

## Lucrative Bottlenecks

The electricity trade across borders in Europe is important for the utilization of an increasing intermittent production from wind farms and solar cells. Several electricity markets have been developed in order to organize electricity trade efficiently. Market couplings have the purpose to facilitate trade between markets.

The price levels in the European wholesale markets are very different. The main reasons are trade barriers, mainly from bottlenecks in the grids and from less efficient market arrangements.

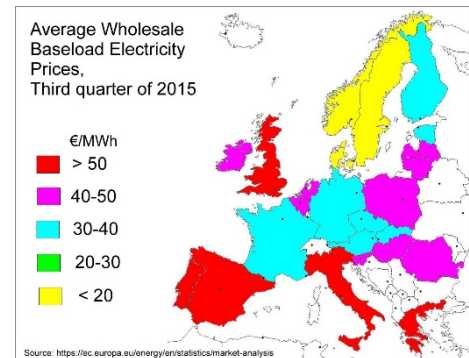


Fig. 1 - Large price differences in Europe

Transfer of electricity through grid bottlenecks is charged with *bottleneck fees* or *congestion fees*. The purpose of this note is to explain the principle and to show the magnitude of bottleneck fees for the Danish interconnections.

### The Principle of Congestion Fees

Assume that we have two production units. The electricity demand is 150 MW. The optimal load dispatch is 100 MW for unit 1 and 50 MW for unit 2. The total cost for one hour is € 1,750 or  $1,750/150 = 11.67$  €/MWh.

	Capacity	Production cost
	MW	€/MWh
Unit 1	100	10
Unit 2	100	15

Table 1 - Production system

Unit 2 has 50 MW free capacity. The cost of increasing the demand by one MW is 15 €/MWh. This is the incremental cost of the system.

If the producers use their incremental cost as bids to the market, the incremental cost will also be *the spot price* (15 €/MWh) for that hour. The contribution margin for unit 1 is  $100 \times (15 - 10) = 500$  € and  $50 \times (15 - 15) = 0$  € for unit 2.

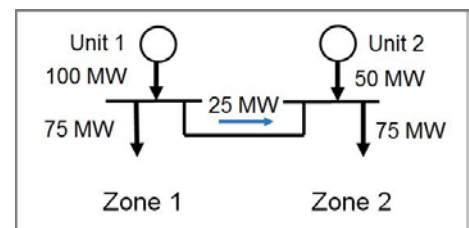


Fig. 2 - Optimum without bottlenecks

Now we assume that there are two zones. Unit 1 is located in zone 1 and unit 2 is located in zone 2. The demand is 75 MW for each zone. For the optimal load dispatch without bottlenecks, 25 MW flows from zone 1 to zone 2 (fig. 2). The load dispatch, the total cost and the money flows are unchanged.

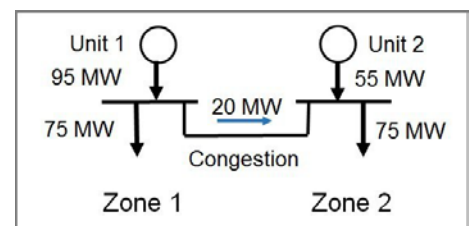


Fig. 3 - Bottleneck between zone 1 and 2

A transfer limit at 20 MW will change the load dispatch. The production on unit 1 is limited to 95 MW. The production on unit 2 is correspondingly higher. The total cost is  $95 \times 10 + 55 \times 15 = 1,775$  MW. There is free capacity on both units. The spot price will be 10 €/MWh in zone 1 and 15 €/MWh in zone 2.

The flow of money explains the origin of the congestion fee. The market buys 20 MW for 200 € in zone 1 and sells the same 20 MW for 300 € in zone 2. The surplus is 100 €, which goes to the grid owner or grid owners as a congestion fee.

	Zone 1		Zone 2		Total
Local price	10 €/MWh		15 €/MWh		
Sold from local units	95 MW	950 €	55 MW	825 €	1,775 €
+ Import/export	-20 MW	-200 €	+20 MW	+300 €	+100 €
= Total local sale	75 MW	750 €	75 MW	1,125 €	1,825 €

Table 2 - Flow of money for the case in fig. 3

## The Congestion Fee Depends on Declared Transfer Capability

Table 3 shows supplier's revenues, buyer's cost and congestion fee for different transfer capabilities.

Max transfer	Suppliers' revenue	Congestion fee	Buyers' cost
25	1,750	0	1,750
20	1,775	100	1,875
10	1,825	50	1,875
0	1,875	0	1,875

Table 3 - Effects of varying exchange capacity

The general characteristic of the congestion fee is that it is *zero for the two ends of the scale: no limitation and no transfer*.

Table 3 demonstrates that bottlenecks are expensive to the demand side, while grid owners have an income at congestion levels between no transfer and no limits.

For simplicity, this case was based on two supply sources with constant prices. *Supply curves*<sup>1</sup> normally have a positive slope.

Fig. 4 shows a more realistic, but still idealized case. For this demonstration, demand is assumed inelastic.

If the units are located in two different zones without interconnection, the marginal costs will be different. If the demand is 75 MW for each zone, the marginal costs will be 15.30 €/MWh in zone 1 and 18.50 €/MWh in zone 2 (red dots in fig. 4). The price gap is  $18.50 - 15.30 = 3.20$  €/MWh.



Fig. 4 - Two units with increasing supply curves

When the two areas are interconnected, the price difference will drive electricity from zone 1 to zone 2 until the prices are equal. The optimal dispatch is 100 MW on unit 1 and 50 MW on unit 2.

The common marginal cost is 17.00 €/MWh (white operating points in fig. 4). In this case, the condition is the exchange of 25 MW from zone 1 to zone 2.

If the capacity of the interconnection is reduced from the 25 MW, the price gap will increase until 3.20 €/MWh at zero exchange.

The congestion fee (transfer × price gap) will have a maximum value somewhere between zero exchange and maximum exchange (fig. 5).

<sup>1</sup> A supply curves shows the *incremental cost* or *marginal cost* for the range of supply.

The essential point is that there is a maximum fee at a certain exchange capacity.

**The TSOs set the Transfer Limits**

In most European countries, the owners of the primary transmission grids are the national transmission system operators (TSO). The operational security is the main consideration when the TSOs set transmission limits.

In some cases, the limitations at the borders reflect internal bottlenecks in the grids and not the capacity at the border itself. In such cases, the market operation leads to a non-optimal solution, and a market redesign should be considered.

It was the case at the border between East Denmark (DKE) and Sweden until 2010, when the Swedish electricity market was divided into four price zones.

Germany, Austria and Luxemburg make one price zone with internal bottlenecks. Germany has four TSOs. Due to internal congestions in Germany, the exchange limits from West Denmark (DKW) to Germany was set to zero in 58% of the hours in 2015 though the technical capacity at the border is 1600 MW.

**Danish Congestion Income 2011-2014**

Each link between two price zones can generate a congestion income. When the link connects two TSOs, they share the congestion income from the link in accordance with their agreements.

There are considerable differences in congestion income for year to year. The Danish interconnections generated between 813 m DKK and 1,748 m DKK per year from 2011 to 2015<sup>2</sup>.

The Energinet.dk shares were 533 m DKK in 2014 and 856 m DKK in 2012. The annual accounts for 2015 have not yet been published.

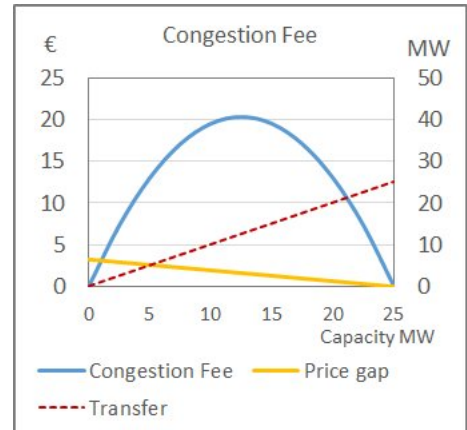


Fig. 5 - The congestion fee is transfer multiplied by price gap

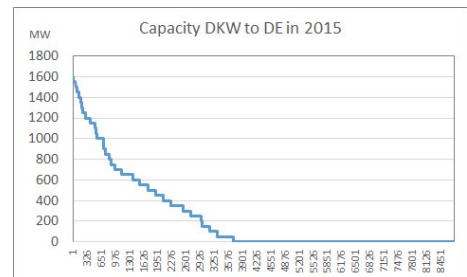


Fig. 6 - Duration curve for transfer capacity from DKW to Germany in 2015 (zero in 5081 hours in 2015)

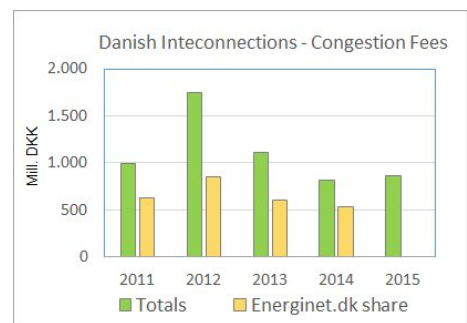


Fig. 7 - Congestion income and Energinet.dk share for Danish interconnections

<sup>2</sup> Source: Download from Energinet.dk, Market Data

It is possible to extract the total congestion income per link from the market data (fig. 8). The links are:

- DKW-N: Skagerrak, DKW to Norway
- DKW-S: Konti-Skan, DKW to Sweden
- DKW-DE: HVAC, DKW to Germany
- DKE-S: Øresund, DKE to Sweden
- DKE-DE: Kontek, DKE to Germany
- DKE-DKW: Internal Danish HVDC link

There are two main reasons for the variations: variations in transferred volumes and price variations in the spot markets.

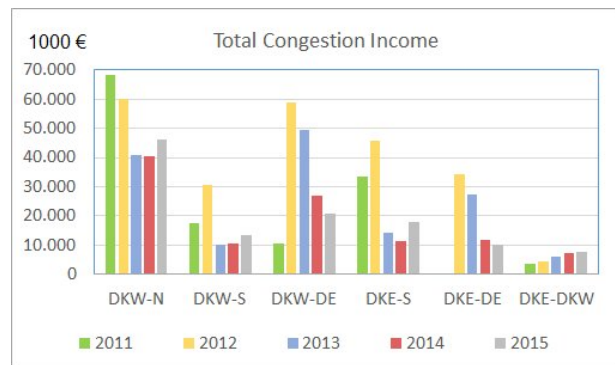


Fig. 8 - Congestion income per link 2011 to 2015

The year 2015 was rather wet in Norway. The high inflow of water gave more transferred electricity on the Skagerrak link, DKW-N (fig. 9).

The installation of new wind power in Schleswig-Holstein has caused a decreasing trend on DKW-DE.

The internal Danish HVDC link, the Great Belt link, shows a steady increase of energy transfer from 2011 to 2015.

The congestion income per transferred MWh indicates for each border the magnitude of the spot price differences.

In 2012 the main flow directions for DKW was from Norway and Sweden to DKE and Germany. For DKE there was a flow from Sweden and DKW to Germany. The “distances” in €/MWh from Norway and Sweden to Germany were from 16 to 21 €/MWh, depending on the route.

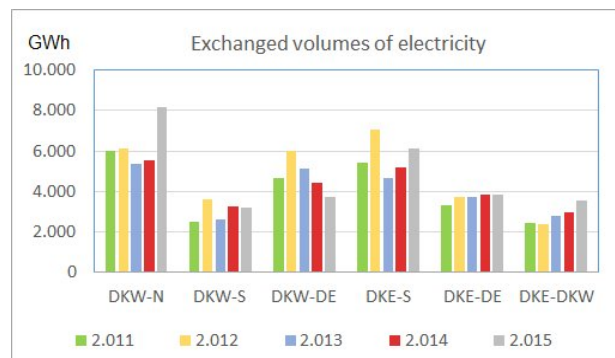


Fig. 9 - Transfer per border 2011 to 2015

The flow directions were more mixed in 2015. DKW had a considerable import from Norway, but export to both Sweden, DKE and Germany. DKE imported from Sweden and DKW, but exported less than half the import to Germany. The “distances” were about 11 €/MWh from Norway to Germany via DKW and less than six €/MWh from Sweden to Germany via DKE.

In spite of the reduced “distances”, there is still a large gap between low and high wholesale prices in Europe (table 2).

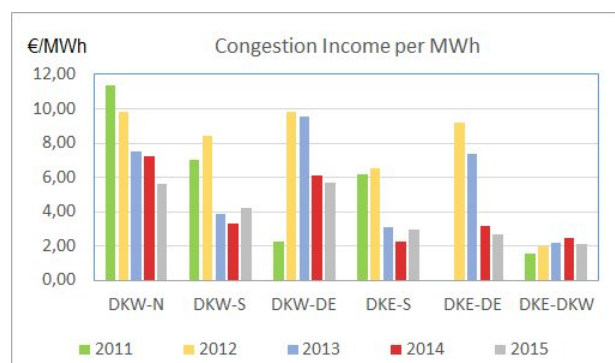


Fig. 10 - Exchanges are driven by price differences

It will take both grid reinforcements and improvements of the market systems to reduce these price differences. It is an open question how far it will be reasonable to go.

Average Wholesale Baseload Electricity Prices <sup>3</sup>	
Third quarter of 2015	€/MWh
Norway	11.90
Germany	32.80
Great Britain	58.10
Spain	56.40
Greece	53.80

*Table 4 - Wholesale price levels in Europe*

We do not know the magnitude of the bottleneck fees for other countries than Denmark. The main export nations in 2014 were France (67.6 TWh) and Germany (35.7 TWh). The main import countries are Italy (43.7 TWh) and UK/Ireland (23.6 TWh). Twelve exporting countries had a net export at 186 TWh<sup>4</sup>. This is not necessarily the total export, but it is a fair estimate. To move electricity from Norway/Sweden to either Great Britain or Italy, it is necessary to cross up to four borders between price zones. Assuming that the “distance” from Scandinavia to these two countries is 30 €/MWh, the average “distance” across one border is between five and ten €/MWh. Based on these assumptions the magnitude of the total European bottleneck fees could be one or two billion € per year.

The money will be needed for the necessary grid reinforcements in Europe. The project, eHighway2050<sup>5</sup> estimates the cost of new transmission facilities to be between 120 and 640 billion € depending on scenario and construction details, such as the choice between underground cables and overhead lines.

There has been a discussion in the past about grid owners’ temptation to consider potential revenues rather than operational limits when defining maximum exchange capacities. It should be emphasized that nothing indicates irregularities in the setting of capacity limits for Danish interconnections.

<sup>3</sup> Source: <https://ec.europa.eu/energy/en/statistics/market-analysis>

<sup>4</sup> Source: ENTSO-E: Electricity in Europe 2014

<sup>5</sup> [http://pfbach.dk/firma\\_pfb/pfb\\_ehighway2050\\_2016\\_01\\_07.pdf](http://pfbach.dk/firma_pfb/pfb_ehighway2050_2016_01_07.pdf)