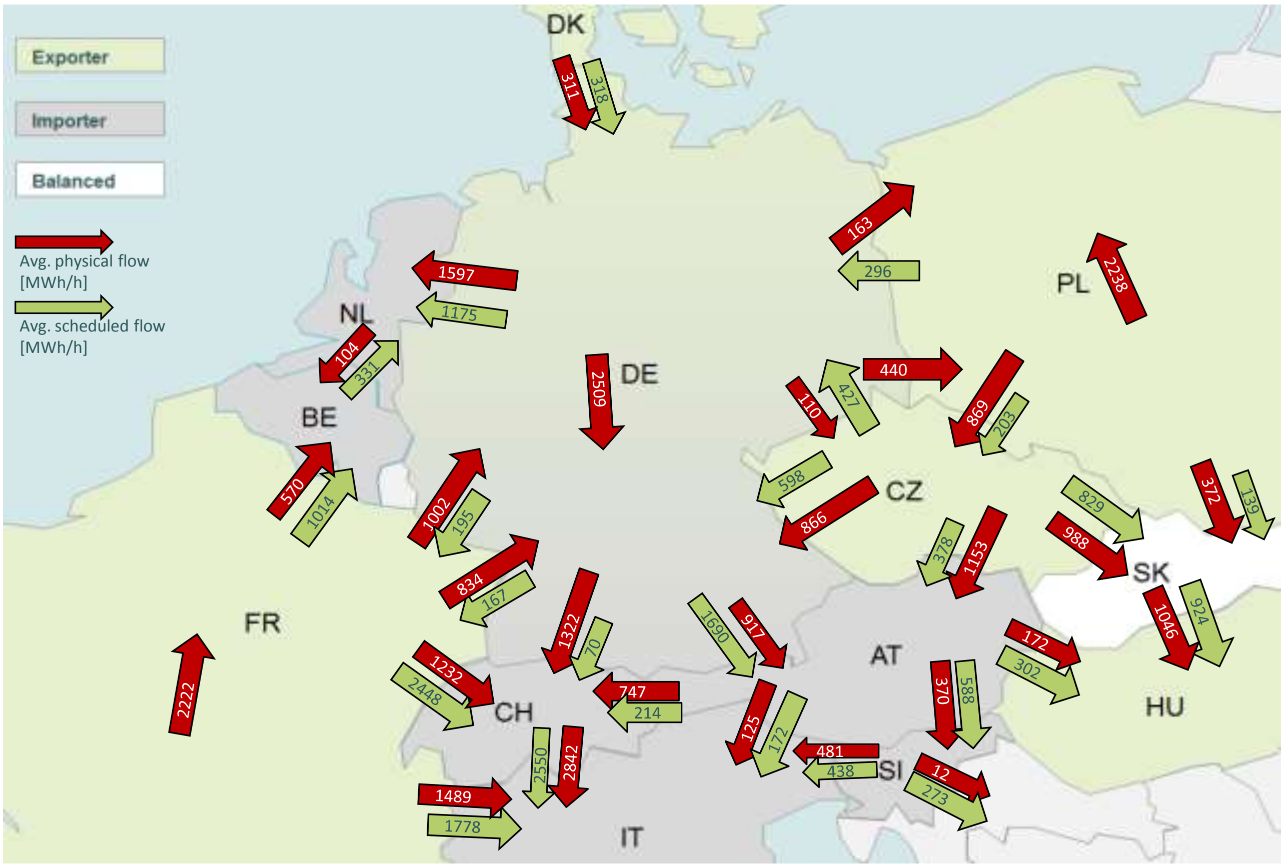
Cross-border	Data source(s)	Comment
DK – DE	TenneT, Energinet.dk	Excluding the DC Kontek cable
DE – NL	Amprion, TenneT GmbH, TenneT	
NL – BE	Elia, TenneT	Minor differences between the two
BE – FR	Elia	RTE data have higher scheduled values
DE – FR	TransnetBW, Amprion	Data per control area from the Germans TSOs
FR – CH	RTE, SwissGrid	
FR – IT	TERNA	RTE schedule is higher
DE – CH	Vulcanus database	German data through TransnetBW and Amprion from Vulcanus database. SwissGrid physical somewhat lower.
CH – IT	SwissGrid, TERNA	
DE – AT	APG	Tennet GmbH data is lower
AT – IT	APG, TERNA	
IT – SI	TERNA, ELES	
AT – SI	APG, ELES	
SI – HR	ELES	
AT – HU	APG, MAVIR	
AT – CH	APG	SwissGrid higher, both physical and scheduled
CZ – AT	CEPS, APG	
CZ – SK	CEPS	SEPS data being lower, both physical and scheduled
SK – HU	MAVIR	Minor differences and opposite direction from SEPS
PL – SK	PSE	SEPS data is lower, both physical and scheduled
PL – CZ	PSE, CEPS	
DE – PL	50Hertz, PSE	
DE – CZ	50Hertz, CEPS	
DE North – South	All German TSOs	Amprion, Tennet GmbH, TransnetBW, 50Hertz
PL North – South	PSE	Aggregated from data for individual lines
FR North – South	RTE	

4.1.2 Overview of unscheduled flows and potential loop flows

In this section we give an overview of historical scheduled flows, physical flows and unscheduled flows. As a reminder, unscheduled flows are defined as the difference between actual physical flows and the scheduled (market) flows.

Figure 7 shows 2-year hourly averages of physical and scheduled flows on the respective borders, based on the hourly data provided.

Figure 7: Average physical and scheduled flows [MWh/h], 01.01.2011 – 31.12.2012

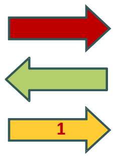
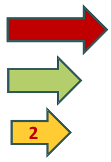
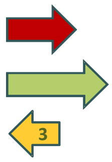


Source: THEMA Consulting Group, based on data from 16 TSOs

Notably, Figure 7 shows some large deviations between physical and scheduled flows on some cross-border sections. For example, on the German-Polish border, scheduled and physical flows do not only deviate in magnitude, but go into opposite directions. On other cross-border sections, as for example Germany-Netherlands, the flows go in the same direction, but differ in magnitude.

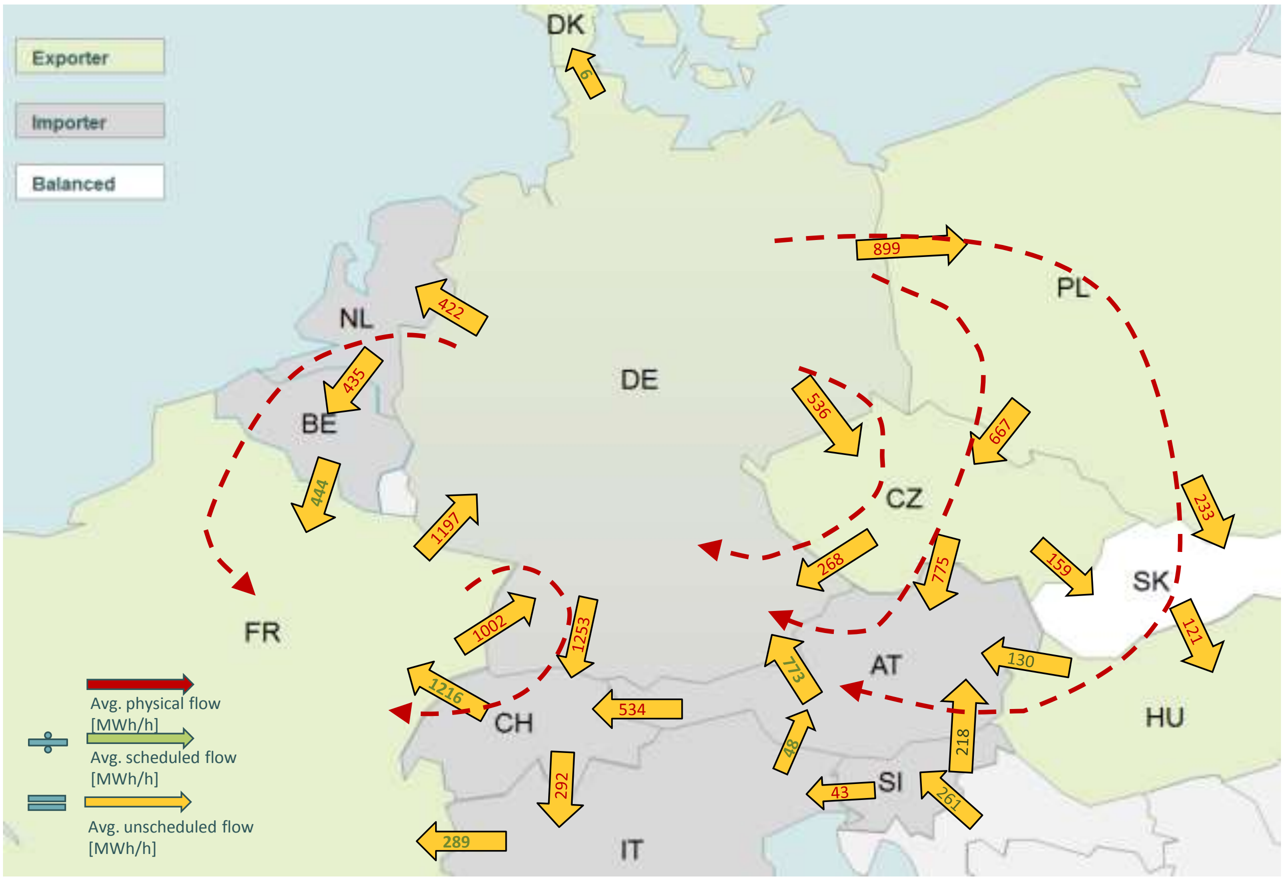
All things considered, we can identify three different types of unscheduled flows: physical and scheduled flows may go in opposite directions, or they are aligned, but have different magnitude. In the latter case, one can distinguish between physical flows that exceeds the scheduled flow or vice versa. A summary of the cases is given in Table 2.

Table 2: Principle types of unscheduled flows

Physical flow and scheduled flow in the opposite direction. Examples include the German-Polish cross section, and FR-DE, BE-NL, and DE-CZ. The unscheduled flow goes in the same direction as the physical flow.	Physical Scheduled Unscheduled 
Physical flow and scheduled flow in the same direction, and physical flow exceeding scheduled flow. An example is the German-Dutch cross section. The unscheduled flow goes in the same direction as the physical flow.	Physical Scheduled Unscheduled 
Physical flow and scheduled flow in the same direction, and scheduled flow exceeding physical flow. An example is the German-Austrian cross-border section. The unscheduled flow goes in the opposite direction of the physical flow.	Physical Scheduled Unscheduled 

The average unscheduled flows, corresponding to the physical and scheduled flows in Figure 7, are shown in Figure 8. The font colours of the unscheduled flow indicate what type of unscheduled flow it is, according to Table 2 above. The figure also indicates annual country balances; i.e. which countries are net exporters and importers of electricity in 2011 and 2012 (average). In Central Western Europe (CWE), the Netherlands and Belgium are net importers, while France exports. In Central Southern Europe (CSE), both Switzerland and Italy are net importers. In Central East Europe (CEE) the Czech Republic, Poland and Hungary are net exporters, while Austria imports. Germany is a net exporter. For Germany the surplus is, as indicated, distributed unevenly between the north and south.

Figure 8: Average unscheduled flows for the years 2011 and 2012, MWh/h[8]



Source: THEMA Consulting Group, based on data from 16 TSOs

In this report, we focus on three different cases of loop and transit flows, indicated in Figure 8: loop flows in Central Eastern Europe, involving Germany, Poland, Czech Republic and Austria, transit flows in Central Western Europe, involving Germany, the Netherlands, Belgium, and France, and a loop flow in Central South Europe, where we identify a loop flow from France through Germany and Switzerland, back to France. These flows are analysed in more detail in the following section.

The loop and transit flows are identified visually (cf. Figure 8) and by analysing how well the individual unscheduled flows are correlated with each other. A further discussion on the identification of the loops can be found in section 4.1.3.

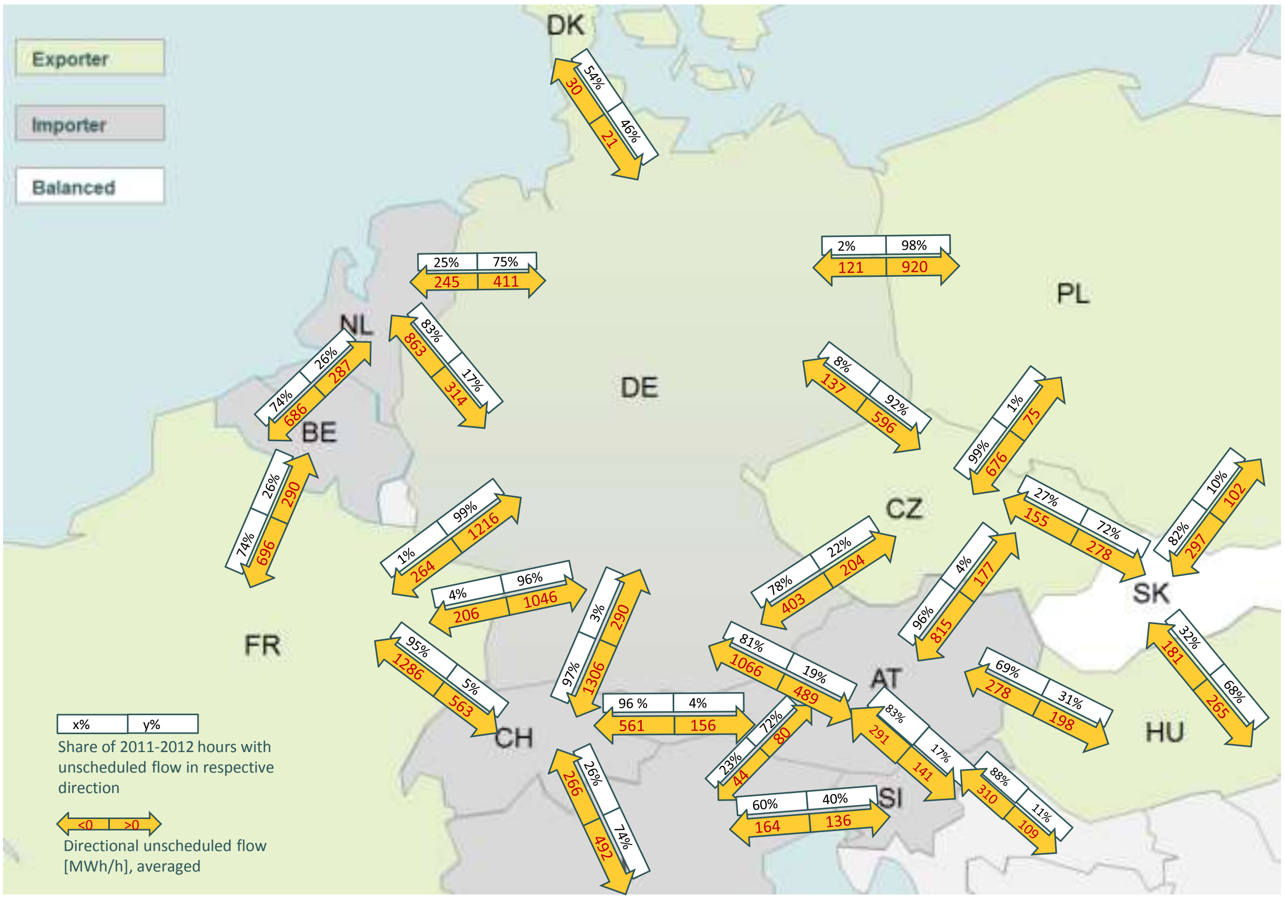
Please note that the indicated flows in Figure 8 are two-year averages, implying that flow patterns in individual hours, periods or seasons could look quite different. Looking only at averages can therefore be misleading, especially if the unscheduled flows change direction through the year, implying that they contribute to nullify each other when considering the average.

We therefore also accounted for the direction of the unscheduled flow, and extended the analysis by distinguishing the direction of the unscheduled flow. The results are shown in Figure 9, showing the average unscheduled flow split in both cross-border directions. Thus, the figure shows the average unscheduled flow for all those hours in which the unscheduled flow goes in the same direction. The figure also shows the number of hours in which the deviation occurred as a percentage of the total hours in the dataset (2011-2012). This distinction between the directions of

[8] Figure 8: Red numbers where physical flow is in the opposite direction or larger than scheduled flow, green number if it is less than scheduled flow, see Table 2.

the unscheduled flows confirms the loop flows identified above. Furthermore, they show that unscheduled flows also occur on cross-border sections where they are not visible when simply looking at the averages as shown in Figure 8.

Figure 9: Average directional unscheduled flow in MWh/h, and share of hours with unscheduled flow in respective direction, for the 2-year period 2011-12.



Source: THEMA Consulting Group, based on data from 16 TSOs

4.1.3 Case studies

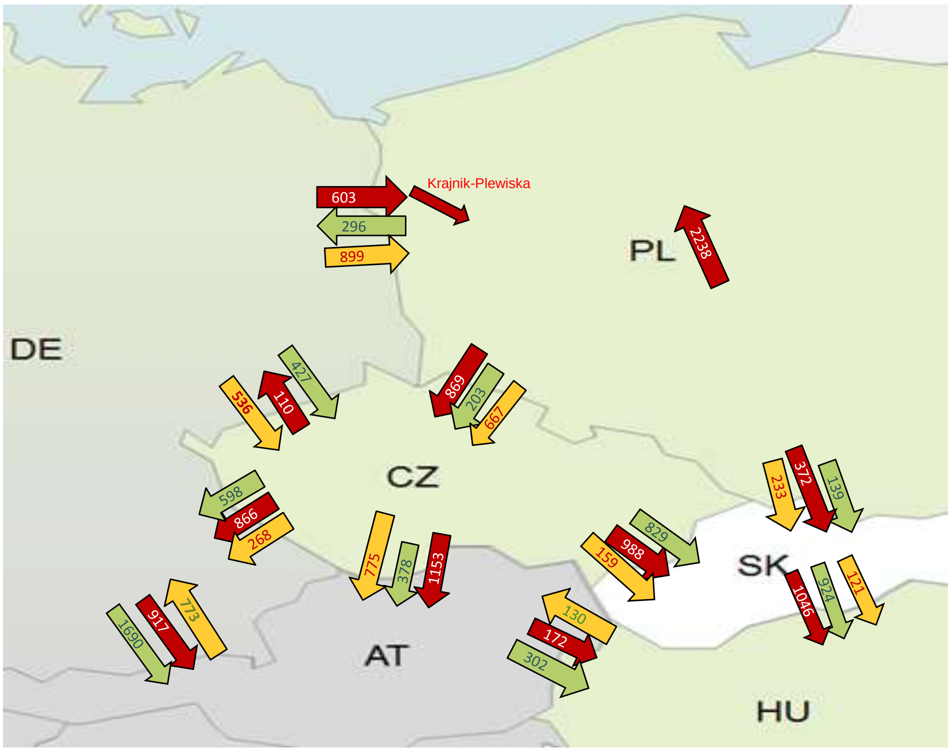
In order to investigate the causes of different loop flows, to look into the challenges associated with them, and to test measures to mitigate the challenges caused by loop flows, we looked more closely into the three loop flows identified above. Thus, we are looking at the loop flows in the following regions:

- Central East Europe (Case 1)
- Central West Europe (Case 2)
- Central South Europe (Case 3)

Case 1: Loops in Central East Europe

We find strong loop flow indications that involve Germany, Poland, Czech Republic, and other countries in Central East Europe. Furthermore, both Poland and Czech Republic reported critical instances on internal lines over the analysed time period. Figure 10 gives a more detailed depiction of the deviations between scheduled flows and physical flows in this region.

Figure 10: Average physical (red), scheduled (green) and unscheduled (yellow) flows in the indicated eastern loop.



Source: THEMA Consulting Group, based on data from 16 TSOs

We also find strong correlations between unscheduled flows, and that they occur simultaneously, creating a real loop flow. This is reflected by the figures presented in Table 3, showing the overall percentage of hours in which the unscheduled flow occurred, and to what extent the unscheduled flows happened simultaneously. The assessment shows that the Central East loop DE-PL-CZ-AT-DE occurs in 81 per cent of the hours in the 2-year period investigated. By assessing the parts of the loop flow, i.e., the transit DE-PL-CZ-AT, we find it to be intact in 95 per cent of the hours.

Table 3: Assessment of the Central East Europe loop flow

Cross-border	2-year average unscheduled flow (MWh/h)	2-year average unscheduled flow in the "loop" direction	Hours with unscheduled flow in the "loop" direction	Comments
DE(50Hertz)-PL	899	920	98 %	Unscheduled flow in the direction of the physical flow
PL-CZ	667	676	99 %	Unscheduled flow in the direction of the physical flow
CZ-AT	775	815	96 %	Unscheduled flow in the direction of the physical flow
AT-DE(TenneT)	773	1066	81 %	Unscheduled flow in the opposite direction of the physical transit flow.
Total	**667**[a]	-	**80 %**[b]	**Major share of hours where the loop flow is intact**

[a] The minimum of the involved unscheduled flows in the loop
[b] Share of hours where the unplanned transit DE-PL-CZ-AT-DE is intact

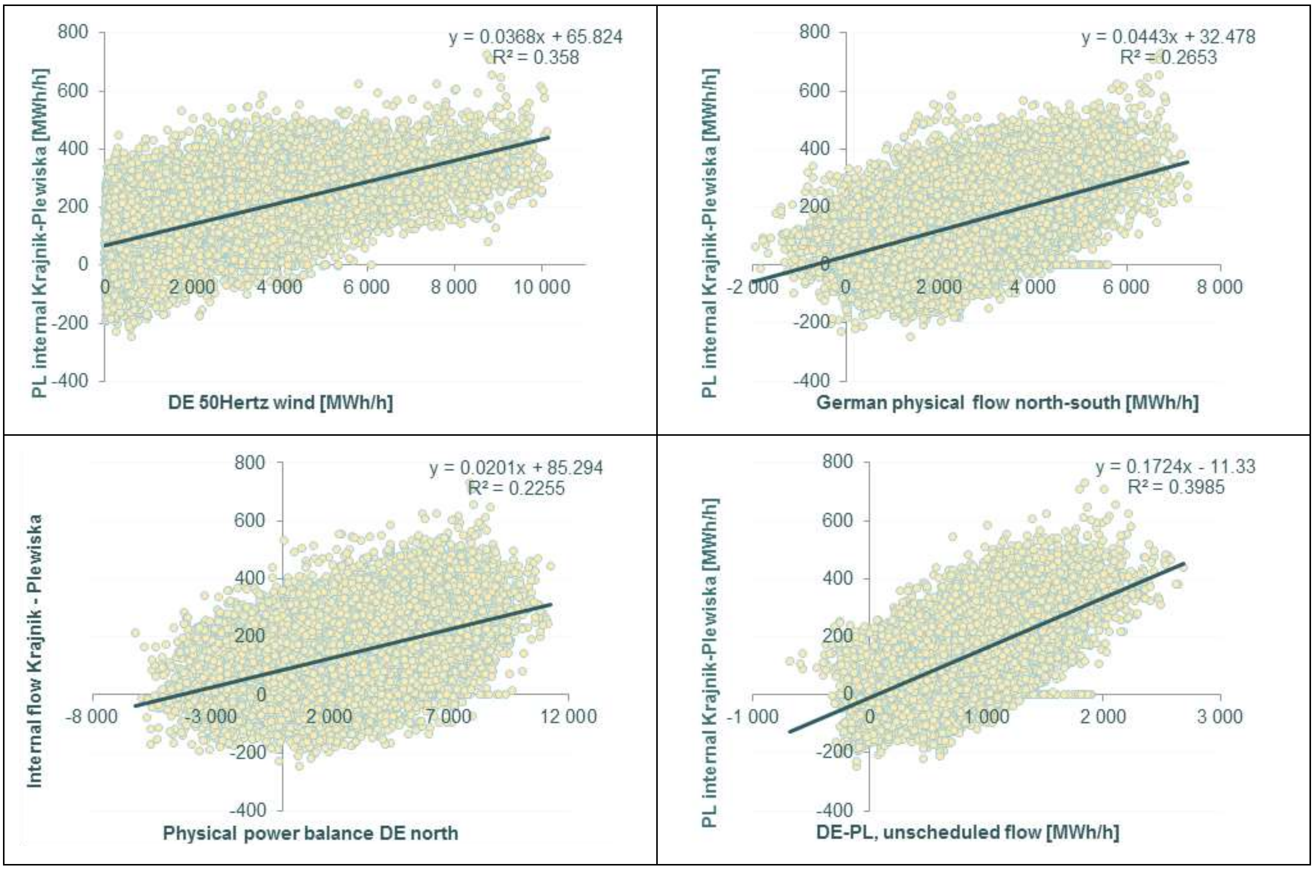
One of the challenges associated with loop flows seems to be the large deviation between physical and scheduled flows on the Polish-German cross section. While large physical flows cross the border in direction of Poland, price signals (or commercial agreements) actually lead to scheduled flows in the other direction. When we also consider data on lines within Poland, we can make the following observations:

- The load on internal critical branches in Poland is positively correlated with wind feed-in in northern Germany.
- The load on internal critical branches in Poland is positively correlated with internal physical north-south flows in Germany.
- The load on internal critical branches in Poland is positively correlated with surplus in northern Germany.
- The load on internal critical branches in Poland is positively correlated with unscheduled flow on the German-Polish cross section.
- The unscheduled flows on the German-Polish cross section are positively correlated with wind feed-in in northern Germany.
- There is a positive correlation between unscheduled flows Germany to Poland and scheduled flow between Austria and Germany.

The respective correlations are depicted in Figure 11 and Figure 12 and summarized in the correlation matrix of Table 4.[9] While we cannot conclude on the causes underlying loop flows, the renewable feed-in in Germany, in connection with internal flows within Germany, seems to be relevant variables in this context, as they are strongly correlated with the unscheduled flows on the German-Polish border.

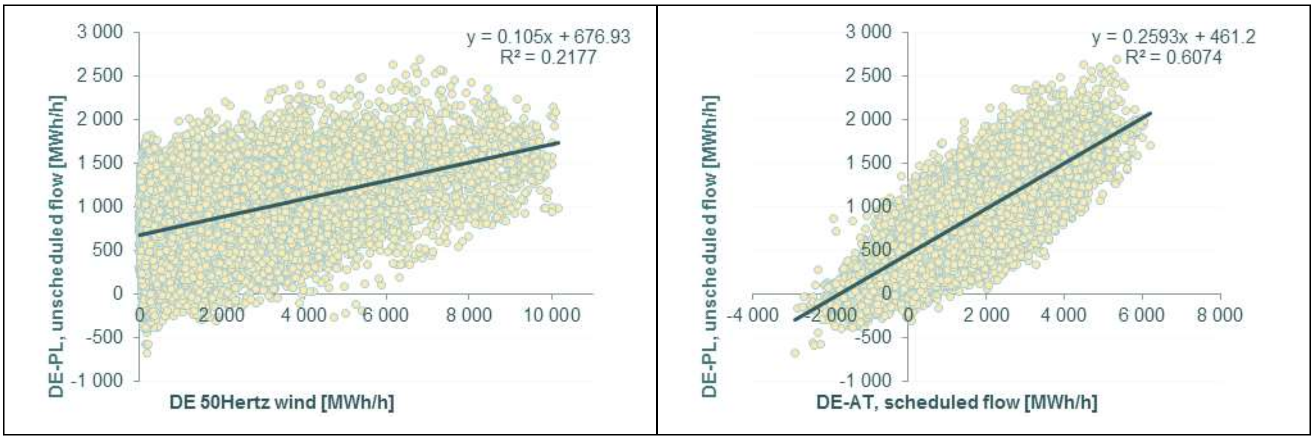
[9] Note that when we are doing a linear regression with only one explanatory variable the coefficient of determination, R^2, is simply the square of the sample correlation coefficient. That is, the correlation matrix of Pearson's correlation coefficients will simply show the square root of R^2, i.e. R.

Figure 11: Internal Polish flow on Krajnik-Plewiska versus selected variables (plotted for 2-year period 2011-2012; all measured in MWh/h)



Source: THEMA Consulting Group, based on data from 16 TSOs

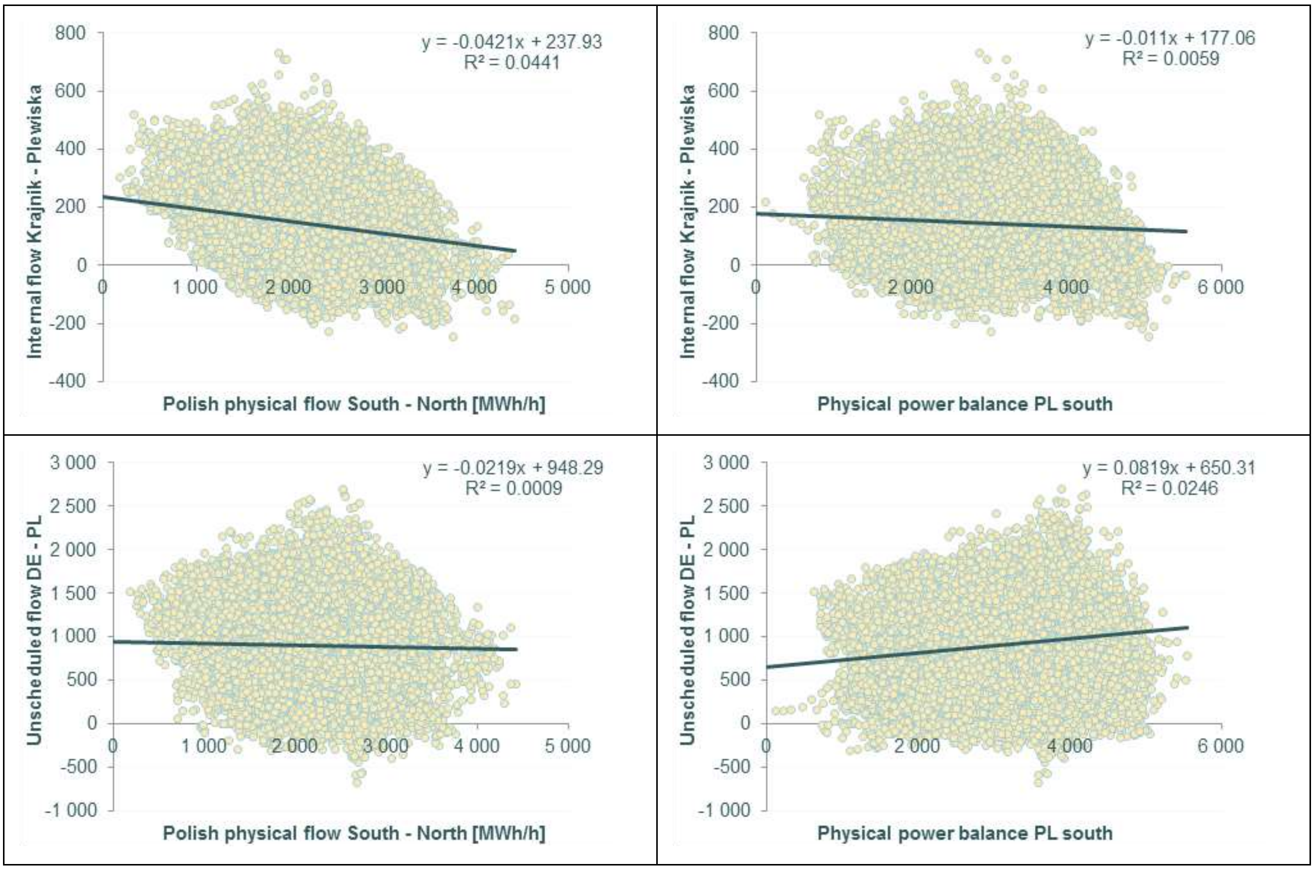
Figure 12: Unscheduled flow between Germany and Poland versus selected variables (plotted for 2-year period 2011-2012; all measured in MWh/h)



Source: THEMA Consulting Group, based on data from 16 TSOs

We also investigated Polish physical flow (south-north) and the physical power balance in southern Poland in order to see whether they have some explanatory value. The results are shown in Figure 13. We find that these two variables have limited explanatory value regarding flow on critical lines in Poland and the unscheduled flow between Germany and Poland.

Figure 13: Polish internal physical flow and power balance versus selected variables (plotted for 2-year period 2011-2012; all measured in MWh/h)



Source: THEMA Consulting Group, based on data from 16 TSOs

Table 4: Matrix of correlation coefficients for variables concerning Case 1

	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*	*[11]*	*[12]*	*[13]*
DE-PL unsched. *[1]*	1.00	**0.90**	**0.79**	0.58	0.33	**0.76**	0.62	0.50	0.00	0.63	0.03	0.16	0.47
PL-CZ unsched. *[2]*	**0.90**	1.00	**0.71**	0.43	0.30	0.67	0.56	0.39	-0.01	0.54	-0.05	0.22	0.42
CZ-AT unsched. *[3]*	**0.79**	**0.71**	1.00	0.66	-0.05	**0.85**	0.45	0.39	0.06	0.61	0.11	0.02	0.40
50Hertz-CZ unsched. *[4]*	0.58	0.43	0.66	1.00	0.41	0.55	0.67	0.63	-0.02	0.60	0.27	-0.10	0.59
CZ-DE unsched. *[5]*	0.33	0.30	-0.05	0.41	1.00	-0.09	0.58	0.42	-0.15	0.27	0.14	-0.03	0.45
AT-DE unsched. *[6]*	**0.76**	0.67	**0.85**	0.55	-0.09	1.00	0.36	0.25	-0.08	0.53	-0.09	0.21	0.30
DE North-South flow *[7]*	0.62	0.56	0.45	0.67	0.58	0.36	1.00	0.65	-0.38	0.52	0.19	0.08	0.57
DE North balance *[8]*	0.50	0.39	0.39	0.63	0.42	0.25	0.65	1.00	0.03	0.47	0.20	-0.11	0.56
DE South balance *[9]*	0.00	-0.01	0.06	-0.02	-0.15	-0.08	-0.38	0.03	1.00	-0.08	0.15	-0.20	-0.09
Critical line Poland *[10]*	0.63	0.54	0.61	0.60	0.27	0.53	0.52	0.47	-0.08	1.00	0.21	-0.08	0.60
PL North-South flow *[11]*	0.03	-0.05	0.11	0.27	0.14	-0.09	0.19	0.20	0.15	0.21	1.00	**-0.83**	0.41
PL South balance *[12]*	0.16	0.22	0.02	-0.10	-0.03	0.21	0.08	-0.11	-0.20	-0.08	**-0.83**	1.00	-0.23
DE(50Hertz) wind *[13]*	0.47	0.42	0.40	0.59	0.45	0.30	0.57	0.56	-0.09	0.60	0.41	-0.23	1.00

Source: THEMA Consulting Group, based on data from 16 TSOs

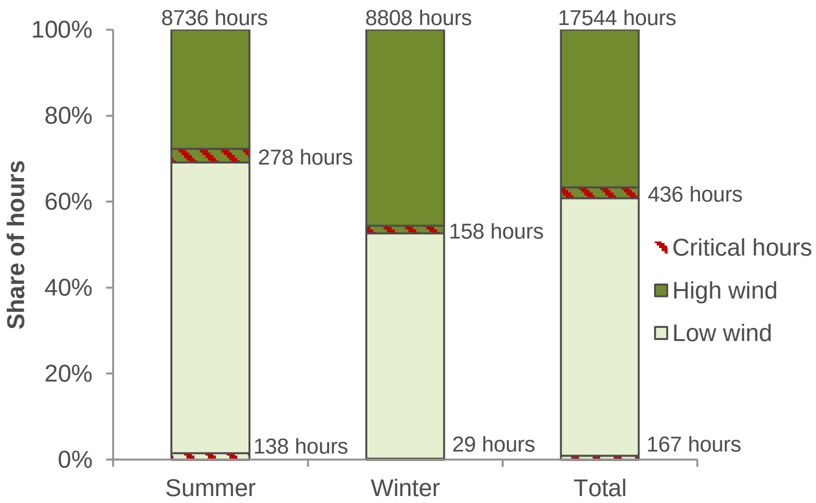
As scheduled flows are a result of market prices and price differences, it seems that the prices in Germany seem to trigger cross-border market flows that are not in line with the physical flows.

Bottlenecks within Germany are not reflected in the prices, as Germany does not apply bidding zone delimitation. The observations indicate that prices in northern Germany are higher than they should be – triggering higher generation in northern Germany, but also higher generation in Poland destined for market exports to Germany. In the south of Germany, prices seem to be too low; triggering lower generation than what is optimal from a cross-border and local balance point of view.

Thus, the absence of bidding zones does not only affect internal dispatch in Germany, but also cross-border trade and generation in neighbouring countries, which in turn amplifies the overall loop flow problem.

The strong correlation between wind feed-in in Germany and critical load on internal branches in Poland is also illustrated in Figure 14. The Polish TSO, PSE, has supplied their indicative security thresholds for the total cross-border flow between Poland and the 50Hertz control area. When this threshold is exceeded, an insecure situation on the DE-PL border becomes very probable. Figure 14 shows the number of hours in 2011 and 2012 when these thresholds have been breached. We see that critical loads are more frequent in the summer, in particular when the wind feed-in is high.

Figure 14: Hours with exceeded indicative thresholds at DE-PL border; split by season and whether wind production is high or low.[10]



Source: THEMA Consulting Group, based on 2011-2012 data from 50Hertz and PSE.

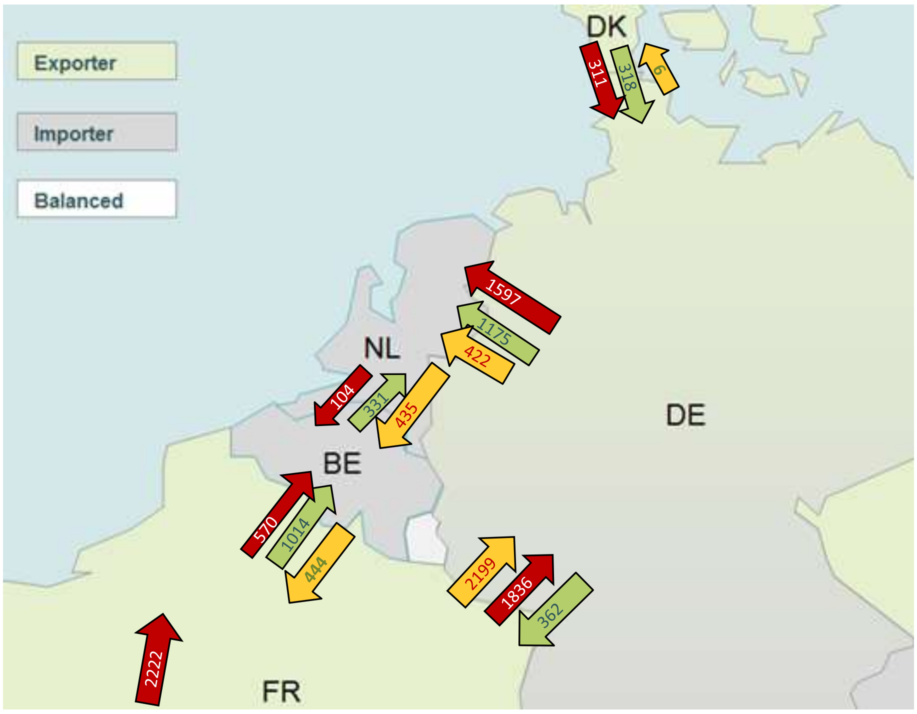
Case 2: Transit flows in Central West Europe

On the Western side of Germany, we find indications of a loop flow involving Germany, the Netherlands, Belgium, and France. While scheduled and physical flows point in the same direction, we find substantial deviations between physical and scheduled flows (see Figure 15). This is particularly the case for the Dutch-German border.

---

[10] The indicative thermal thresholds are 1600 MW during winter and 1300 MW during summer. High wind means more than 20% of 2011-2012 max in 50Hertz, i.e. hours with more than 1999 MWh/h of wind production.

Figure 15: Average physical (red), scheduled (green) and unscheduled (yellow) flows in the indicated western transit [MWh/h]



Source: THEMA Consulting Group, based on data from 16 TSOs

The numbers in Table 5 indicate that the unscheduled flows occur simultaneously, hence creating a real transit from Germany to France. In the 2-year period we are assessing, the transit flow is intact 68 % of the hours.

Table 5: Assessment of the western transit flow

Cross-border	2-year average total unscheduled flow (MWh/h)	2-year average unscheduled flow in the “loop” direction	Hours with unscheduled flow in the “loop” direction	Comments
DE-NL	422	706	74 %	Average unscheduled flow in the opposite direction of physical flow.
NL-BE	435	686	74 %	Unscheduled flow in the direction of the physical loop
BE-FR	444	696	74 %	Average unscheduled flow in the opposite direction of physical flow.
Total	**422** [a]	-	**68 %**	**Large share of hours where the transit is intact**

[a] The minimum of the involved unscheduled flows in the loop, for DE-NL we used the net flow of the two lines

In this case, however, we do not find clear correlations. Overall, we find the following:

- Positive, but weak correlation between unscheduled flows and wind feed-in in Germany.
- Positive, but weak correlation between unscheduled flows and internal the flow in Germany.

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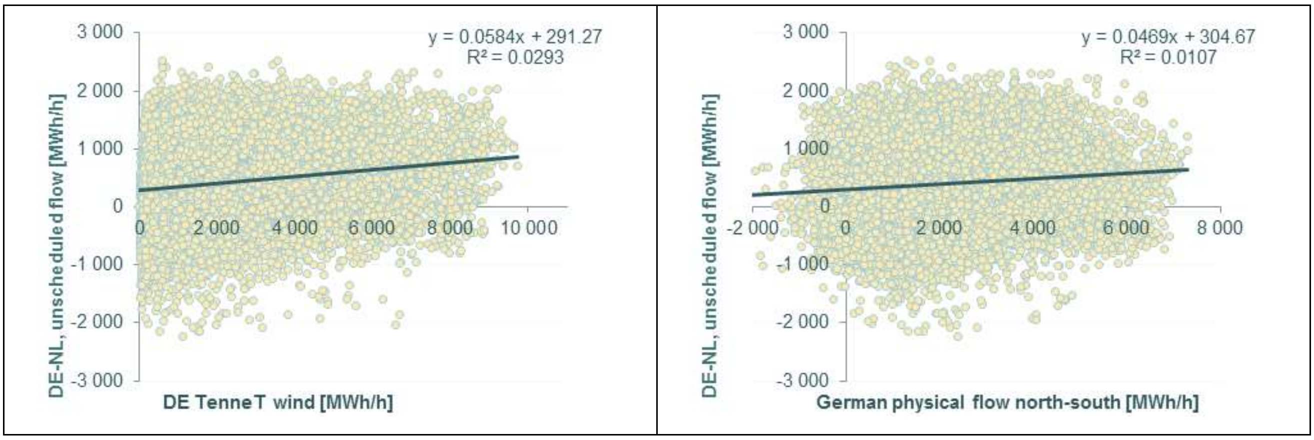
- Overall strong positive correlation between the unscheduled flows on the German-Dutch, Dutch-Belgium, and Belgium-France cross sections.
- Positive, but weak correlation between the unscheduled flow between Germany and France, and the other unscheduled flows.

Some illustrations regarding these correlations are found in Figure 16, a correlation matrix for the variables can be found in Table 6.

Figure 16: Unscheduled flows between Germany and the Netherlands vs. German wind production and internal flow (plotted for 2-year period 2011-2012; all measured in MWh/h)



Source: THEMA Consulting Group, based on data from 16 TSOs

Table 6: Matrix of correlation coefficients for variables concerning Case 2

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
DE-NL unsched. [1]	1.00	**0.87**	**0.86**	0.33	0.10	-0.23	0.17	-0.36
NL-BE unsched. [2]	**0.87**	1.00	**0.99**	0.43	0.11	-0.29	0.20	-0.38
BE-FR unsched. [3]	**0.86**	**0.99**	1.00	0.43	0.11	-0.28	0.20	-0.39
FR-DE unsched. [4]	0.33	0.43	0.43	1.00	0.30	0.20	0.18	-0.06
DE North-South flow [5]	0.10	0.11	0.11	0.30	1.00	0.22	0.59	0.28
FR North- South flow [6]	-0.23	-0.29	-0.28	0.20	0.22	1.00	0.10	0.13
DE Wind (TenneT) [7]	0.17	0.20	0.20	0.18	0.59	0.10	1.00	-0.02
BE thermal gen. [8]	-0.36	-0.38	-0.39	-0.06	0.28	0.13	-0.02	1.00

Source: THEMA Consulting Group, based on data from 16 TSOs

Overall, finding the causes underlying this loop flow is challenging, perhaps due to the fact that the involved TSOs already apply PSTs. Hence, the physical flows observed are already impacted by correcting measures. Furthermore, none of the TSOs in this region reported any critical loads on internal branches. Thus, to what extent this transit actually causes challenges cannot be answered with the data available to us in this study.

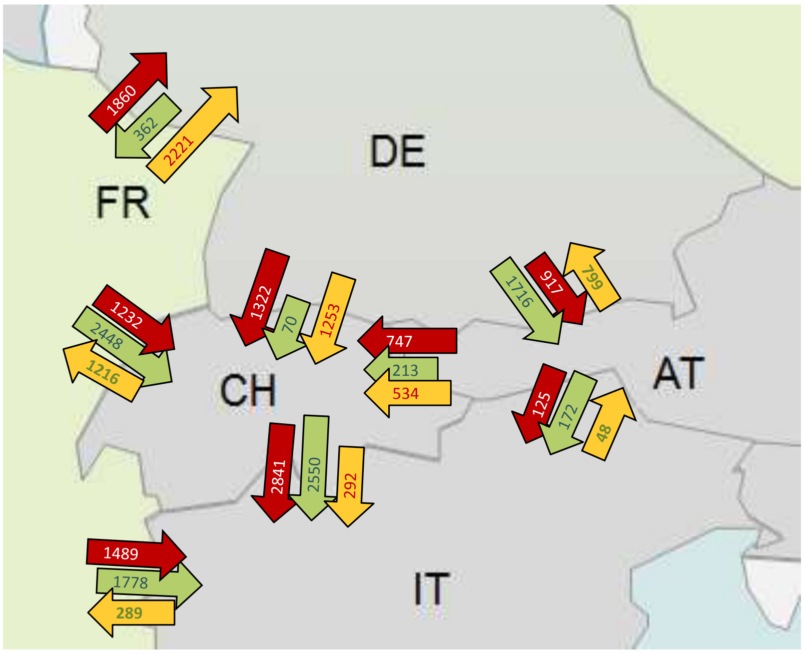
Nevertheless, it seems that prices in (northern) Germany trigger market exports that are too low. With lower prices in northern Germany, scheduled flows in direction of the Netherlands/Belgium are likely to increase. At the same time, lower prices are likely to reduce generation in northern Germany, hence reducing the physical flow from Germany into the Netherlands.

Case 3: Loop flows in Central South Europe

The last indicated loop involves France, Germany and Switzerland. Especially between Germany and France we see a significant deviation between scheduled and physical flows (see Figure 8).

The same applies for the German-Swiss cross-border section. It should be noted, though, that neither of the involved TSOs reported any grid challenges related to this loop flow.

Figure 17: Average physical (red), scheduled (green) and unscheduled (yellow) flows in the indicated south-western loop [MWh/h]



Source: THEMA Consulting Group, based on data from 16 TSOs

In Table 7 we summarize an assessment of the south-western loop flow. The loop flow FR-DE-CH-FR is intact in 94 per cent of the hours in the 2-year period investigated, which indicates that the unscheduled flows occur simultaneously. If one only considers the transit FR-DE-CH, we find that it occurs in 97 per cent of the hours in the studied time period.

Table 7: Assessment of the south-western loop flow

Cross-border	2-year average total unscheduled flow (MWh/h)	2-year average unscheduled flow in the "loop" direction	Hours with unscheduled flow in the "loop" direction	Comments
FR-DE	2198	2223	99,9 %	Unscheduled flow in the direction of the physical flow
DE-CH	1253	1306	96,6 %	Unscheduled flow in the direction of the physical flow
CH-FR	1216	1286	95,3 %	Average unscheduled flow in the opposite direction of physical flow.
Total	**1216** [a]	-	**94 %**	**Loop is intact in nearly the entire analysis period**

[a] The minimum of the involved unscheduled flows in the loop. For FR-DE we used the total flow of the two lines

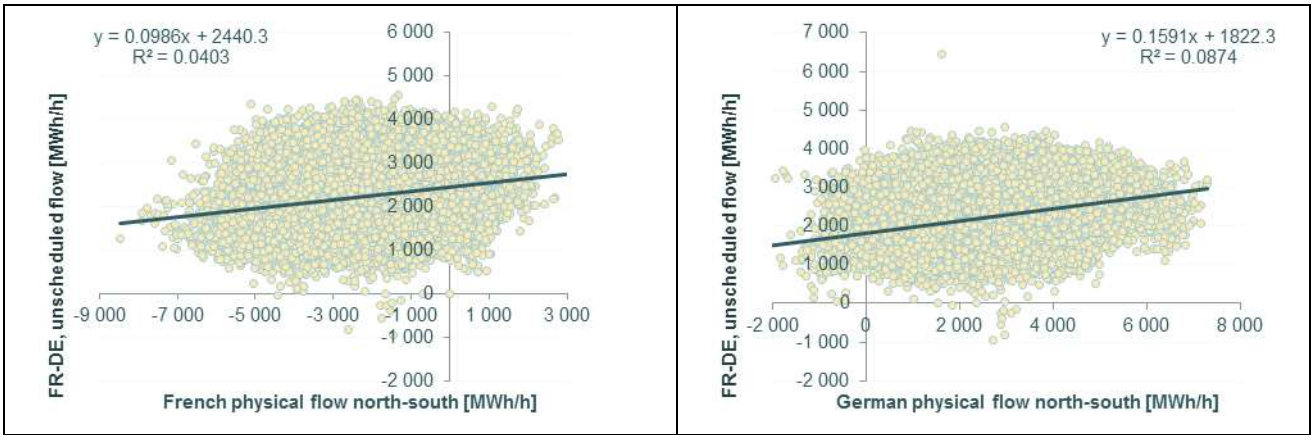
By also investigating correlations we try to find explanatory variables to the loop and transit flows. In this case, we find that the unscheduled flows in the loop flow are moderately correlated. The strongest correlation is found between flows from CH to FR and from DE to CH.

It is challenging to find obvious variables explaining the unscheduled flows. However, the following observations can be made:

- Positive correlation between the unscheduled flows in the indicated loop/transit and north-south flows internally in France. The unscheduled flows between France and Germany are positively correlated with north-south flows internally in Germany.
- Weak correlation between unscheduled flows and wind feed-in in Germany.
- Some correlation between unscheduled flows and wind feed-in in France.
- Unscheduled flow between France and Germany is correlated with unscheduled flow between France and Italy.

Some illustrations regarding these correlations are found in Figure 18. A correlation matrix for the variables can be found in Table 8.

Figure 18: Unscheduled flows between France and Germany vs. French and German internal north-south flows (plotted for 2-year period 2011-2012; all measured in MWh/h)



Source: THEMA Consulting Group, based on data from 16 TSOs

Table 8: Matrix of correlation coefficients for variables concerning Case 3

	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*
FR-DE unsched. [1]	1.00	0.46	0.35	0.20	0.30	0.12	0.00	-0.44
DE-CH unsched. [2]	0.46	1.00	0.68	0.44	0.24	0.03	0.20	-0.26
CH-FR unsched. [3]	0.35	0.68	1.00	0.30	0.01	-0.07	0.18	-0.01
FR north-south flow [4]	0.20	0.44	0.30	1.00	0.17	-0.04	0.61	-0.27
DE north-south flow [5]	0.30	0.24	0.01	0.22	1.00	0.24	-0.16	-0.28
FR Wind [6]	0.12	0.03	-0.07	-0.04	0.18	1.00	0.04	-0.07
French north balance [7]	0.00	0.20	0.18	0.61	-0.25	0.04	1.00	0.18
FR-IT unsched. [8]	-0.44	-0.26	-0.01	-0.27	-0.31	-0.07	0.18	1.00

Source: THEMA Consulting Group, based on data from 16 TSOs

4.1.4 Summary of observations

All things considered, we find several examples of unscheduled flows. We also find examples for all three types of unscheduled flows, i.e. that scheduled and physical flows go in opposite directions, that physical flow exceeds scheduled flow, or that scheduled flow exceeds physical flow.

The cases described above involve Germany and its neighbouring countries. However, it should be noted that unscheduled flows are a general phenomenon, not confined to the German borders.

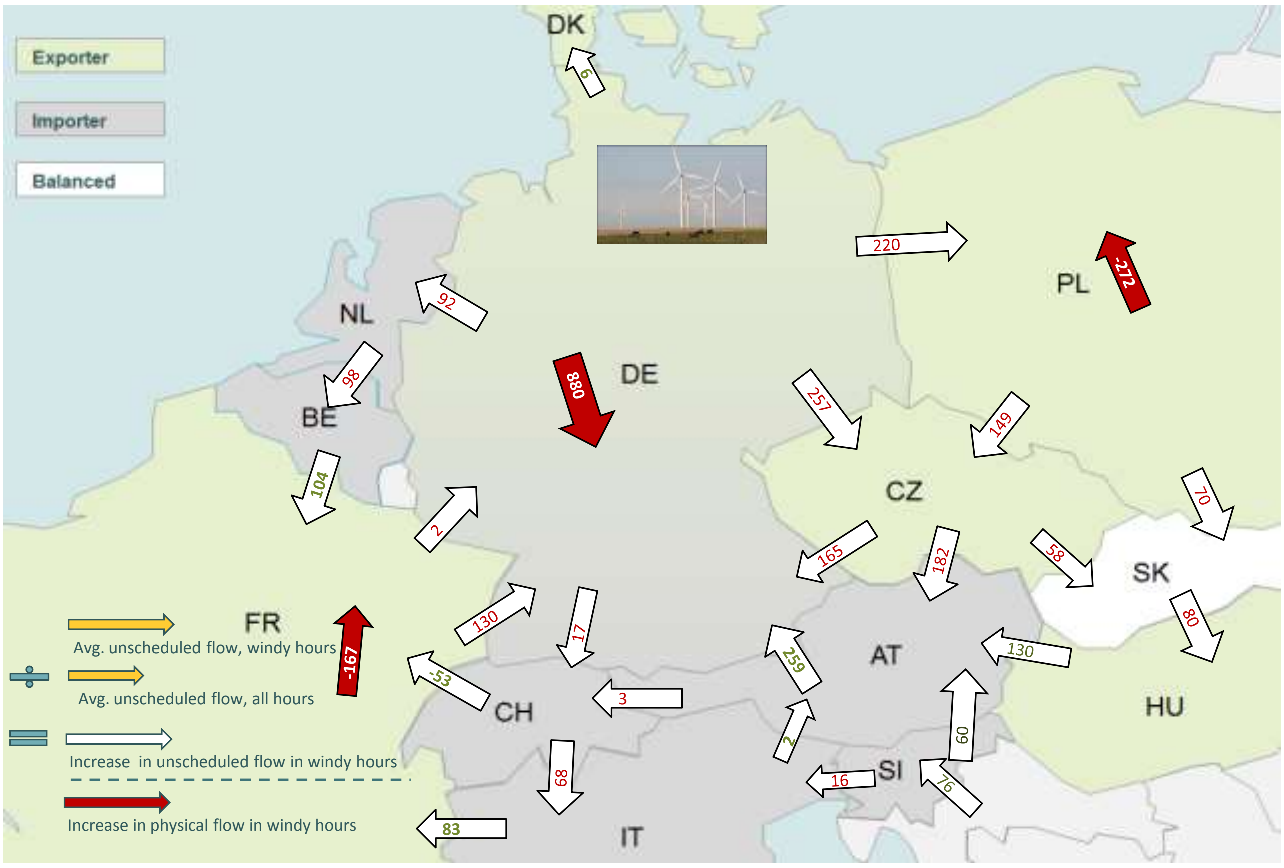
Furthermore, as Germany lies in the heart of Europe, it is natural that all loop and transit flows in the focus area of this study somehow relate to Germany.

The overall observations from the cases studied above allow identification of the following factors that contribute to the scale of unscheduled flows:

- *Insufficient price signals*: The market prices do not correctly reflect limitations in the physical grid, and do not account fully for bottlenecks within countries. While we focused the analysis on Germany, it is fair to assume that also bottlenecks in other countries are incorrectly accounted for as well.
- *Renewable feed-in:* The massive build-out of renewable generation creates large and fluctuating flows. But their generation feed-in is often not or incompletely related to price signals from the market. Often, renewable generation has priority access. This may create physical flows that deviate strongly from scheduled flows, in particular if the remaining generation is exposed to imperfect price signals that do not reflect bottlenecks.

The latter fact is also illustrated in Figure 19. The figure shows the same plot as Figure 8, except now it shows the difference in unscheduled flows (compared to the average) if there is high wind feed-in (as defined in footnote 9). We observe that the unscheduled flows increase throughout the Central Eastern loop in hours with high wind feed-in, while the effects on the Central Western transit and Southern Central loop are somewhat ambiguous.

Figure 19: Increased challenges with high wind feed-in. Changes in unscheduled flows.



Source: THEMA Consulting Group, based on data from 16 TSOs

4.2 Model analysis

In the previous section we analysed historical data and potential causes for loop and transit flows. Furthermore, in Chapter 3 we identified principle measures against loop flows. Depending on the nature of the loop flow, different measures can be applied.

In this chapter, we analyse the *market* consequences associated with different measures. For this we simulated the power markets in Europe before and after certain measures are applied, using our power market model The-MA. A detailed description of the model and the assumptions applied in the simulations are presented in Appendix B.

This section focusses on the market consequences of measures. As pointed out in the beginning of Chapter 4, we have not applied a physical grid model in this study. Thus, we cannot conclude with certainty that the measures proposed and analysed will actually resolve the challenges related to loop and transit flows. Also, different measures would in turn impact ATC values in Europe. For example, internal bidding zone delimitation in Germany would have an impact on the ATCs on all German borders and beyond. Such a grid assessment lies outside the scope of this study.

Please also note that our analysis focusses on the year 2013, and is subject to the assumptions on drivers such capacity mix, ATC values, demand developments, etc.

4.2.1 Modelled scenarios

All scenarios are modelled for the year 2013. A reference scenario for 2013 is modelled for comparison. In this reference scenario, Germany and Austria are considered one price zone.

As mentioned, we focus on measures whose market impact can be analysed by means of a dispatch model. Thus, the measures studied in this section are applied in the day-ahead market. Due to this restriction, the modelled measures do not completely match the list of measures in chapter 3. The main objective of this section, however, is not to find absolute answers, but to roughly quantify and test the impacts of different measures in a realistic market model.

We examine the consequences of the following measures:

- *Bidding zone delimitation:* Austria and Germany are modelled as three bidding zones: northern Germany, southern Germany, and Austria. A more detailed description how the delimitation was applied can be found in Appendix B. Roughly speaking, we applied data from the Regionenmodell for Germany to allocate generation, demand, and transmission constraints.[11] As there is large uncertainty around the actual internal transmission capacities within Germany, we applied a range of ATC values between north and south Germany.
- *ATC reduction:* Reducing the ATC capacities on the cross-border section between the northern part of Germany and the Netherlands by 20%. We reduced the ATC value flat for the entire year.
- *Wind curtailment:* Wind curtailment has been applied for wind in northern Germany. We first identified some hours in which bidding zone delimitation may yield a price spread in Germany, using the The-MA model. We then curtail the wind output in those identified hours in order to test the impact of possible measures implying the wind is curtailed in the market. The curtailment corresponds to a reduction of total output of some 3 TWh over the year.
- *Thermal curtailment:* In the same hours as wind was curtailed, we limit the available thermal capacity in northern Germany, in order to test the impact of possible measures implying that thermal generation is curtailed. We decrease capacity so that the net production decrease also in this case is roughly 3 TWh.

[11] The Regionenmodell (Regional Electricity Transport Model) is a transmission system model developed by the four German TSOs for the German transmission grid. The public results date from 2009 and 2013 and can be found, reps. http://www.50hertz.com/en/file/090901_Regionenmodell_Stromtransport_2009.pdf and http://www.50hertz.com/en/file/090901_Regionenmodell_Stromtransport_2013.pdf, last visited 30/08/2013.

- *DC-line:* The idea for this scenario is to move wind from northern Germany to southern Germany, by inserting a DC-line of 4 GW. The transmission line is coordinated with the wind feed-in in northern Germany. For this cable to have effect, we apply the bidding zone delimitation described in the bidding zone delimitation scenario for these model simulations.

In the scenario with bidding zone delimitation, we have only defined internal bidding zones for Germany. This should not be mistaken as a sign that Germany is the only country with local imbalances. The reason is simply that we did not have any quantitative basis to apply bidding zone delimitation in other countries like Poland or France. We did not find any publicly available data similar to the Regionenmodell for other countries that would have allowed us to make a similar assessment.

4.2.2 The impact of bidding zone delimitation in Germany

We have seen in the historical analysis that prices in Germany do not seem to reflect local balances sufficiently. In this particular case, prices in northern Germany seem to be too high in some instances, not only triggering “wrong” generation in Germany, but also triggering “wrong” cross-border flow and generation abroad, which potentially amplifies the challenges associated with unscheduled flows. Overall, it seems that in particular the Central East Europe loop is related to incorrect price signals.

The underlying problem is also illustrated in Figure 20, showing generation and trade consequences if local imbalances are not accounted for in the spot prices. As for northern Germany, prices may be too high. As a consequence, generation in northern Germany is higher than it should be, as thermal generation is incentivized by these higher prices. But in addition, imports on the Polish border are higher than they should be. This may potentially contribute to internal Polish grid challenges if the generation is located in such a way that it contributes to load on internal critical branches.

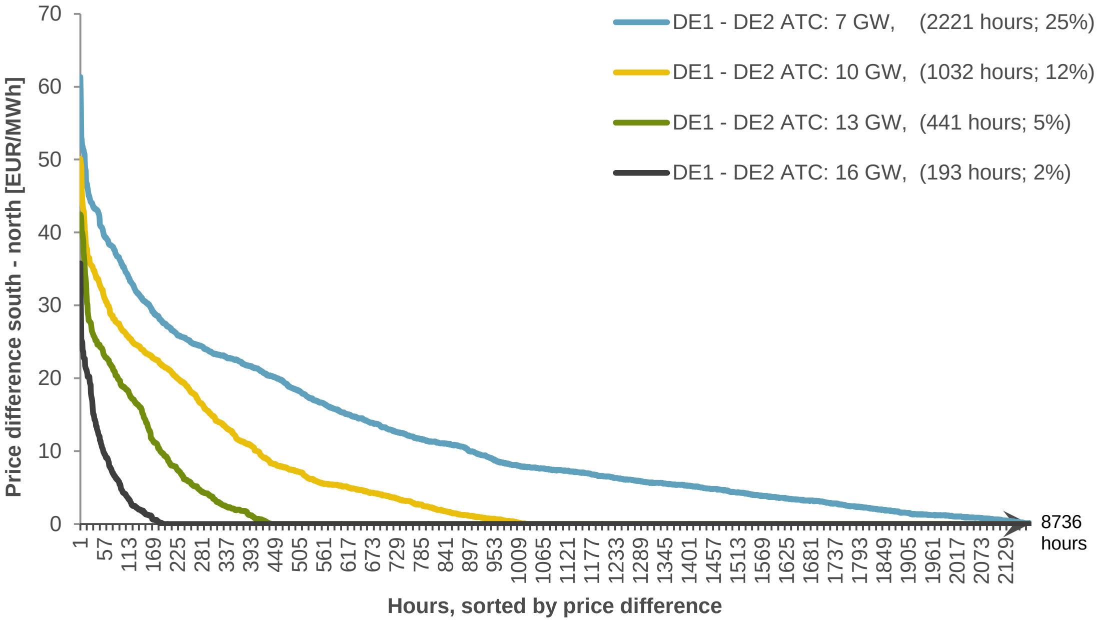
In southern Germany, the same problem occurs, only the other way around. Prices are lower than they should be, limiting generation incentives in south Germany, and triggering exports from Germany.

All things considered, the wrong price signals in Germany, combined with the effects on cross-border trade, amplify the internal congestion, and hence also the grid strain in neighbouring countries.

Figure 20: Illustration of challenges due to incomplete price signals

In this case, bidding zone delimitation may be a means to improve price signals. We therefore looked into how bidding zone delimitation may change prices in Germany, and how it may affect trade with the neighbouring countries in the critical hours.

Figure 21: Price difference duration curve in case of bidding zone delimitation between Southern and northern Germany sorted by magnitude [EUR per MWh]



Source: Simulation results from the power market model The-MA (The Market Analyser)

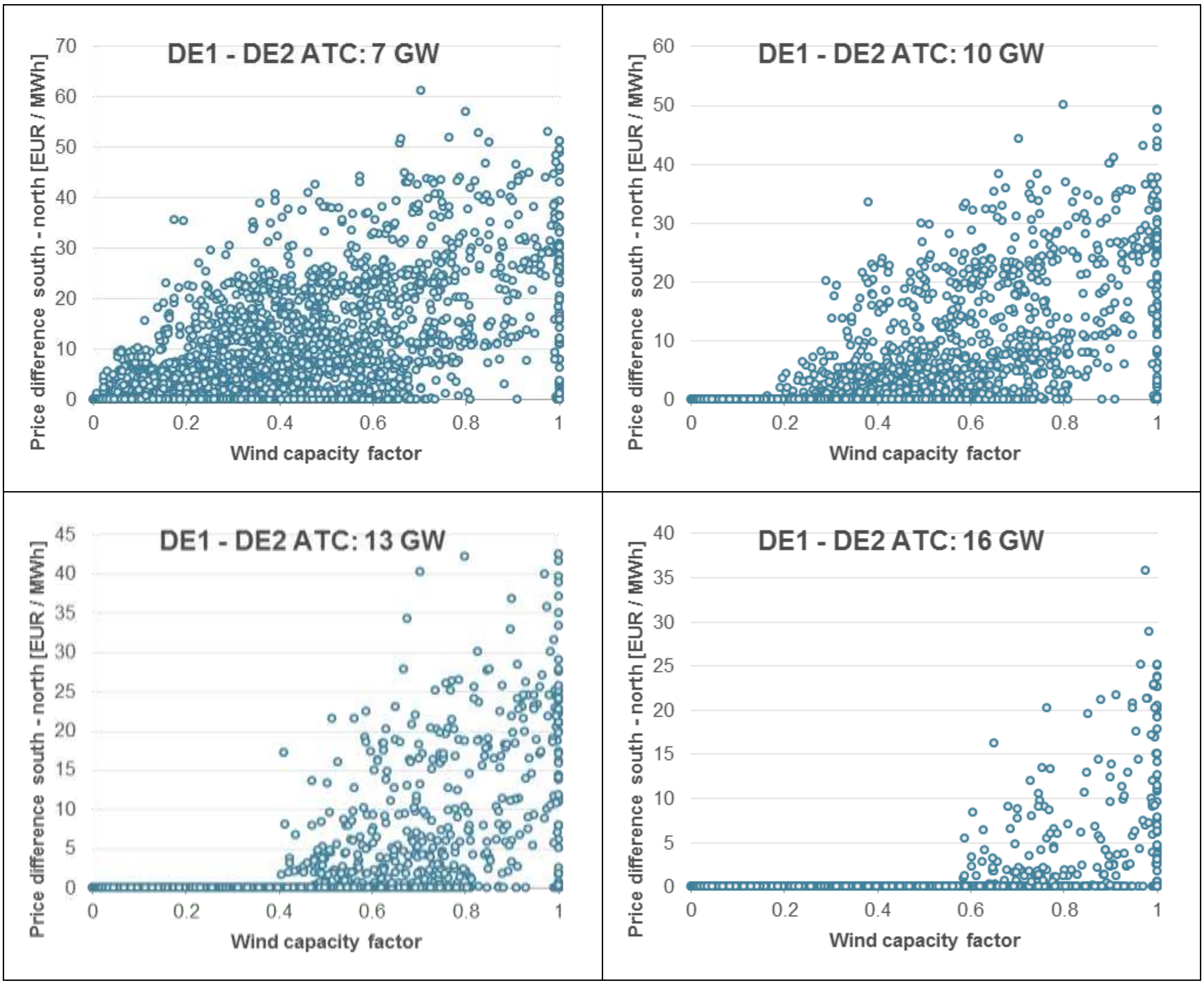
In order to apply bidding zone delimitation, we model Germany with an internal ATC value. But, as there is very large uncertainty as to what this internal ATC value may be, we modelled Germany with four different assumptions on internal transmission capacity: 7 GW, 10 GW, 13 GW, and 16 GW.

The impact of bidding zone delimitation depends on the assumed internal ATC in Germany. This is illustrated in Figure 21. The figure shows the *price difference* duration curve between southern and northern Germany, i.e. the price spread between the south and the north for the different ATC value, sorted by magnitude. Note that we "cut" the duration curve at around 2200 hours. This is the number of hours for which a price difference occurs in the case of 7 GW internal ATC.

An important aspect in the bidding zone delimitation measure is that the price differences occur in the hours where wind feed-in is high, i.e. in precisely the hours where local surplus in northern Germany is high. This is illustrated by the graphs in Figure 22. The graphs show the price differential between southern and northern Germany in relation to the (modelled) wind capacity factor in Germany. In all the different cases of internal ATC assumptions, we find a positive relationship between the price spread and the wind feed-in. In short, bidding zones matter in those hours where wind feed-in is high. In particular in cases with a high internal ATC, we observe that bidding zone delimitation yields a price differential *only* if the wind generation is high.

In other words, bidding zone delimitation has an impact in particular in hours with high wind feed-in, and hence in hours in which loop and transit flows are significant.

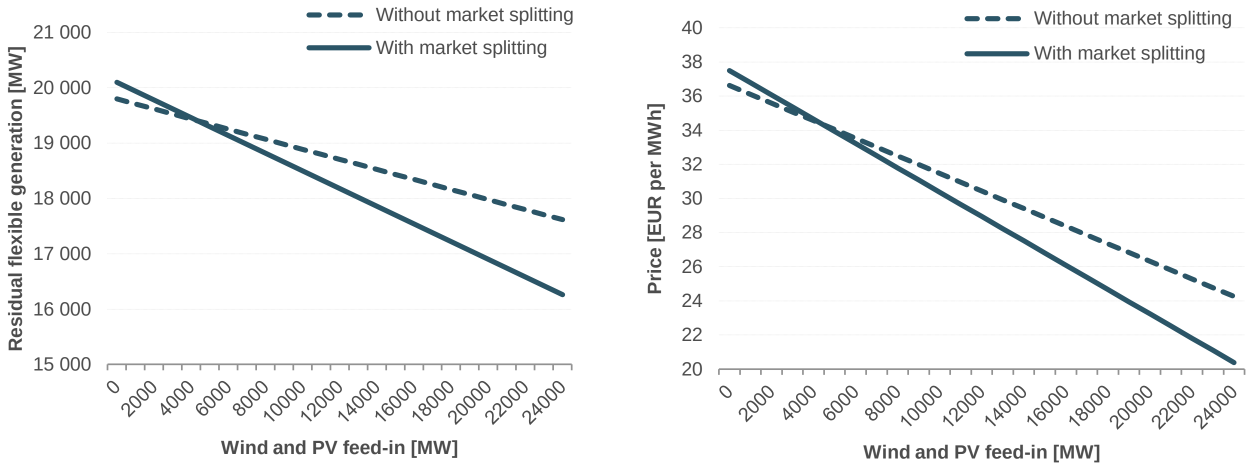
Figure 22: Price spread between southern and northern Germany as a function of wind output, given alternative ATC values between north and south



Source: Simulation results from the power market model The-MA (The Market Analyser)

In the case of bidding zone delimitation, we also find a much larger correlation between wind feed-in in Germany and prices in northern Germany. As a consequence, we also find a much stronger relation between wind feed-in and the residual thermal generation in northern Germany with internal bidding zones. This is reflected by the graphs in Figure 23. The graphs indicate the relationship between wind feed-in and residual generation as well as wind feed-in and prices in northern Germany with and without internal bidding zones. Thus, we can conclude that bidding zone delimitation matters in those hours where there are strong imbalances due to high wind generation.

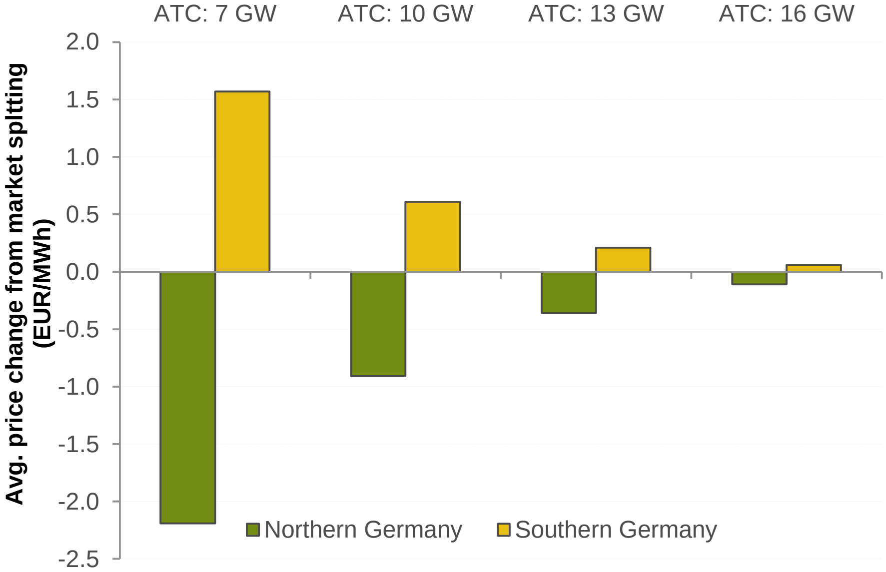
Figure 23: Wind vs. price in northern Germany and wind vs. residual generation in northern Germany in cases with and without internal German bidding zones (for internal ATC=13 GW)



Source: Simulation results from the power market model The-MA (The Market Analyser)

Figure 24 illustrates the impact of internal bidding zones on German prices in the north and in the south. The price effect of internal bidding zones depends strongly on the assumed internal ATC values. Nevertheless, if one does not assume a very low internal ATC, the effect on average prices is fairly modest.

Figure 24: Effect of bidding zone delimitation on power prices in southern and northern Germany



Source: Simulation results from the power market model The-MA (The Market Analyser)

The change in prices due to internal bidding zone delimitation also impacts cross-border trade (cf. Table 9). Furthermore, we find that scheduled flows between Germany and Poland are the more affected by internal bidding zones the higher the wind feed-in in Germany is.

Table 9: Change in annual trade (TWh) as a result of new bidding zones

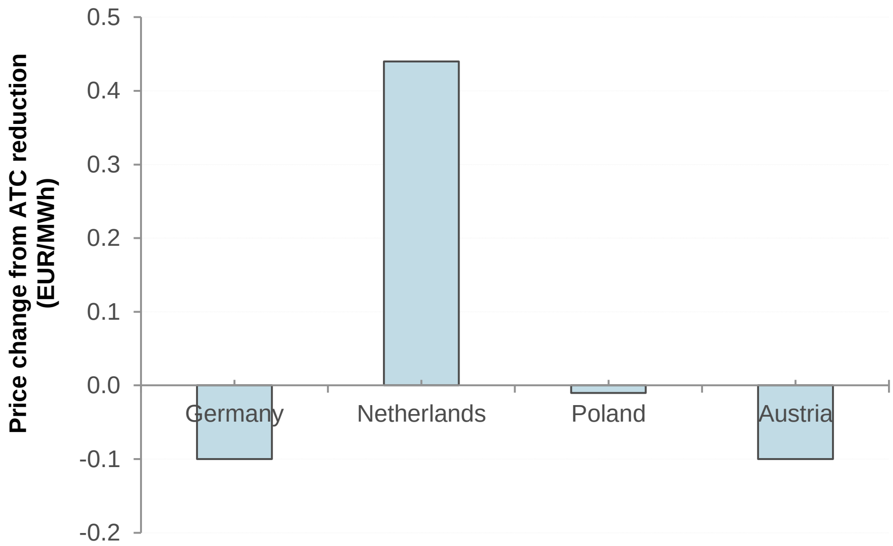
		Germany_North	Germany_South	Poland	Netherlands
From	**Germany_North**	0.0	-2.3	0.1	0.0
	Germany_South	-0.2	0.0	0.0	-0.1
	Poland	-0.1	0.0	0.0	0.0
	Netherlands	0.0	0.0	0.0	0.0
To	**Germany_North**	0.0	-0.2	-0.1	0.0
	Germany_South	-2.3	0.0	0.0	0.0
	Poland	0.1	0.0	0.0	0.0
	Netherlands	0.0	-0.1	0.0	0.0
From (net)	**Germany_North**	0.0	-2.1	0.2	0.0
	Germany_South	2.1	0.0	0.0	-0.1
	Poland	-0.2	0.0	0.0	0.0
	Netherlands	0.0	0.1	0.0	0.0

Source: Simulation results from the power market model The-MA (The Market Analyser)

4.2.3 ATC reduction between Germany and the Netherlands

The ATC reduction measure may be applied on the Central Western loop involving Germany, the Netherlands, Belgium, and France. In this case, physical flow exceeds scheduled flow on the German-Dutch border, and they are strongly correlated. Hence reducing scheduled flow may also reduce physical flow in case this causes challenges. We modelled this measure by reducing ATC between Germany and the Netherlands by 20%.

Figure 25: Price effect of the ATC measure (changes compared to reference case in EUR per MWh)



Source: Simulation results from the power market model The-MA (The Market Analyser)

Table 10: Change in annual trade (TWh) as a result of 20% ATC reduction on the German-Dutch border

		Germany_North	Germany_South	Poland	Netherlands
From	**Germany_North**	0.0	1.3	0.0	-2.3
	Germany_South	-0.4	0.0	0.0	0.1
	Poland	-0.1	0.0	0.0	0.0
	Netherlands	0.0	0.0	0.0	0.0
To	**Germany_North**	0.0	-0.4	-0.1	0.0
	Germany_South	1.3	0.0	0.0	0.0
	Poland	0.0	0.0	0.0	0.0
	Netherlands	-2.3	0.1	0.0	0.0
From (net)	**Germany_North**	0.0	1.7	0.1	-2.3
	Germany_South	-1.7	0.0	0.0	0.1
	Poland	-0.1	0.0	0.0	0.0
	Netherlands	2.3	-0.1	0.0	0.0

Source: Simulation results from the power market model The-MA (The Market Analyser)

We find that an ATC reduction in this case would increase Dutch prices, while prices in Germany and Austria would decrease. This is illustrated in Figure 25. This price effect yields new generation and trade patterns in general, in addition to the effect of the reduced ATC. The overall effect on trade is shown in Table 10.

We find that not only the trade from Germany to the Netherlands is reduced (as a result of a reduced ATC), but that there are also higher scheduled flows from Germany to Poland as a result of the price effect. Thus, this measure - addressing the Western loop in our model - may also contribute in relieving the Eastern loop.

Reducing the ATC value on interconnectors, however, significantly impacts the overall market efficiency. Thus, reducing ATC values increase the overall costs of delivered energy in the day-ahead market. This will be further discussed in the comparative section further below.

4.2.4 Curtailment

We have modelled both wind curtailment and thermal curtailment. This curtailment may be the result of a measure impacting generation output. In order to model curtailment, we have reduced the wind feed-in and thermal generation respectively in selected hours where internal bidding zones yield price differences (for an internal ATC value of 13 GW).

As explained above, in this section we focus on measures affecting the day-ahead market. This means that the curtailment is performed in the day-ahead market, with knowledge of market participants. This is of course a simplification, as in real life the curtailment may be applied in the re-dispatch or countertrade markets. Nevertheless, the simulations give some indication about the relative costs for these measures, and potential short-comings.

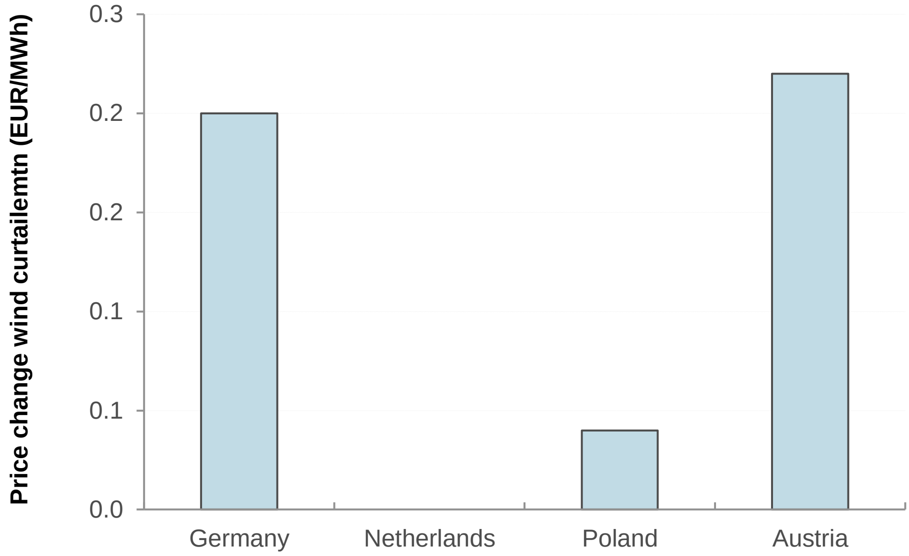
Wind curtailment

If wind power generation is the source of loop and transit flow problems, one might infer that the preferred measure would be to curtail wind. Wind curtailment reduces northern German wind generation, thus limiting scheduled flow from the north to the south of Germany (cf.Table 11). If this was a physical measure alone, the challenges associated with loop flows might be reduced, in particular on the eastern borders of Germany.

But the measure has a substantial flip side. Reducing wind feed-in in Germany increases prices in case the curtailment is visible and expected in the day-ahead market (cf. Figure 26). This has two effects: First, it increases generation incentives for German producers that are not curtailed – also in the north; second, it facilitates more imports from Poland (cf.Table 11). This increased generation in Poland may in turn contribute to internal bottleneck loading in Poland, although this depends on the location of the location of the generation that increases generation.

Thus, the effectiveness of this measure on the Eastern loop flow may be counteracted by potential spot market reactions.

Figure 26: Price effect of the wind curtailment measure (changes compared to reference case in EUR per MWh)



Source: Simulation results from the power market model The-MA (The Market Analyser)

Table 11: Change in annual trade (TWh) as a result of wind curtailment in northern Germany

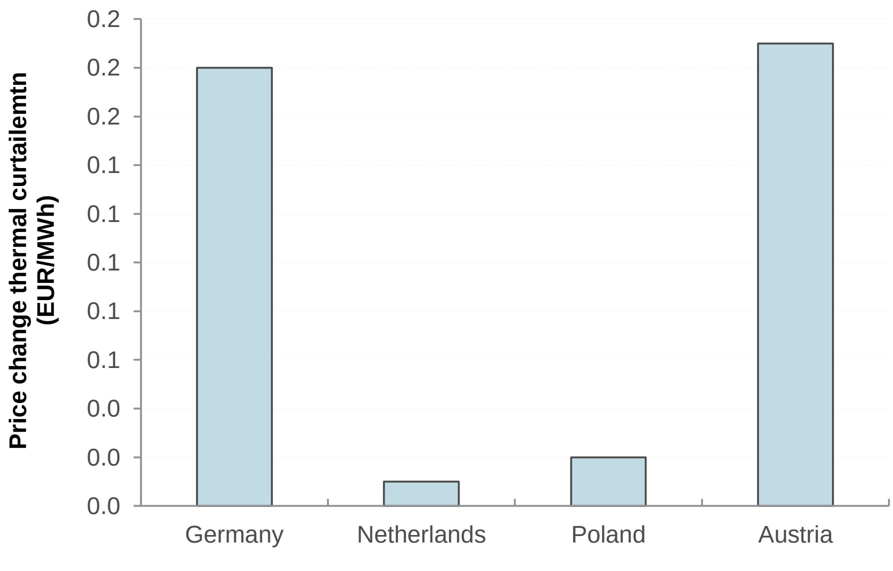
		Germany_North	Germany_South	Poland	Netherlands
From	**Germany_North**	0.0	-2.1	0.0	0.0
	Germany_South	0.0	0.0	0.0	0.0
	Poland	0.2	0.0	0.0	0.0
	Netherlands	0.0	0.0	0.0	0.0
To	**Germany_North**	0.0	0.0	0.2	0.0
	Germany_South	-2.1	0.0	0.0	0.0
	Poland	0.0	0.0	0.0	0.0
	Netherlands	0.0	0.0	0.0	0.0
From (net)	**Germany_North**	0.0	-2.1	-0.2	0.0
	Germany_South	2.1	0.0	0.0	0.0
	Poland	0.2	0.0	0.0	0.0
	Netherlands	0.0	0.0	0.0	0.0

Source: Simulation results from the power market model The-MA (The Market Analyser)

Thermal curtailment

The results for thermal curtailment are very similar as for wind curtailment in terms of qualitative effects. This is reflected in the numbers presented in Figure 27 and Table 12.[12] Thus, the effect of the measure does not depend on which generation is curtailed (if we abstract from precise grid topology issues and from the fact that thermal generation curtailment would also reduce the price sensitivity of the system).

Figure 27: Price effect of the thermal curtailment measure (changes compared to reference case in EUR per MWh)



Source: Simulation results from the power market model The-MA (The Market Analyser)

[12] Small differences in the results between thermal and wind curtailment are explained by the fact that the two measures, in terms of model implementation, are not 100% identical. Whereas it is straight-forward to curtail wind in the model, curtailing thermal generation is more challenging as thermal output is a function of the price, which in turn depends on the assumed curtailment.

Table 12: Change in annual trade (TWh) as a result of thermal curtailment in northern Germany

		Germany_North	Germany_South	Poland	Netherlands
From	**Germany_North**	0.0	-2.6	0.0	0.0
	Germany_South	0.0	0.0	0.0	0.0
	Poland	0.1	0.0	0.0	0.0
	Netherlands	0.0	0.0	0.0	0.0
To	**Germany_North**	0.0	0.0	0.1	0.0
	Germany_South	-2.6	0.0	0.0	0.0
	Poland	0.0	0.0	0.0	0.0
	Netherlands	0.0	0.0	0.0	0.0
From (net)	**Germany_North**	0.0	-2.6	-0.2	0.0
	Germany_South	2.6	0.0	0.0	0.0
	Poland	0.2	0.0	0.0	0.0
	Netherlands	0.0	0.0	0.0	0.0

Source: Simulation results from the power market model The-MA (The Market Analyser)

The socio-economic costs for thermal curtailment, however, are much lower than for wind curtailment. If the wind is blowing, wind turbines generate at zero marginal costs. Curtailing wind would therefore take out the "cheapest" generation. Curtailing thermal generation, on the other hand, would reduce generation with positive costs, probably generation that is price setting.

We find that thermal curtailment, *under the assumptions we modelled*, would be around EUR 80 million p.a. cheaper for Germany than curtailing wind.

4.2.5 New DC lines

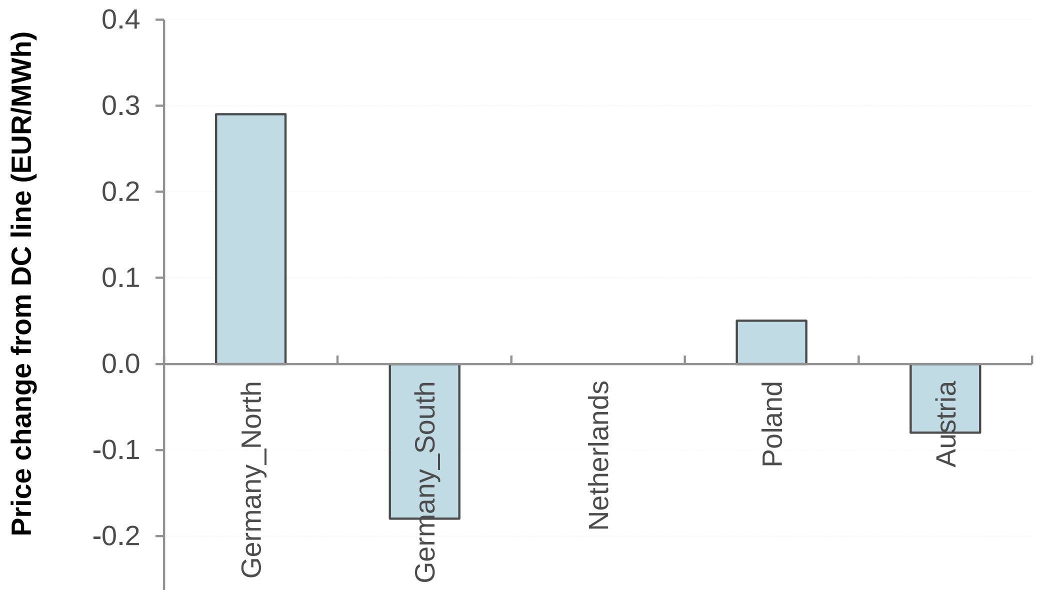
In this case we modelled a DC line of 4 GW between north and south Germany. This DC line transports wind power directly from the north to the south in Germany. In order to show any market effect in the model, we also applied internal bidding zone delimitation in the model in this case.[13] We modelled a flow on the DC line that relates to the wind feed-in in northern Germany, and with full load in the hours in which internal bidding zones result in a price difference. The internal ATC values are set at 13 GW. Effectively, this would "move" wind from the north to the south in Germany.

The benefits of such a measure would clearly be grid related, i.e. it would allow better control of the grid and flows. Therefore, a DC line is likely to reduce loop flows and also the strain on the grid in neighbouring countries. Note that DC lines are different from AC lines as they allow controlling the current and flow on the line. An AC line would change the topology of the grid, but flows would still be subject to Kirchhoff's laws. Therefore, DC lines allow much better control of the flows within a country and - as a consequence – potential loop flows.

A proper study of the physical effects, however, would require the use of a grid model. Therefore, the modelled market consequences of this measure are of somewhat limited value. What we can say is that the DC line (when modelled with internal bidding zones) would increase prices in northern Germany, as it would move wind generation from the north to the south of Germany (cf. Figure 28). This price increase may, similar to the curtailment measure, counteract some of the effects of this measure.

[13] The reason for assuming bidding zone delimitation is that without internal bidding zones, there would be no market consequence of the measure, only physical consequences. A study of these physical consequences lies outside the scope of the model applied. We acknowledge, however, that sufficient transmission investments may be an alternative to market splitting.

Figure 28: Price change from introducing a DC line from DE1 to DE2, relative to bidding zone delimitation scenario with 13 GW ATC (EUR per MWh)



Source: Simulation results from the power market model The-MA (The Market Analyser)

Table 13: Change in annual trade (TWh) as a result of DC lines transporting wind (changes compared to bidding zone delimitation scenario with ATC 13 GW in EUR per MWh)

		Germany_North	Germany_South	Poland	Netherlands
From	**Germany_North**	0.0	4.0	-0.1	0.0
	Germany_South	1.7	0.0	0.0	0.1
	Poland	0.1	0.0	0.0	0.0
	Netherlands	0.0	0.0	0.0	0.0
To	**Germany_North**	0.0	1.7	0.1	0.0
	Germany_South	4.0	0.0	0.0	0.0
	Poland	-0.1	0.0	0.0	0.0
	Netherlands	0.0	0.1	0.0	0.0
From (net)	**Germany_North**	0.0	2.3	-0.2	0.0
	Germany_South	-2.3	0.0	0.0	0.1
	Poland	0.2	0.0	0.0	0.0
	Netherlands	0.0	-0.1	0.0	0.0

Source: Simulation results from the power market model The-MA (The Market Analyser)

There are two principle challenges associated with this measure:

1. *How to operate a DC line without bidding zone delimitation:* It is not clear how a DC line will be operated in the absence of bidding zones in an effective manner. DC lines between for example the Nordics and the Continent are optimized in implicit auctions, effectively utilizing the cables in direction of the bidding zone with the higher price in each hour. In the absence of bidding zone delimitation, this price signal is missing, and it is not *a priori* clear how the cable should be utilized in a market efficient manner.

2. *How much DC capacity to build:* In our analysis we assumed a 4 GW DC line. While such a line is able to transport large volumes over the year, the peak load is of course limited to 4 GW. If capacity imbalances between the north and the south increase in the future, e.g. due to further imbalanced build-out of wind, the increase in DC line capacity would have to correspond to the capacity imbalance minus existing north-south capacity if one really wants to transport the very last MWh of excess wind from the north to the south. Thus, depending on how little imbalance one is willing to tolerate, one has to build out the internal grid substantially, which may be very costly.

4.2.6 Comparison and discussion of results

Table 14 summarizes and compares the market consequences of the measures analysed in this section.

It should be noted that one has to be careful in comparing the different measures directly. Firstly, we do not have a full overview over the implementation costs of the different measures; secondly, we do not know to what extent they will be comparable in terms of solving the physical challenges. Such an assessment would require a grid model.

Table 14: Summary of measures and implications

	Price effect					***Cost elements***			
	Northern Germany	**Southern Germany**	**Nether-lands**	**Poland**	**Austria**	**Cost for delivered energy in day-ahead market**	**Invest-ment costs**	**Other costs**	**Comment**
Price zone delimitation	↘	↗	↘	↘	↗	*Increase (but decrease in costs in other markets, e.g. Redispathing, counter-trade and balancing)*	*low*	*Transition costs and implementation costs*	*Limited risk, overall improved price signals, also abroad*
ATC reduc-tion	↘	↘	↗	↘	↘	*Increase (moderate)*	*low*	*Other benefits of market integration reduced*	*May re-allocate problems; probably not in line with IEM targets and legislation*
Thermal curtail-ment	↗	↗	–	–	↗	*Increase (but low)*	*low*	*Potentially high start-up costs and wear & tear costs*	*Effects may be limited counteracted by market reactions; potentially difficult to implement precisely*
Wind curtail-ment	↗	↗	–	↗	↗	*Increase (high)*	*low*	-	*Effects may be limited counteracted by market reactions; potentially difficult to implement*
DC line	↗	↘	–	↗	↘	*Decrease (but small)*	*high*	*Operating costs for DC line*	*Not clear how to operate without bidding zone delimitation; not clear what the optimal capacity would be*

We can draw some conclusions from the results:

- Internal bidding zone delimitation makes bottlenecks in the system visible to the market, improving overall price signals and market efficiency. Internal bidding zone delimitation increases the total cost of energy in the day-ahead market, because grid constraints are represented in the market solution. Without internal bidding zones, bottlenecks would have to be handled by redispatching or other means of balancing, potentially adding costs that are higher than the cost increase incurred in the day-ahead market. Thus, the increase in the total cost of energy in the spot market is not a new cost; the cost is only shifted from other markets into the day-ahead market. In this respect, it is reasonable to assume that handling bottlenecks in the day-ahead market is more cost efficient than handling them ex-post via redispatching or countertrade.

- In case of a DC line, we see an overall decrease in the total costs of energy delivered in the day-ahead market. A new DC line would reduce constraints in the day-ahead market, and hence reduce the total cost of electricity generation in the spot markets. At the same time, there are costs associated with transmission investments which we have not accounted for.

  But the overall decrease in energy costs is limited. Existing north-south interconnection in Germany is in most hours sufficient to eliminate price differences, i.e. it is not congested. The DC cable will therefore only have a direct market impact in a limited number of hours. Taking into account the cost of building new DC lines, this may be a rather costly measure if only targeting loop flows.

  The benefits of such a solution are therefore likely to be mostly related to handling the physical grid, not only in Germany, but also in neighbouring countries. A grid impact study, however, lies outside the scope of this study. The question remains, though, how a DC line should be operated without internal bidding zone delimitation, and what the most efficient capacity on such a link would be.

- A reduction in the ATC value from Germany to the Netherlands will decrease the overall market efficiency. As trade opportunities are reduced, the overall costs for delivered energy in the day-ahead market increases. In addition, there is a chance that a reduction in the ATC value on one interconnector may increase loop flows or grid challenges elsewhere.

  Furthermore, using cross-border allocation to handle internal bottlenecks may not be in line with the current legislation and the IEM targets.

- If generation should be curtailed, it would be best to curtail thermal generation and not wind generation when considering the impact on the cost for delivered energy in the spot market.[14] If the wind blows it produces at short-run marginal costs close to zero, while thermal generation has short-run marginal costs related to fuel costs and CO_2 costs. If generation is to be curtailed it therefore seems reasonable to curtail the most expensive generation first, instead of curtailing the cheaper generation sources. This similar to what a price reduction as a result of bidding zone delimitation would effectively do: It would reduce output from the more expensive units.

As mentioned, a direct comparison between the measures is difficult, as we cannot know in detail how they would impact that actual physical challenges associated with loop flows. But it can be argued that bidding zone delimitation is an effective means to give more efficient price signal in hours where bottlenecks are imminent. The other measures try to essentially address the same problem, but may be more costly, and not in line with the IEM targets. At the same time, some of the measures may have limited effects as they are counteracted by market reactions.

We also see from our model analysis that all of the discussed measures have effects both in the countries applied and in their neighbouring countries. Thus, they may have additional side effects (e.g. on physical flow) that are not captured by our analysis. From that perspective one should not employ “patch” measures with local focus, but measures that have an overall system perspective. Improving price signals by making bottlenecks visible to the market is a measure that would improve resource allocation from an overall system point of view.

[14] The exception is when start-stop costs make it more costly to curtail thermal generation than wind.

4.3 Concluding remarks

We have conducted a detailed analysis of historical data. In this analysis we found strong indications that local imbalances and renewable feed-in generation are at the heart of the problems currently associated with loop flows. While we exemplified these issues using foremost German data, although it is reasonable to assume that local imbalances in other countries add and/or cause similar problems. The nature of the problems, however, may differ from case to case and from area to area.

We find that bidding zone delimitation is likely to improve the situation. Other, more direct measures, such as wind curtailment, may be counteracted by market reactions, hence muting their effectiveness. Thus, instead of interfering with the market, one should consider a market based solution that improves initial generation and trade decisions instead of trying to reduce the problem ex-post.

It has to be noticed that we did not apply a physical model or a grid model in our assessment. Therefore, we cannot conclude with certainty the extent to which different measures may actually resolve the challenges associated with the physical flows. The focus of the analysis has been on the market impacts of various measures.

Nevertheless, given the observed correlations from the historical data and the results from the model simulations, there are strong indications that internal bidding zone delimitation will contribute to a more cost-efficient solution. If other measures are needed, as for example phase-shifters, a proper grid assessment for the entire system should be conducted to analyse whether such measures are effective, or whether they simply re-allocate the problems.

Regarding bidding zone delimitation, we would like to emphasise again the fact that price zone delimitation within a control area may also be an efficient measure even if the bottlenecks occur in *other* control areas, and *not* the control area itself. In other words, the answer to whether a European country should be split into bidding zones is not necessarily a question of whether there are bottlenecks within this country, but whether bidding zone delimitation would contribute to relieving the system bottlenecks in a cost efficient manner in a larger region.

APPENDIX A: CORRELATION OVERVIEW

Table A.1: Correlation coefficients related to countries DE, NL, BE, FR, CH, AT

	*DK1-TenneT	*sum								*APG	*DK1-TenneT	*sum								*APG	*DK1-TenneT	*sum								*APG				*DK1	*TenneT	*TenneT			*TenneT						*ZANDV380
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]
DK-DE physical [1]	1.00	0.07	0.25	0.16	0.18	-0.07	0.00	0.20	0.20	0.02	**1.00**	0.01	0.19	0.05	0.18	-0.05	0.02	0.19	0.11	0.12	-0.09	0.14	0.16	0.16	-0.14	-0.02	-0.03	0.06	0.18	-0.18	0.23	0.17	0.12	0.01	-0.18	-0.02	-0.13	0.04	0.13	0.09	0.03	0.19	-0.04	0.15	-0.07
DE-NL physical [2]	0.07	1.00	0.32	-0.14	0.51	-0.33	-0.01	-0.03	0.35	0.18	0.07	**0.90**	-0.03	-0.49	0.53	-0.39	0.16	-0.12	0.25	0.06	-0.04	0.60	0.63	0.63	-0.40	0.16	-0.28	0.16	0.28	0.08	-0.41	-0.29	-0.14	0.19	0.18	0.14	0.15	0.16	-0.14	-0.41	-0.58	-0.05	-0.20	-0.10	-0.19
NL-BE physical [3]	0.25	0.32	1.00	0.53	0.69	-0.15	0.58	0.42	0.64	0.31	0.25	0.15	**0.83**	0.17	**0.77**	-0.13	0.61	0.25	0.61	0.27	-0.01	0.46	0.52	0.52	-0.65	0.01	0.10	0.43	0.39	-0.11	0.12	0.21	0.23	0.24	0.23	-0.05	0.12	0.04	0.53	0.40	0.02	0.37	0.10	0.50	-0.68
BE-FR physical [4]	0.16	-0.14	0.53	1.00	0.53	-0.21	0.40	0.26	0.31	0.27	0.16	-0.21	0.57	**0.82**	0.51	-0.12	0.33	0.12	0.27	0.31	-0.02	0.08	0.09	0.09	-0.33	-0.09	0.22	0.32	0.20	-0.21	0.15	0.16	0.16	0.16	0.21	0.04	-0.01	0.07	0.27	0.38	0.47	0.17	0.40	0.53	-0.39
DE-FR physical [5]	0.18	0.51	0.69	0.53	1.00	-0.58	0.31	0.11	0.55	0.28	0.18	0.46	0.54	0.23	**0.91**	-0.44	0.37	-0.08	0.37	0.17	-0.04	0.32	0.40	0.41	-0.51	-0.06	-0.02	0.39	0.45	0.00	-0.08	0.04	0.11	0.19	0.15	0.20	-0.03	0.21	0.23	0.08	-0.09	0.17	0.24	0.21	-0.43
FR-CH physical [6]	-0.07	-0.33	-0.15	-0.21	-0.58	1.00	0.32	0.30	0.01	0.22	-0.08	-0.35	-0.04	-0.07	-0.47	**0.73**	0.30	0.35	0.22	0.14	0.05	-0.12	-0.20	-0.20	0.17	0.15	0.10	-0.02	-0.15	0.01	-0.06	-0.15	-0.08	0.07	0.11	-0.35	0.17	-0.31	-0.03	0.01	0.09	-0.24	-0.10	0.30	0.08
DE-CH physical [7]	0.00	-0.01	0.58	0.40	0.31	0.32	1.00	0.58	0.65	0.52	-0.01	-0.02	0.68	0.35	0.47	0.42	**0.85**	0.40	0.67	0.29	0.10	0.00	0.00	0.00	-0.54	-0.23	0.50	0.49	0.35	0.05	0.08	0.08	0.14	0.24	0.24	-0.12	0.13	-0.14	0.48	0.36	0.28	0.06	0.37	0.55	-0.41
CH-IT physical [8]	0.20	-0.03	0.42	0.26	0.11	0.30	0.58	1.00	0.56	0.26	0.19	-0.06	0.45	0.19	0.26	0.28	0.50	**0.89**	0.43	0.22	0.02	0.05	0.06	0.06	-0.40	-0.04	0.27	0.46	0.42	-0.09	0.18	0.17	0.14	0.13	0.10	-0.04	0.03	-0.07	0.40	0.34	0.19	0.24	0.06	0.41	-0.21
AT-CH physical [9]	0.20	0.35	0.64	0.31	0.55	0.01	0.65	0.56	1.00	0.51	0.19	0.30	0.57	0.11	0.67	0.06	0.69	0.34	0.67	0.17	0.02	0.25	0.28	0.28	-0.63	-0.07	0.10	0.58	**0.81**	0.23	-0.08	-0.03	0.07	0.17	0.11	0.03	0.04	0.03	0.31	0.12	-0.04	0.16	0.17	0.33	-0.30
DE-AT physical [10]	0.02	0.18	0.31	0.27	0.28	0.22	0.52	0.26	0.51	1.00	0.01	0.14	0.28	0.16	0.34	0.18	0.48	0.06	0.46	**0.79**	0.05	0.15	0.13	0.14	-0.33	0.01	0.19	0.45	0.32	-0.25	-0.40	-0.35	-0.15	0.25	0.34	0.08	0.24	0.08	-0.11	-0.12	-0.17	-0.42	0.29	0.40	-0.16
DK-DE schedule [11]	**1.00**	0.07	0.25	0.16	0.18	-0.08	-0.01	0.19	0.19	0.01	1.00	0.02	0.18	0.04	0.18	-0.06	0.01	0.19	0.11	0.12	-0.19	0.14	0.17	0.16	-0.14	-0.01	-0.04	0.06	0.17	-0.18	0.23	0.17	0.12	0.00	-0.18	-0.03	-0.13	0.04	0.13	0.09	0.02	0.18	-0.05	0.15	-0.07
DE-NL schedule [12]	0.01	**0.90**	0.15	-0.21	0.46	-0.35	-0.02	-0.06	0.30	0.14	0.02	1.00	-0.02	-0.37	0.45	-0.27	0.05	-0.15	0.12	-0.03	-0.03	0.20	0.31	0.31	-0.31	-0.02	-0.12	0.16	0.31	0.18	-0.41	-0.32	-0.16	0.16	0.13	0.16	0.09	0.12	-0.18	-0.46	-0.52	-0.11	-0.12	-0.17	-0.06
NL-BE schedule [13]	0.19	-0.03	**0.83**	0.57	0.54	-0.04	0.68	0.45	0.57	0.28	0.18	-0.02	1.00	0.52	0.59	0.15	0.53	0.29	0.47	0.17	0.03	-0.03	-0.05	-0.04	-0.48	-0.27	0.42	0.43	0.39	0.00	0.25	0.25	0.26	0.18	0.14	-0.13	0.03	-0.09	0.57	0.49	0.27	0.32	0.30	0.52	-0.57
BE-FR schedule [14]	0.05	-0.49	0.17	**0.82**	0.23	-0.07	0.35	0.19	0.11	0.16	0.04	-0.37	0.52	1.00	0.17	0.16	0.12	0.10	0.02	0.15	0.02	-0.42	-0.49	-0.50	-0.04	-0.33	0.46	0.21	0.13	-0.07	0.23	0.15	0.13	0.04	0.07	-0.02	-0.12	-0.06	0.20	0.36	0.63	0.06	0.51	0.40	-0.14
DE-FR schedule [15]	0.18	0.53	**0.77**	0.51	**0.91**	-0.47	0.47	0.26	0.67	0.34	0.18	0.45	0.59	0.17	1.00	-0.25	0.41	0.03	0.41	0.17	-0.02	0.37	0.47	0.47	**-0.82**	-0.21	0.21	0.51	0.58	0.07	-0.07	0.04	0.11	0.21	0.19	0.15	0.04	0.14	0.29	0.12	-0.08	0.18	0.25	0.28	-0.50
FR-CH schedule [16]	-0.05	-0.39	-0.13	-0.12	-0.44	**0.73**	0.42	0.28	0.06	0.18	-0.06	-0.27	0.15	0.16	-0.25	1.00	0.15	0.35	0.05	0.01	0.11	-0.38	-0.47	-0.46	-0.09	-0.56	0.56	-0.07	0.04	0.16	0.04	-0.06	-0.03	0.03	0.04	-0.31	0.09	-0.33	0.06	0.11	0.23	-0.20	0.12	0.26	0.08
DE-CH schedule [17]	0.02	0.16	0.61	0.33	0.37	0.30	**0.85**	0.50	0.69	0.48	0.01	0.05	0.53	0.12	0.41	0.15	1.00	0.39	**0.78**	0.28	0.07	0.27	0.28	0.29	-0.35	0.15	-0.03	0.34	0.32	0.04	0.01	0.06	0.12	0.25	0.24	-0.08	0.13	-0.06	0.43	0.28	0.13	0.09	0.16	0.49	-0.41
CH-IT schedule [18]	0.19	-0.12	0.25	0.12	-0.08	0.35	0.40	**0.89**	0.34	0.06	0.19	-0.15	0.29	0.10	0.03	0.35	0.39	1.00	0.33	0.10	0.04	0.01	0.01	0.01	-0.18	-0.09	0.11	0.01	0.19	-0.10	0.26	0.24	0.14	0.06	0.04	-0.09	0.01	-0.11	0.36	0.36	0.21	0.26	-0.10	0.32	-0.11
AT-CH schedule [19]	0.11	0.25	0.61	0.27	0.37	0.22	0.67	0.43	0.67	0.46	0.11	0.12	0.47	0.02	0.41	0.05	**0.78**	0.33	1.00	0.34	0.03	0.35	0.37	0.37	-0.33	0.19	-0.02	0.29	0.12	-0.09	-0.04	0.03	0.09	0.23	0.24	-0.06	0.18	0.00	0.34	0.22	0.03	0.15	0.05	0.43	-0.38
DE-AT schedule [20]	0.12	0.06	0.27	0.31	0.17	0.14	0.29	0.22	0.17	**0.79**	0.12	-0.03	0.17	0.15	0.17	0.01	0.28	0.10	0.34	1.00	0.01	0.20	0.21	0.21	-0.13	0.15	0.10	0.29	-0.04	**-0.79**	-0.21	-0.13	-0.03	0.30	0.44	0.13	0.30	0.18	-0.03	0.07	-0.07	-0.28	0.15	0.48	-0.10
DK-DE unsched. [21]	-0.09	-0.04	-0.01	-0.02	-0.04	0.05	0.10	0.02	0.02	0.05	-0.19	-0.03	0.03	0.02	-0.02	0.11	0.07	0.04	0.03	0.01	1.00	-0.03	-0.07	-0.07	-0.02	-0.09	0.08	-0.02	0.01	0.03	-0.01	0.01	0.00	0.07	0.07	0.03	0.03	0.00	0.00	0.05	0.04	-0.01	0.05	0.05	-0.01
DE-NL unsched. [22]	0.14	0.60	0.46	0.08	0.32	-0.12	0.00	0.05	0.25	0.15	0.14	0.20	-0.03	-0.42	0.37	-0.38	0.27	0.01	0.35	0.20	-0.03	1.00	**0.87**	**0.86**	-0.33	0.40	-0.43	0.08	0.06	-0.16	-0.18	-0.06	-0.02	0.14	0.17	0.03	0.17	0.15	0.03	-0.07	-0.36	0.11	-0.23	0.10	-0.31
NL-BE unsched. [23]	0.16	0.63	0.52	0.09	0.40	-0.20	0.00	0.06	0.28	0.13	0.17	0.31	-0.05	-0.49	0.47	-0.47	0.28	0.01	0.37	0.21	-0.07	**0.87**	1.00	**0.99**	-0.43	0.44	-0.47	0.11	0.09	-0.19	-0.16	-0.01	0.01	0.16	0.20	0.10	0.18	0.21	0.07	-0.05	-0.38	0.17	-0.29	0.11	-0.35
BE-FR unsched. [24]	0.16	0.63	0.52	0.09	0.41	-0.20	0.00	0.06	0.28	0.14	0.16	0.31	-0.04	-0.50	0.47	-0.46	0.29	0.01	0.37	0.21	-0.07	**0.86**	**0.99**	1.00	-0.43	0.44	-0.47	0.11	0.09	-0.19	-0.17	-0.02	0.01	0.17	0.20	0.11	0.19	0.21	0.06	-0.05	-0.39	0.16	-0.28	0.11	-0.35
DE-FR unsched. [25]	-0.14	-0.40	-0.65	-0.33	-0.51	0.17	-0.54	-0.40	-0.63	-0.33	-0.14	-0.31	-0.48	-0.04	**-0.82**	-0.09	-0.35	-0.18	-0.33	-0.13	-0.02	-0.33	-0.43	-0.43	1.00	0.35	-0.46	-0.52	-0.58	-0.13	0.04	-0.04	-0.08	-0.18	-0.18	-0.05	-0.12	-0.01	-0.29	-0.14	0.06	-0.14	-0.20	-0.30	0.45
FR-CH unsched. [26]	-0.02	0.16	0.01	-0.09	-0.06	0.15	-0.23	-0.04	-0.07	0.01	-0.01	-0.02	-0.27	-0.33	-0.21	-0.56	0.15	-0.09	0.19	0.15	-0.09	0.40	0.44	0.44	0.35	1.00	-0.68	0.08	-0.25	-0.22	-0.13	-0.10	-0.06	0.04	0.07	0.04	0.07	0.12	-0.13	-0.14	-0.22	0.00	-0.30	-0.01	-0.02
DE-CH unsched. [27]	-0.03	-0.28	0.10	0.22	-0.02	0.10	0.50	0.27	0.10	0.19	-0.04	-0.12	0.42	0.46	0.21	0.56	-0.03	0.11	-0.02	0.10	0.08	-0.43	-0.47	-0.47	-0.46	-0.68	1.00	0.38	0.15	0.02	0.12	0.06	0.07	0.06	0.05	-0.09	0.03	-0.17	0.22	0.22	0.32	-0.05	0.44	0.24	-0.10
CH-IT unsched. [28]	0.06	0.16	0.43	0.32	0.39	-0.02	0.49	0.46	0.58	0.45	0.06	0.16	0.43	0.21	0.51	-0.07	0.34	0.01	0.29	0.29	-0.02	0.08	0.11	0.11	-0.52	0.08	0.38	1.00	0.55	-0.01	-0.11	-0.09	0.02	0.17	0.13	0.09	0.04	0.06	0.17	0.05	0.00	0.01	0.32	0.27	-0.25
AT-CH unsched. [29]	0.18	0.28	0.39	0.20	0.45	-0.15	0.35	0.42	**0.81**	0.32	0.17	0.31	0.39	0.13	0.58	0.04	0.32	0.19	0.12	-0.04	0.01	0.06	0.09	0.09	-0.58	-0.25	0.15	0.55	1.00	0.38	-0.07	-0.07	0.02	0.04	-0.05	0.09	-0.09	0.04	0.15	-0.02	-0.08	0.10	0.19	0.10	-0.11
DE-AT unsched. [30]	-0.18	0.08	-0.11	-0.21	0.00	0.01	0.05	-0.09	0.23	-0.25	-0.18	0.18	0.00	-0.07	0.07	0.16	0.04	-0.10	-0.09	**-0.79**	0.03	-0.16	-0.19	-0.19	-0.13	-0.22	0.02	-0.01	0.38	1.00	-0.07	-0.15	-0.09	-0.22	-0.36	-0.12	-0.23	-0.21	-0.06	-0.23	-0.05	0.02	0.05	-0.36	0.00
DE price [31]	0.23	-0.41	0.12	0.15	-0.08	-0.06	0.08	0.18	-0.08	-0.40	0.23	-0.41	0.25	0.23	-0.07	0.04	0.01	0.26	-0.04	-0.21	-0.01	-0.18	-0.16	-0.17	0.04	-0.13	0.12	-0.11	-0.07	-0.07	1.00	**0.82**	0.47	-0.16	-0.30	0.09	-0.23	0.06	0.63	0.68	0.58	0.58	-0.10	0.03	0.00
NL price [32]	0.17	-0.29	0.21	0.16	0.04	-0.15	0.08	0.17	-0.03	-0.35	0.17	-0.32	0.25	0.15	0.04	-0.06	0.06	0.24	0.03	-0.13	0.01	-0.06	-0.01	-0.02	-0.04	-0.10	0.06	-0.09	-0.07	-0.15	**0.82**	1.00	0.53	-0.07	-0.17	0.19	-0.13	0.16	0.65	**0.74**	0.52	0.64	-0.17	0.05	-0.07
BE price [33]	0.12	-0.14	0.23	0.16	0.11	-0.08	0.14	0.14	0.07	-0.15	0.12	-0.16	0.26	0.13	0.11	-0.03	0.12	0.14	0.09	-0.03	0.00	-0.02	0.01	0.01	-0.08	-0.06	0.07	0.02	0.02	-0.09	0.47	0.53	1.00	-0.01	-0.07	0.07	-0.07	0.05	0.43	0.45	0.32	0.39	-0.06	0.12	-0.11
DK wind [34]	0.01	0.19	0.24	0.16	0.19	0.07	0.24	0.13	0.17	0.25	0.00	0.16	0.18	0.04	0.21	0.03	0.25	0.06	0.23	0.30	0.07	0.14	0.16	0.17	-0.18	0.04	0.06	0.17	0.04	-0.22	-0.16	-0.07	-0.01	1.00	0.67	-0.02	0.17	0.01	0.00	0.07	-0.01	-0.02	0.06	0.45	-0.20
DE wind [35]	-0.18	0.18	0.23	0.21	0.15	0.11	0.24	0.10	0.11	0.34	-0.18	0.13	0.14	0.07	0.19	0.04	0.24	0.04	0.24	0.44	0.07	0.17	0.20	0.20	-0.18	0.07	0.05	0.13	-0.05	-0.36	-0.30	-0.17	-0.07	0.67	1.00	-0.09	0.40	-0.03	-0.12	0.05	-0.02	-0.14	0.10	0.59	-0.23
DE pv [36]	-0.02	0.14	-0.05	0.04	0.20	-0.35	-0.12	-0.04	0.03	0.08	-0.03	0.16	-0.13	-0.02	0.15	-0.31	-0.08	-0.09	-0.06	0.13	0.03	0.03	0.10	0.11	-0.05	0.04	-0.09	0.09	0.09	-0.12	0.09	0.19	0.07	-0.02	-0.09	1.00	-0.15	**0.72**	-0.02	0.19	-0.11	0.14	-0.08	-0.30	0.07
FR wind [37]	-0.13	0.15	0.12	-0.01	-0.03	0.17	0.13	0.03	0.04	0.24	-0.13	0.09	0.03	-0.12	0.04	0.09	0.13	0.01	0.18	0.30	0.03	0.17	0.18	0.19	-0.12	0.07	0.03	0.04	-0.09	-0.23	-0.23	-0.13	-0.07	0.17	0.40	-0.15	1.00	-0.08	-0.06	-0.01	-0.11	-0.08	-0.04	0.24	-0.11
FR pv [38]	0.04	0.16	0.04	0.07	0.21	-0.31	-0.14	-0.07	0.03	0.08	0.04	0.12	-0.09	-0.06	0.14	-0.33	-0.06	-0.11	0.00	0.18	0.00	0.15	0.21	0.21	-0.01	0.12	-0.17	0.06	0.04	-0.21	0.06	0.16	0.05	0.01	-0.03	**0.72**	-0.08	1.00	0.00	0.16	-0.20	0.16	-0.08	-0.19	0.09
DE other gen. [39]	0.13	-0.14	0.53	0.27	0.23	-0.03	0.48	0.40	0.31	-0.11	0.13	-0.18	0.57	0.20	0.29	0.06	0.43	0.36	0.34	-0.03	0.00	0.03	0.07	0.06	-0.29	-0.13	0.22	0.17	0.15	-0.06	0.63	0.65	0.43	0.00	-0.12	-0.02	-0.06	0.00	1.00	**0.76**	0.53	0.69	-0.06	0.21	-0.25
NL other gen. [40]	0.09	-0.41	0.40	0.38	0.08	0.01	0.36	0.34	0.12	-0.12	0.09	-0.46	0.49	0.36	0.12	0.11	0.28	0.36	0.22	0.07	0.05	-0.07	-0.05	-0.05	-0.14	-0.14	0.22	0.05	-0.02	-0.23	0.68	**0.74**	0.45	0.07	0.05	0.19	-0.01	0.16	**0.76**	1.00	0.65	0.65	-0.05	0.31	-0.20
BE other gen. [41]	0.03	-0.58	0.02	0.47	-0.09	0.09	0.28	0.19	-0.04	-0.17	0.02	-0.52	0.27	0.63	-0.08	0.23	0.13	0.21	0.03	-0.07	0.04	-0.36	-0.38	-0.39	0.06	-0.22	0.32	0.00	-0.08	-0.05	0.58	0.52	0.32	-0.01	-0.02	-0.11	-0.11	-0.20	0.53	0.65	1.00	0.40	0.13	0.28	-0.01
AT other gen. [42]	0.19	-0.05	0.37	0.17	0.17	-0.24	0.06	0.24	0.16	-0.42	0.18	-0.11	0.32	0.06	0.18	-0.20	0.09	0.26	0.15	-0.28	-0.01	0.11	0.17	0.16	-0.14	0.00	-0.05	0.01	0.10	0.02	0.58	0.64	0.39	-0.02	-0.14	0.14	-0.08	0.16	0.69	0.65	0.40	1.00	-0.26	0.01	-0.12
FR north-south [43]	-0.04	-0.20	0.10	0.40	0.24	-0.10	0.37	0.06	0.17	0.29	-0.05	-0.12	0.30	0.51	0.25	0.12	0.16	-0.10	0.05	0.15	0.05	-0.23	-0.29	-0.28	-0.20	-0.30	0.44	0.32	0.19	0.05	-0.10	-0.17	-0.06	0.06	0.10	-0.08	-0.04	-0.08	-0.06	-0.05	0.13	-0.26	1.00	0.22	-0.08
DE north-south [44]	0.15	-0.10	0.50	0.53	0.21	0.30	0.55	0.41	0.33	0.40	0.15	-0.17	0.52	0.40	0.28	0.26	0.49	0.32	0.43	0.48	0.05	0.10	0.11	0.11	-0.30	-0.01	0.24	0.27	0.10	-0.36	0.03	0.05	0.12	0.45	0.59	-0.30	0.24	-0.19	0.21	0.31	0.28	0.01	0.22	1.00	-0.30
BE-NL ZANDV380 [45]	-0.07	-0.19	-0.68	-0.39	-0.43	0.08	-0.41	-0.21	-0.30	-0.16	-0.07	-0.06	-0.57	-0.14	-0.50	0.08	-0.41	-0.11	-0.38	-0.10	-0.01	-0.31	-0.35	-0.35	0.45	-0.02	-0.10	-0.25	-0.11	0.00	0.00	-0.07	-0.11	-0.20	-0.23	0.07	-0.11	0.09	-0.25	-0.20	-0.01	-0.12	-0.08	-0.30	1.00

Table A.2: Correlation coefficients related to countries DE, PL, CZ, SK, HU, AT

	*DK1-TenneT [1]	[2]	[3]	[4]	*50Hertz [5]	*TenneT [6]	[7]	[8]	[9]	[10]	[11]	*DK1-TenneT [12]	[13]	[14]	[15]	*50Hertz [16]	*TenneT [17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]
DK-DE physical [1]	1.00	0.05	0.25	0.15	0.20	0.02	0.02	0.30	0.29	0.29	0.31	**1.00**	-0.31	0.15	-0.08	0.21	0.05	0.12	0.23	0.24	0.20	0.01	0.22	0.19
DE-PL physical [2]	0.05	1.00	0.43	0.51	**0.72**	-0.21	0.51	0.32	0.65	0.54	0.36	0.04	0.36	-0.47	-0.51	0.44	-0.50	**0.73**	-0.32	0.57	0.24	0.14	**0.85**	**0.76**
PL-CZ physical [3]	0.25	0.43	1.00	0.42	0.58	-0.11	0.23	0.46	0.62	0.53	0.30	0.25	-0.51	0.45	-0.35	0.53	-0.32	0.52	0.45	0.46	0.37	0.15	**0.74**	**0.85**
CZ-AT physical [4]	0.15	0.51	0.42	1.00	0.57	0.06	0.55	0.46	0.57	0.65	0.13	0.15	-0.09	-0.03	0.06	-0.01	0.16	**0.77**	0.07	0.37	0.31	0.12	0.59	0.49
DE-CZ physical [5]	0.20	**0.72**	0.58	0.57	1.00	-0.06	0.47	0.56	0.61	0.55	0.32	0.19	-0.10	-0.09	-0.50	0.55	-0.47	**0.73**	0.04	0.47	0.20	0.09	**0.81**	**0.70**
CZ-DE physical [6]	0.02	-0.21	-0.11	0.06	-0.06	1.00	0.05	0.15	-0.29	-0.13	-0.34	0.01	-0.15	0.12	0.60	-0.51	0.57	-0.18	0.20	-0.32	-0.21	-0.11	-0.14	-0.19
DE-AT physical [7]	0.02	0.51	0.23	0.55	0.47	0.05	1.00	0.31	0.39	0.44	0.17	0.01	0.14	-0.21	-0.02	0.10	-0.07	**0.79**	-0.04	0.27	0.14	0.10	0.47	0.39
PL-SK physical [8]	0.30	0.32	0.46	0.46	0.56	0.15	0.31	1.00	0.39	0.43	0.21	0.30	-0.46	0.34	-0.08	0.25	-0.05	0.51	0.49	0.34	0.20	0.09	0.59	0.31
CZ-SK physical [9]	0.29	0.65	0.62	0.57	0.61	-0.29	0.39	0.39	1.00	**0.83**	0.64	0.29	-0.12	-0.04	-0.42	0.45	-0.25	0.70	0.03	**0.86**	0.61	0.20	**0.75**	**0.72**
SK-HU physical [10]	0.29	0.54	0.53	0.65	0.55	-0.13	0.44	0.43	**0.83**	1.00	0.50	0.29	-0.14	0.00	-0.21	0.23	-0.04	0.70	0.08	0.60	0.69	0.17	0.65	0.60
HU-AT physical [11]	0.31	0.36	0.30	0.13	0.32	-0.34	0.17	0.21	0.64	0.50	1.00	0.30	-0.07	-0.10	-0.41	0.41	-0.27	0.33	-0.02	0.60	0.43	0.25	0.41	0.39
DK-DE schedule [12]	**1.00**	0.04	0.25	0.15	0.19	0.01	0.01	0.30	0.29	0.29	0.30	1.00	-0.31	0.15	-0.09	0.21	0.05	0.12	0.23	0.24	0.20	0.02	0.22	0.19
DE-PL schedule [13]	-0.31	0.36	-0.51	-0.09	-0.10	-0.15	0.14	-0.46	-0.12	-0.14	-0.07	-0.31	1.00	-0.68	-0.06	-0.19	-0.15	-0.01	-0.60	-0.06	-0.14	-0.03	-0.18	-0.17
PL-CZ schedule [14]	0.15	-0.47	0.45	-0.03	-0.09	0.12	-0.21	0.34	-0.04	0.00	-0.10	0.15	-0.68	1.00	0.21	-0.01	0.19	-0.15	**0.71**	-0.10	0.11	0.01	-0.12	-0.08
CZ-AT schedule [15]	-0.08	-0.51	-0.35	0.06	-0.50	0.60	-0.02	-0.08	-0.42	-0.21	-0.41	-0.09	-0.06	0.21	1.00	-0.70	0.67	-0.32	0.19	-0.50	-0.20	-0.10	-0.51	-0.52
DE-CZ schedule [16]	0.21	0.44	0.53	-0.01	0.55	-0.51	0.10	0.25	0.45	0.23	0.41	0.21	-0.19	-0.01	-0.70	1.00	-0.66	0.32	0.04	0.55	0.28	0.06	0.58	0.60
CZ-DE schedule [17]	0.05	-0.50	-0.32	0.16	-0.47	0.57	-0.07	-0.05	-0.25	-0.04	-0.27	0.05	-0.15	0.19	0.67	-0.66	1.00	-0.21	0.19	-0.39	-0.12	-0.03	-0.45	-0.48
DE-AT schedule [18]	0.12	**0.73**	0.52	**0.77**	**0.73**	-0.18	**0.79**	0.51	0.70	0.70	0.33	0.12	-0.01	-0.15	-0.32	0.32	-0.21	1.00	-0.01	0.50	0.29	0.18	**0.78**	0.67
PL-SK schedule [19]	0.23	-0.32	0.45	0.07	0.04	0.20	-0.04	0.49	0.03	0.08	-0.02	0.23	-0.60	**0.71**	0.19	0.04	0.19	-0.01	1.00	-0.09	0.13	0.01	-0.01	0.09
CZ-SK schedule [20]	0.24	0.57	0.46	0.37	0.47	-0.32	0.27	0.34	**0.86**	0.60	0.60	0.24	-0.06	-0.10	-0.50	0.55	-0.39	0.50	-0.09	1.00	0.67	0.11	0.64	0.57
SK-HU schedule [21]	0.20	0.24	0.37	0.31	0.20	-0.21	0.14	0.20	0.61	0.69	0.43	0.20	-0.14	0.11	-0.20	0.28	-0.12	0.29	0.13	0.67	1.00	0.03	0.33	0.35
HU-AT schedule [22]	0.01	0.14	0.15	0.12	0.09	-0.11	0.10	0.09	0.20	0.17	0.25	0.02	-0.03	0.01	-0.10	0.06	-0.03	0.18	0.01	0.11	0.03	1.00	0.16	0.16
DE-PL unsched. [23]	0.22	**0.85**	**0.74**	0.59	**0.81**	-0.14	0.47	0.59	**0.75**	0.65	0.41	0.22	-0.18	-0.12	-0.51	0.58	-0.45	**0.78**	-0.01	0.64	0.33	0.16	1.00	**0.90**
PL-CZ unsched. [24]	0.19	**0.76**	**0.85**	0.49	**0.70**	-0.19	0.39	0.31	**0.72**	0.60	0.39	0.19	-0.17	-0.08	-0.52	0.60	-0.48	0.67	0.09	0.57	0.35	0.16	**0.90**	1.00
CZ-AT unsched. [25]	0.18	**0.72**	0.56	**0.83**	**0.77**	-0.28	0.48	0.44	**0.72**	0.68	0.34	0.18	-0.05	-0.14	-0.51	0.37	-0.23	**0.84**	-0.05	0.60	0.38	0.15	**0.79**	**0.71**
DE-CZ unsched. [26]	0.09	0.56	0.34	0.69	**0.82**	0.27	0.50	0.50	0.42	0.50	0.10	0.09	0.01	-0.10	-0.12	-0.02	-0.11	0.66	0.03	0.19	0.05	0.07	0.58	0.43
CZ-DE unsched. [27]	-0.04	0.31	0.23	-0.10	0.43	0.48	0.13	0.21	-0.05	-0.10	-0.09	-0.05	-0.01	-0.08	-0.07	0.15	-0.45	0.03	0.02	0.06	-0.11	-0.09	0.33	0.30
DE-AT unsched. [28]	-0.18	-0.65	-0.59	-0.67	-0.69	0.33	-0.25	-0.50	**-0.70**	-0.66	-0.36	-0.18	0.14	0.02	0.48	-0.39	0.26	**-0.79**	-0.03	-0.53	-0.32	-0.18	**-0.76**	-0.67
PL-SK unsched. [29]	0.17	0.60	0.19	0.47	0.60	0.02	0.38	**0.77**	0.42	0.43	0.26	0.16	-0.07	-0.14	-0.24	0.26	-0.19	0.58	-0.18	0.45	0.13	0.09	0.67	0.29
CZ-SK unsched. [30]	0.16	0.29	0.44	0.49	0.38	-0.01	0.32	0.19	0.49	0.61	0.24	0.16	-0.12	0.08	0.04	-0.06	0.18	0.50	0.21	-0.02	0.05	0.20	0.37	0.45
SK-HU unsched. [31]	0.20	0.51	0.36	0.58	0.56	0.03	0.47	0.39	0.53	0.69	0.26	0.20	-0.06	-0.11	-0.09	0.04	0.06	0.67	-0.02	0.15	-0.05	0.20	0.57	0.47
HU-AT unsched. [32]	0.27	0.23	0.17	0.04	0.22	-0.23	0.08	0.13	0.44	0.34	**0.73**	0.26	-0.04	-0.09	-0.30	0.33	-0.22	0.18	-0.03	0.46	0.37	-0.48	0.26	0.24
DE price [33]	0.23	-0.22	0.27	-0.13	-0.07	-0.06	-0.40	0.11	-0.01	-0.10	0.06	0.23	-0.41	0.40	-0.09	0.15	-0.04	-0.21	0.33	0.03	0.03	-0.07	0.00	0.07
PL price [34]	0.08	-0.07	0.19	-0.11	-0.03	-0.20	-0.35	0.01	0.01	-0.10	0.07	0.08	-0.15	0.21	-0.20	0.17	-0.16	-0.16	0.17	0.06	0.06	-0.09	0.01	0.08
CZ price [35]	0.22	-0.16	0.32	-0.15	0.00	-0.12	-0.40	0.13	0.03	-0.09	0.10	0.22	-0.39	0.40	-0.19	0.24	-0.14	-0.18	0.33	0.08	0.06	-0.07	0.05	0.13
SK price [36]	0.21	-0.11	0.33	-0.13	0.02	-0.13	-0.38	0.12	0.06	-0.06	0.12	0.21	-0.36	0.37	-0.22	0.25	-0.15	-0.15	0.30	0.11	0.07	-0.06	0.08	0.16
DE wind [37]	-0.15	0.48	0.30	0.39	0.55	0.26	0.32	0.25	0.23	0.28	0.01	-0.15	0.08	-0.14	-0.11	0.10	-0.16	0.39	-0.03	0.12	0.08	0.03	0.47	0.42
DE pv [38]	-0.02	0.03	0.02	0.13	-0.12	-0.40	0.08	-0.10	0.16	0.18	0.10	-0.03	0.05	-0.04	-0.07	0.03	-0.01	0.13	-0.06	0.12	0.19	0.13	0.00	0.04
DK wind [39]	0.01	0.36	0.20	0.28	0.41	0.18	0.25	0.26	0.13	0.17	-0.01	0.00	0.07	-0.07	-0.07	0.07	-0.13	0.29	0.00	0.06	0.01	0.03	0.34	0.27
PL wind [40]	0.01	0.32	0.17	0.30	0.44	0.25	0.28	0.28	0.21	0.28	0.09	0.00	0.00	-0.11	-0.06	0.09	-0.03	0.31	0.01	0.14	0.09	0.06	0.33	0.25
DE other gen. [41]	0.14	-0.10	0.16	-0.19	0.01	0.07	-0.20	0.09	0.01	-0.02	0.11	0.14	-0.22	0.22	-0.08	0.09	-0.03	-0.13	0.18	-0.02	0.00	0.01	0.02	0.05
PL other gen. [42]	0.19	-0.01	0.50	0.01	0.15	0.07	-0.14	0.34	0.14	0.11	0.15	0.18	-0.46	0.46	-0.10	0.19	-0.07	0.05	0.47	0.07	0.10	0.02	0.24	0.29
CZ other gen. [43]	0.08	0.01	0.25	0.15	0.04	0.58	0.12	0.34	0.04	0.06	-0.01	0.08	-0.26	0.25	0.29	-0.21	0.29	0.09	0.36	-0.01	0.00	-0.03	0.15	0.13
HU other gen. [44]	0.03	0.11	0.40	0.06	0.19	0.23	0.03	0.25	0.06	-0.01	0.01	0.02	-0.24	0.25	-0.03	0.10	-0.07	0.11	0.32	0.00	-0.04	-0.01	0.25	0.30
AT other gen. [45]	0.19	-0.15	0.22	-0.31	-0.04	0.04	-0.42	0.15	0.00	-0.04	0.19	0.18	-0.33	0.29	-0.14	0.18	-0.08	-0.28	0.30	0.02	0.06	0.04	0.03	0.08
DE north-south [46]	0.15	0.49	0.55	0.50	0.66	0.46	0.40	0.49	0.34	0.36	0.08	0.15	-0.19	0.09	-0.03	0.17	-0.08	0.48	0.20	0.22	0.13	-0.03	0.62	0.56
PL north-south [47]	-0.12	0.15	-0.18	0.23	0.15	0.20	0.42	0.01	0.00	0.08	-0.10	-0.12	0.24	-0.25	0.16	-0.13	0.08	0.21	-0.19	0.01	0.01	-0.03	0.03	-0.05
PL Krajnik-Plew. [48]	0.20	0.60	0.41	0.48	0.69	-0.05	0.34	0.41	0.49	0.47	0.30	0.20	0.01	-0.13	-0.35	0.34	-0.31	0.55	-0.02	0.39	0.22	0.07	0.63	0.54

	[25]	*50Hertz [26]	*TenneT [27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	*50Hertz [37]	*TenneT [38]	[39]	[40]	*50Hertz [41]	[42]	[43]	[44]	[45]	[46]	[47]	[48]
DK-DE physical [1]	0.18	0.09	-0.04	-0.18	0.17	0.16	0.20	0.27	0.23	0.08	0.22	0.21	-0.15	-0.02	0.01	0.01	0.14	0.19	0.08	0.03	0.19	0.15	-0.12	0.20
DE-PL physical [2]	**0.72**	0.56	0.31	-0.65	0.60	0.29	0.51	0.23	-0.22	-0.07	-0.16	-0.11	0.48	0.03	0.36	0.32	-0.10	-0.01	0.01	0.11	-0.15	0.49	0.15	0.60
PL-CZ physical [3]	0.56	0.34	0.23	-0.59	0.19	0.44	0.36	0.17	0.27	0.19	0.32	0.33	0.30	0.02	0.20	0.17	0.16	0.50	0.25	0.40	0.22	0.55	-0.18	0.41
CZ-AT physical [4]	**0.83**	0.69	-0.10	-0.67	0.47	0.49	0.58	0.04	-0.13	-0.11	-0.15	-0.13	0.39	0.13	0.28	0.30	-0.19	0.01	0.15	0.06	-0.31	0.50	0.23	0.48
DE-CZ physical [5]	**0.77**	**0.82**	0.43	-0.69	0.60	0.38	0.56	0.22	-0.07	-0.03	0.00	0.02	0.55	-0.12	0.41	0.44	0.01	0.15	0.04	0.19	-0.04	0.66	0.15	0.69
CZ-DE physical [6]	-0.28	0.27	0.48	0.33	0.02	-0.01	0.03	-0.23	-0.06	-0.20	-0.12	-0.13	0.26	-0.40	0.18	0.25	0.07	0.07	0.58	0.23	0.04	0.46	0.20	-0.05
DE-AT physical [7]	0.48	0.50	0.13	-0.25	0.38	0.32	0.47	0.08	-0.40	-0.35	-0.40	-0.38	0.32	0.08	0.25	0.28	-0.20	-0.14	0.12	0.03	-0.42	0.40	0.42	0.34
PL-SK physical [8]	0.44	0.50	0.21	-0.50	**0.77**	0.19	0.39	0.13	0.11	0.01	0.13	0.12	0.25	-0.10	0.26	0.28	0.09	0.34	0.34	0.25	0.15	0.49	0.01	0.41
CZ-SK physical [9]	**0.72**	0.42	-0.05	**-0.70**	0.42	0.49	0.53	0.44	-0.01	0.01	0.03	0.06	0.23	0.16	0.13	0.21	0.01	0.14	0.04	0.06	0.00	0.34	0.00	0.49
SK-HU physical [10]	0.68	0.50	-0.10	-0.66	0.43	0.61	0.69	0.34	-0.10	-0.10	-0.09	-0.06	0.28	0.18	0.17	0.28	-0.02	0.11	0.06	-0.01	-0.04	0.36	0.08	0.47
HU-AT physical [11]	0.34	0.10	-0.09	-0.36	0.26	0.24	0.26	**0.73**	0.06	0.07	0.10	0.12	0.01	0.10	-0.01	0.09	0.11	0.15	-0.01	0.01	0.19	0.08	-0.10	0.30
DK-DE schedule [12]	0.18	0.09	-0.05	-0.18	0.16	0.16	0.20	0.26	0.23	0.08	0.22	0.21	-0.15	-0.03	0.00	0.00	0.14	0.18	0.08	0.02	0.18	0.15	-0.12	0.20
DE-PL schedule [13]	-0.05	0.01	-0.01	0.14	-0.07	-0.12	-0.06	-0.04	-0.41	-0.15	-0.39	-0.36	0.08	0.05	0.07	0.00	-0.22	-0.46	-0.26	-0.24	-0.33	-0.19	0.24	0.01
PL-CZ schedule [14]	-0.14	-0.10	-0.08	0.02	-0.14	0.08	-0.11	-0.09	0.40	0.21	0.40	0.37	-0.14	-0.04	-0.07	-0.11	0.22	0.46	0.25	0.25	0.29	0.09	-0.25	-0.13
CZ-AT schedule [15]	-0.51	-0.12	-0.07	0.48	-0.24	0.04	-0.09	-0.30	-0.09	-0.20	-0.19	-0.22	-0.11	-0.07	-0.07	-0.06	-0.08	-0.10	0.29	-0.03	-0.14	-0.03	0.16	-0.35
DE-CZ schedule [16]	0.37	-0.02	0.15	-0.39	0.26	-0.06	0.04	0.33	0.15	0.17	0.24	0.25	0.10	0.03	0.07	0.09	0.09	0.19	-0.21	0.10	0.18	0.17	-0.13	0.34
CZ-DE schedule [17]	-0.23	-0.11	-0.45	0.26	-0.19	0.18	0.06	-0.22	-0.04	-0.16	-0.14	-0.15	-0.16	-0.01	-0.13	-0.03	-0.03	-0.07	0.29	-0.07	-0.08	-0.08	0.08	-0.31
DE-AT schedule [18]	**0.84**	0.66	0.03	**-0.79**	0.58	0.50	0.67	0.18	-0.21	-0.16	-0.18	-0.15	0.39	0.13	0.29	0.31	-0.13	0.05	0.09	0.11	-0.28	0.48	0.21	0.55
PL-SK schedule [19]	-0.05	0.03	0.02	-0.03	-0.18	0.21	-0.02	-0.03	0.33	0.17	0.33	0.30	-0.03	-0.06	0.00	0.01	0.18	0.47	0.36	0.32	0.30	0.20	-0.19	-0.02
CZ-SK schedule [20]	0.60	0.19	0.06	-0.53	0.45	-0.02	0.15	0.46	0.03	0.06	0.08	0.11	0.12	0.12	0.06	0.14	-0.02	0.07	-0.01	0.00	0.02	0.22	0.01	0.39
SK-HU schedule [21]	0.38	0.05	-0.11	-0.32	0.13	0.05	-0.05	0.37	0.03	0.06	0.06	0.07	0.08	0.19	0.01	0.09	0.00	0.10	0.00	-0.04	0.06	0.13	0.01	0.22
HU-AT schedule [22]	0.15	0.07	-0.09	-0.18	0.09	0.20	0.20	-0.48	-0.07	-0.09	-0.07	-0.06	0.03	0.13	0.03	0.06	0.01	0.02	-0.03	-0.01	0.04	-0.03	-0.03	0.07
DE-PL unsched. [23]	**0.79**	0.58	0.33	**-0.76**	0.67	0.37	0.57	0.26	0.00	0.01	0.05	0.08	0.47	0.00	0.34	0.33	0.02	0.24	0.15	0.25	0.03	0.62	0.03	0.63
PL-CZ unsched. [24]	**0.71**	0.43	0.30	-0.67	0.29	0.45	0.47	0.24	0.07	0.08	0.13	0.16	0.42	0.04	0.27	0.25	0.05	0.29	0.13	0.30	0.08	0.56	-0.05	0.54
CZ-AT unsched. [25]	1.00	0.66	-0.05	**-0.85**	0.53	0.40	0.55	0.20	-0.06	0.01	-0.02	0.01	0.40	0.15	0.28	0.30	-0.12	0.07	-0.03	0.07	-0.19	0.45	0.11	0.61
DE-CZ unsched. [26]	0.66	1.00	0.41	-0.55	0.54	0.50	0.64	0.04	-0.19	-0.16	-0.16	-0.15	0.59	-0.17	0.45	0.46	-0.05	0.05	0.19	0.16	-0.18	0.67	0.27	0.60
CZ-DE unsched. [27]	-0.05	0.41	1.00	0.09	0.22	-0.20	-0.04	-0.02	-0.02	-0.05	0.02	0.02	0.45	-0.43	0.33	0.30	0.10	0.16	0.32	0.33	0.14	0.58	0.14	0.27
DE-AT unsched. [28]	**-0.85**	-0.55	0.09	1.00	-0.54	-0.48	-0.58	-0.20	-0.07	-0.10	-0.11	-0.13	-0.30	-0.12	-0.22	-0.22	0.00	-0.23	-0.03	-0.14	0.02	-0.36	0.09	-0.53
PL-SK unsched. [29]	0.53	0.54	0.22	-0.54	1.00	0.06	0.46	0.17	-0.12	-0.11	-0.09	-0.08	0.30	-0.07	0.29	0.31	-0.04	0.04	0.12	0.05	-0.06	0.41	0.15	0.48
CZ-SK unsched. [30]	0.40	0.50	-0.20	-0.48	0.06	1.00	**0.78**	0.08	-0.07	-0.09	-0.08	-0.07	0.24	0.11	0.15	0.18	0.05	0.15	0.10	0.12	-0.04	0.29	-0.02	0.28
SK-HU unsched. [31]	0.55	0.64	-0.04	-0.58	0.46	**0.78**	1.00	0.09	-0.17	-0.20	-0.18	-0.16	0.31	0.05	0.23	0.30	-0.02	0.05	0.09	0.04	-0.11	0.37	0.10	0.42
HU-AT unsched. [32]	0.20	0.04	-0.02	-0.20	0.17	0.08	0.09	1.00	0.10	0.12	0.14	0.15	-0.01	0.00	-0.03	0.04	0.10	0.12	0.01	0.02	0.15	0.09	-0.08	0.22
DE price [33]	-0.06	-0.19	-0.02	-0.07	-0.12	-0.07	-0.17	0.10	1.00	**0.75**	**0.92**	**0.87**	-0.30	0.09	-0.16	-0.31	0.46	0.70	0.37	0.48	0.58	0.03	-0.65	-0.02
PL price [34]	0.01	-0.16	-0.05	-0.10	-0.11	-0.09	-0.20	0.12	**0.75**	1.00	**0.81**	**0.78**	-0.21	0.20	-0.12	-0.30	0.35	0.64	0.27	0.47	0.51	0.00	-0.62	0.08
CZ price [35]	-0.02	-0.16	0.02	-0.11	-0.09	-0.08	-0.18	0.14	**0.92**	**0.81**	1.00	**0.95**	-0.27	0.11	-0.13	-0.29	0.47	**0.74**	0.35	0.50	0.62	0.05	-0.68	0.04
SK price [36]	0.01	-0.15	0.02	-0.13	-0.08	-0.07	-0.16	0.15	**0.87**	**0.78**	**0.95**	1.00	-0.25	0.10	-0.12	-0.27	0.44	**0.71**	0.34	0.49	0.59	0.06	-0.65	0.06
DE wind [37]	0.40	0.59	0.45	-0.30	0.30	0.24	0.31	-0.01	-0.30	-0.21	-0.27	-0.25	1.00	-0.13	0.57	0.69	-0.39	-0.05	0.12	0.13	-0.16	0.57	0.41	0.60
DE pv [38]	0.15	-0.17	-0.43	-0.12	-0.07	0.11	0.05	0.00	0.09	0.20	0.11	0.10	-0.13	1.00	-0.02	-0.10	-0.10	0.15	-0.20	-0.06	0.14	-0.30	-0.30	0.08
DK wind [39]	0.28	0.45	0.33	-0.22	0.29	0.15	0.23	-0.03	-0.16	-0.12	-0.13	-0.12	0.57	-0.02	1.00	0.47	-0.17	0.05	0.14	0.16	-0.02	0.45	0.23	0.48
PL wind [40]	0.30	0.46	0.30	-0.22	0.31	0.18	0.30	0.04	-0.31	-0.30	-0.29	-0.27	0.69	-0.10	0.47	1.00	-0.26	-0.13	0.05	-0.01	-0.11	0.38	0.47	0.49
DE other gen. [41]	-0.12	-0.05	0.10	0.00	-0.04	0.05	-0.02	0.10	0.46	0.35	0.47	0.44	-0.39	-0.10	-0.17	-0.26	1.00	0.54	0.37	0.41	0.54	0.04	-0.57	-0.14
PL other gen. [42]	0.07	0.05	0.16	-0.23	0.04	0.15	0.05	0.12	0.70	0.64	**0.74**	**0.71**	-0.05	0.15	0.05	-0.13	0.54	1.00	0.66	**0.77**	**0.76**	0.26	**-0.75**	0.17
CZ other gen. [43]	-0.03	0.19	0.32	-0.03	0.12	0.10	0.09	0.01	0.37	0.27	0.35	0.34	0.12	-0.20	0.14	0.05	0.37	0.66	1.00	**0.73**	0.45	0.45	-0.28	0.10
HU other gen. [44]	0.07	0.16	0.33	-0.14	0.05	0.12	0.04	0.02	0.48	0.47	0.50	0.49	0.13	-0.06	0.16	-0.01	0.41	**0.77**	**0.73**	1.00	0.55	0.40	-0.45	0.17
AT other gen. [45]	-0.19	-0.18	0.14	0.02	-0.06	-0.04	-0.11	0.15	0.58	0.51	0.62	0.59	-0.16	0.14	-0.02	-0.11	0.54	**0.76**	0.45	0.55	1.00	0.01	-0.69	0.05
DE north-south [46]	0.45	0.67	0.58	-0.36	0.41	0.29	0.37	0.09	0.03	0.00	0.05	0.06	0.57	-0.30	0.45	0.38	0.04	0.26	0.45	0.40	0.01	1.00	0.19	0.52
PL north-south [47]	0.11	0.27	0.14	0.09	0.15	-0.02	0.10	-0.08	-0.65	-0.62	-0.68	-0.65	0.41	-0.30	0.23	0.47	-0.57	**-0.75**	-0.28	-0.45	-0.69	0.19	1.00	0.21
PL Krajnik-Plew. [48]	0.61	0.60	0.27	-0.53	0.48	0.28	0.42	0.22	-0.02	0.08	0.04	0.06	0.60	0.08	0.48	0.49	-0.14	0.17	0.10	0.17	0.05	0.52	0.21	1.00

APPENDIX B: METHODOLOGY FOR MODEL ANALYSIS

In this appendix we describe in more detail the model that was applied in the assessment of measures and data assumptions used in the analysis.

B.1 The-MA – model description

The-MA is an advanced power market simulations model developed by THEMA Consulting Group. The model is a fundamental market model that optimizes generation dispatch under a set of constraints. While it takes into account ATC restrictions on cross-border flows, it is not a physical grid model, but models scheduled (market) flows. Hence The-MA is able to yield quantitative estimates for *market consequences* of different measures.

The main features of the model are:

- *Hourly time resolution*: The model simulates all hours of a year in chronological order. This is an important aspect in order to capture the implications of intermittent generation on the power markets.
- *Detailed representation on thermal units*: Thermal generation modelling includes start-up costs, part-load efficiencies and minimum stable load.
- *Accounting for volatility of wind, PV, and other intermittent generation*: The current generation mix in Europe is already characterized by large shares of renewable generation like wind and photo voltaic (PV), and these shares are likely to increase even further in the future. These types of generation have in common that they are volatile. In The-MA, these sources of generation are modelled with observed volatility, based on historical wind and PV data.
- *Modelling of the integrated North-European electricity market including transmission capacities:* The geographic focus of the model applied in this project is Central Europe.
- *Detailed reservoir modelling:* Large hydro reservoirs can be modelled individually, taking into account minimum release constraints and reservoir restrictions.

The model is a fundamental market model. This means that it minimizes generation costs under a set of constraints, and by this mimics perfectly competitive markets. In a perfectly competitive market, the market outcome is equivalent to cost-minimizing solution.

The total system costs are defined as the total costs of generation, accounting for start-up costs and part-load efficiencies. The set of constraints include:

- Demand constraint: in each hour, the demand has to be lower than the generation + imports reduced by losses – exports for each zone in the model. It also includes demand from pumping plants and generation from pumping plants. Generation from pumping plants is corrected for losses. *The shadow value on this constraint is the price in that zone in that hour.*
- Reservoir level constraint: This is an inter-temporal constraint linking different time periods (typically weeks) within the model. The constraint says that the reservoir level in a time period is the reservoir level in the previous time period – generation in the time period + inflow in the time period – spill in the time period. The end of the last time period in the model is identified with the beginning of the first time period, so that the constraints create a "circle" connecting all time periods with each other. This also ensures that the generation plus spill is given by the inflow.

  For the start week, the reservoir starting level is given if the user defines a starting value.
- Lower generation bound for thermal units: for each hour, there are two decision variables for plants with start-up costs; the actual generation, and the capacity that is online. Then, for each hour, the minimum generation is given by the minimum load factor, multiplied with

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the online capacity in this hour. Thus, in order to generate less, the online capacity has to be reduced, which in turn increases start-up costs in the next period.

- For each hour, the maximum generation is bound by the online capacity. Thus, in order to produce more, the model may have to increase the online capacity, which induces start-up costs.
- The capacity started in an hour (which then determines the start-up costs), is given by the online capacity in that hour minus the online capacity in the previous hour.

The above constraints are constraints that relate endogenous variables with each other, for example generation and imports, or reservoir filling in one period with reservoir filling in another period.

Other constraints include:

- The generation in an hour is bound by the capacity, corrected for availability.
- The fixed generation in an hour is given by installed capacity, multiplied with the respective fixed profile for that hour.
- The minimum generation (not to be confused with the minimum load factor) is the installed capacity, multiplied with the minimum profile for that hour.
- The maximum trade in an hour is the installed capacity, corrected for availability.
- The reservoir level is bound by the reservoir size.

The overall welfare function that is minimizes can then be described as follows:

$$\sum_{hours,\ plants} (\text{Generation} * (\text{Fuel costs} + \text{carbon costs} + \text{variable oper. costs})$$
$$+Start\_up\ costs + corrections\ for\ part\_load\ generation)\ )$$

The approach for modelling start-up costs and part-load efficiencies is based on Weber, C. (2004): “Uncertainties in the electric power industry: methods and models for decision support”, Springer, 2004. It is an approach to capture start-up costs by a linear approximation.

The model itself uses Excel as a front-interface to handle inputs and outputs. The actual optimization routines are programmed in GAMS, using CPLEX as a solver. GAMS stands for General Algebraic Modelling System, and is a high-level modelling system for mathematical programming and optimization.

B.2 Detailed numerical assumptions

In the following we present the main assumptions for the 2013 reference case.

Transmission zones for the bidding zone delimitation scenarios

In order to investigate the bidding zone delimitation measure, we divided Germany into two transmission zones, as well as treating Austria as a separate price zone. Germany was split according to the following distribution of Bunderländer:

- *Northern Germany*: Niedersachsen, Schleswig Holstein, Hamburg, Bremen, Mecklenburg Vorpommern, Thüringen, Brandenburg and Berlin, Sachsen and Sachsen Anhalt
- *Southern Germany*: Bayern, Baden Württemberg., Rheinland Pfalz, Saarland, Nordrhein-Westfalen, and Hessen.

Multiple sources acknowledge bottleneck between the north and the south, especially on the line Remptendorf-Redwitz. Our split is mainly based on the *Regionenmodell (*Amprion, EnBW, Transpower, Vattenfall (2009), *Regionenmodell Stromtransport).* The Regionenmodell gives an overview of load flows and potential congestions, as well as a regional distribution of generation capacity and load.

Implementation of ATC reduction

We modelled this measure by reducing ATC from Germany to the Netherlands by 20% flat throughout the year. This implies a decrease from max capacity of 1500 MW to 1200 MW.

Implementation of curtailment

We have modelled both wind curtailment and thermal curtailment as a measure to reduce the problems caused from transit flows going originating from the northern part of Germany. In order to model curtailment, we have reduced the wind feed-in and thermal generation respectively in selected hours where internal bidding zones yield price differences (for an internal ATC value of 13 GW).

We first identified some 441 hours of price difference between northern and southern Germany that occur in the bidding zone delimitation scenario under the assumption of an internal ATC of 13 GW. Secondly we reduce wind generation in those hours where the price differences occur. In these hours, output was reduced to 45% for onshore wind and to 80% for offshore wind. This yields an effective wind curtailment corresponding to the volume of 3.4 TWh. This volume is slightly reduced by more North-German coal production resulting from a price increase, netting out to reduced total generation of roughly 3 TWh.

As it might be just as likely an option to reduce flexible thermal generation in those same hours, we also simulated the effect of curtailing thermal generation. We reduced output from coal and lignite plants in the same hours, corresponding to an output reduction of roughly 3 TWh

Implementation of new DC lines

We modelled a 4 GW DC line between north and south Germany. Utilization was defined by wind feed-in in northern Germany. The utilization was 100% whenever the wind feed-in was above average wind feed-in. For hours with wind feed-in below average, the utilization was a linear interpolation between zero and 100% according to the ratio of wind feed-in and average wind feed-in. In order to give results in the market model, this measure was modelled under the assumption of price zone delimitation, with an internal ATC of 13 GW in Germany.

Demand

Assumptions on gross demand are summarized in Table A.3, and are based on data from EUROSTAT.

Table A.3: Demand assumptions (TWh)

	2013
Norway	**127.0**
Sweden	**142.1**
Finland	**85.1**
Denmark	**36.1**
Germany_North	**187.5**
Germany_South	**375.4**
Great_Britain	**354.3**
Netherlands	**117.3**
Poland	**144.0**
France	**474.1**
Belgium	**87.6**
Austria	**66.7**
Switzerland	**67.1**

Czech_Republic	62.8
Slovakia	29.8
Italy	352.3

Source: EUROSTAT

To split between price zones; northern Germany and southern Germany, we apply the load factors per region in the Regionenmodell. Thus, for each transmission zone we calculate the relative share of load, based on the zone definition (using data for those regions that fit into the respectively defined transmission zones we apply). This share is then used to allocate total demand.

Generation capacity

Assumptions for generation capacities are shown in Table A.4.

Table A.4: Generation capacity assumptions (note: coal includes lignite)

	units	*Coal*	*Gas*	*CHP*	*Wind*	*Solar*	*Hydro*	*Nuclear*
Norway	*MW*	0	978	435	740	0	34181	0
Sweden	*MW*	336	2405	4525	4582	0	18037	9646
Finland	*MW*	3002	2510	4052	288	0	4508	2646
Denmark	*MW*	4258	1775	2043	4682	0	0	0
Germany_North	*MW*	17377	8592	4823	25462	10313	210	4095
Germany_South	*MW*	31060	14202	7071	7721	24065	4790	7947
Great_Britain	*MW*	22604	29857	12463	10160	1655	178	11343
Netherlands	*MW*	3819	14648	4573	2391	229	0	475
Poland	*MW*	27872	1472	688	2699	0	2221	0
France	*MW*	6590	10640	6536	7564	0	34000	62580
Belgium	*MW*	1956	6896	2727	1430	0	1300	5737
Austria	*MW*	1212	3451	2703	1621	0	11000	0
Switzerland	*MW*	0	563	354	0	0	13500	3175
Czech_Republic	*MW*	10587	2636	508	260	1670	1086	5608
Slovakia	*MW*	2026	1658	773	150	0	1660	2637
Italy	*MW*	13576	48484	31696	7760	4526	16946	0

To allocate the capacities between price zones we used the Platts database for thermal generation. The database includes information about each federal state of Germany. As for the RES generation and capacities we apply splits, derived from the Germany grid development plan (GE: Szenariorahmen für den Netzentwicklungsplan 2013). This includes allocation of RES type per federal state.

Fuel and CO_2 price assumptions

An overview of our fuel price assumptions is given in the table below. For gas, coal and CO_2 prices, our assumptions are based on today’s price level and futures for today (cf. eex.com).

Table A.5: Fuel price assumptions

Fuel	*units*	*2013*
Coal	*$ per ton*	**75.7**
Gas	*$ per MBtu*	**10.1**
CO_2	*€ per ton*	**4.5**

ATC assumptions

Our ATC assumptions, shown in Table A.6, are based on ENTSO-Es NTC Matrix and the ENTSO-E Transparency Platform (entsoe.net). As shown in the table, the ATC levels between Austria and Germany and in Germany internally are set to approximately infinite. This is what we apply in the reference scenario.

When modelling bidding zone delimitation we apply an ATC level between Germany and Austria of 5.000 MW. For Germany internally we have modelled a range of alternative ATC levels, due to the uncertainty. Between northern and southern Germany we model four different ATC levels; 7.000, 10.000, 13.000, 16.000 MW. ENTSO-E has publicly available data on transmission capacities between the cross-borders of countries, though not capacity per line. Transmission capacities from German zones to countries outside are based on the total capacity given by ENTSO-E and visual allocation of lines (according to ENTSO-E transmission map). For data between zones, the ENTSO-E map was applied by using the identified types and number of transmission lines to estimate the internal cross-zones capacities. For Germany, both the Regionenmodell and the ENTSO-E transmission map have been used, to estimate the capacity.

Table A.6: Allocated Transmission capacity assumptions (MW)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]
External [1]	-	56	-	3 110	-	-	-	-	-	400	500	-	1 475	-	-	1 500	-
Norway [2]	-	-	25 000	25 000	1 000	-	-	700	-	-	-	-	-	-	-	-	-
Sweden [3]	-	25000	-	25 000	1 810	605	-	-	600	-	-	-	-	-	-	-	-
Finland [4]	350	25 000	25 000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Denmark [5]	-	1 000	2 255	-	-	2 568	-	-	-	-	-	-	-	-	-	-	-
Ger_North [6]	-	-	600	-	2 075	-	*100 000*	1 500	1000	-	-	-	-	-	400	-	-
Ger_South [7]	-	-	-	-	-	*100 000*	-	1 500	-	-	3 200	-	*100 000*	1 780	400	-	-
Netherlands [8]	-	700	-	-	-	1 900	1900	-	-	1 000	-	2 300	-	-	-	-	-
Poland [9]	-	-	600	-	-	1 150	-	-	-	-	-	-	-	-	1 850	600	-
Great Britain [10]	400	-	-	-	-	-	-	1 000	-	-	2 000	-	-	-	-	-	-
France [11]	1 250	-	-	-	-	-	2650	-	-	2 000	-	3 150	-	3 100	-	-	2 488
Belgium [12]	-	-	-	-	-	-	-	2 350	-	-	1 800	-	-	-	-	-	-
Austria [13]	1 550	-	-	-	-	-	*100 000*	-	-	-	-	-	-	505	600	-	210
Switzerland [14]	-	-	-	-	-	-	3 950	-	-	-	1 100	-	1 100	-	-	-	3 813
Czech Republic [15]	-	-	-	-	-	1 150	1 150	-	850	-	-	-	900	-	-	1 200	-
Slovakia [16]	1 500	-	-	-	-	-	-	-	500	-	-	-	-	-	1 200	-	400
Italy [17]	-	-	-	-	-	-	-	-	-	-	933	-	178	1 625	-	180	-