Application to introduce implicit loss handling on the Skagerrak Interconnector

The enclosed document contains the rationale for the joint application of Energinet and Statnett to introduce implicit loss functionality on the Skagerrak interconnector. The document includes a description of the applied-for method and an assessment of the expected socio-economic consequences, including distribution effects, from introducing implicit loss handling on the Skagerrak Interconnector. Further, Appendix 1-3 respectively include further description of the principle, the socio-economic analysis and analysis of intraday arbitrage.

The implicit loss functionality will be implemented by the introduction of a fixed annual loss factor for the Skagerrak Interconnector. The loss factor will be adjusted annually based on historic median flow for all hours with flow for the Interconnector. The annual socio-economic gain from introducing implicit loss handling for the Skagerrak Interconnector is estimated at approximately EUR 0.9 million for Norway and EUR 2,3 million for Denmark.

The title and thus the scope of Annex I to Regulation 714/2009, “Guidelines on the management and allocation of available transfer capacity of interconnections between national systems”, support the Annex having a substantial legal significance of its own. For example, the Annex may provide a legal basis for introducing methodologies of cross-border significance on an interconnector.

As an EEA EFTA State, the Norwegian parliament has voted to incorporate the EU’s 3rd Energy Package, including Regulation 714/2009, into national legislation. However, the entry into force of that legislation is contingent on adoption by all EEA EFTA States, and adoption by Iceland is still lacking. Consequently, Regulation 1228/2003 of the EU’s 2nd Energy Package still applies for Norway. Fortunately, the Commission’s Decision 770/2006 has amended the Annex to Regulation 1228/2003, thus forming the basis for the subsequently adopted Annex I to Regulation 714/2009. Accordingly, the legal basis for the following bilateral procedures for the matter in question is stated in the following.

The Annex to Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003, as amended by Commission Decision No 770 of 9 November 2006, is similar to Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009. In particular, it is emphasised that paragraph 3.1 in the Annex to Regulation 1228/2003, is similar to the same paragraph 3.1 in the Annex I to Regulation 714/2009. Thus, that particular paragraph states in part that congestion management expected to affect physical flow in any 3rd country significantly shall be coordinated at both TSO and NRA level.

The relevant legal basis in Norway for the introduction of implicit loss factor on the Skagerrak Interconnector is the Norwegian Energy Act and in particular Statnett’s “Concession for interconnectors to other Nordic countries”. It follows from Section 5 in that concession that transmission losses should be taken into account in the energy-trade if loss functionality is available in relevant trading systems. Moreover, according to Section 7, all amendments to existing agreements and new agreements of significant importance which fall within the scope of regulation in this license shall be submitted to the Norwegian Water Resources and Energy Directorate for approval well in advance before they enter into force.

In addition, relevant provisions of Regulation (EC) No 1228/2003 including the Annex to the Regulation will apply. The Annex to Regulation 1228/2003 is aligned with Annex I to Regulation 714/2009 as a result of the Commission’s decision 770/2006.

The relevant legal basis in Denmark for the introduction on implicit loss factor for Skagerrak is solely Annex I of Regulation 714/2009, in the sense that directly applicable EU law in terms of Regulation 714/2009, and/or the Commission's regulations on network guidelines, the CACM Regulation etc., replace any national Danish provision on the actual subject of the matter, the introduction of methodologies etc. on a cross-border interconnector.

By the same token, the Danish Utility Regulator as the national regulating authority of Denmark has the authority to issue administrative decisions on the legal basis of directly applicable EU law. See Section 1, Subsection 2, no. 4, in the Act No. 690 of 8 June 2018 on the Danish Utility Regulator.

ENERGINET Statnett

Implicit loss handling on the Skagerrak Interconnector

Table of Contents

1. Rationale for the application

When current flows in an electrical network, some of the energy will be lost through heating of the electrical components, and the power volume that reaches end users will thus be less than the volume produced. On HVDC interconnectors between Norway and other countries, this loss will be between three and five per cent. However, the electrical loss, which constitutes a large socio-economic cost, is not included in the pricing in the power market. Without intervention from TSOs, agreed production and consumption (after market clearance) will therefore result in a balanced market, but without an operationally balanced system.

The operational imbalance caused by losses on the Skagerrak Interconnector is currently handled by the TSOs buying power to cover the transmission losses[1] so as to ensure that the system is in balance both market-wise and operationally. “Explicit loss handling”, which is used for the losses both in the AC grid and on HVDC interconnectors, is regarded, however, as an ineffective way of handling losses.

The TSOs’ purchases of losses affect the power price but are not linked to the transmission interconnector(s) where the losses actually occur. This means that the market participants are not provided the price signals necessary to take into account their influence on the electrical loss. Electrical losses thus represent a negative external effect that results in an unnecessary socio-economic loss. This can be directly observed in the fact that power is traded between bidding zones at times where the value of the power trade (the price difference) is less than the cost of transmission losses. By taking into account (internalising) electrical losses in the market price, a socio-economic gain can therefore be achieved.

In the AC grid, the electrical losses are partially internalised through the grid tariff in which a loss component ensures that the participants pay a tariff according to bidding zone and time of day that reflects electrical losses. On HVDC interconnectors, the losses can be internalised through “implicit loss handling”. Statnett and Energinet have therefore worked on implementing the solution on their shared HVDC interconnector, Skagerrak[2].

2. Method for implicit loss handling

With implicit loss handling, the electrical losses are represented in the market through a new limitation in the market coupling. This ensures that exported volume is reduced by a loss factor between exporting and importing bidding zones. The market prices will thus be affected by the new restriction so that:

With congestion: ***Export price < (1 - Loss factor) * Import price***

Without congestion: ***Export price ≤ (1 – Loss factor) * Import price***

This change will ensure that power is not traded on an interconnector unless the value of the trade is greater than the loss cost.

The market algorithm already has a function for taking losses into account. Implementation of implicit losses on the Skagerrak Interconnector will in practice mean that the current loss factor on the Skagerrak Interconnector will change from nil to a positive loss factor.

3. Method for calculating loss factor for the Skagerrak Interconnector

The Skagerrak Interconnector consists of four parallel HVDC cables in which the actual physical loss increases exponentially with the quantity transferred. The loss is unique for each cable, but is

[1] This does not apply to “NorNed” or “Baltic cable” where implicit loss handling has been implemented.

[2] Where, Statnett already has it implemented on NorNed, interconnector between Norway and Netherlands today.

substantially greater for the two oldest cables. Both total quantity transferred and operating policy (how the load is distributed on the four cables) will therefore affect the physical losses for the Skagerrak Interconnector.

However, the market algorithm does not accept non-linear losses, and the physical losses must be represented in the market algorithm by a linear loss factor. This is estimated on the basis of the following linear description of loss:

Loss = No-load loss + (Loss factor * |Flow|)

The so-called “no-load loss” is the loss arising without a flow on the interconnector. The reason for this is that the cables are “energised” even when there is no flow on them. However, the no-load loss is very small, and we will therefore implicitly include this element in the loss factor estimate by setting this at nil. The relationship between the linear description of losses and the actual losses is thus illustrated in Figure 1.

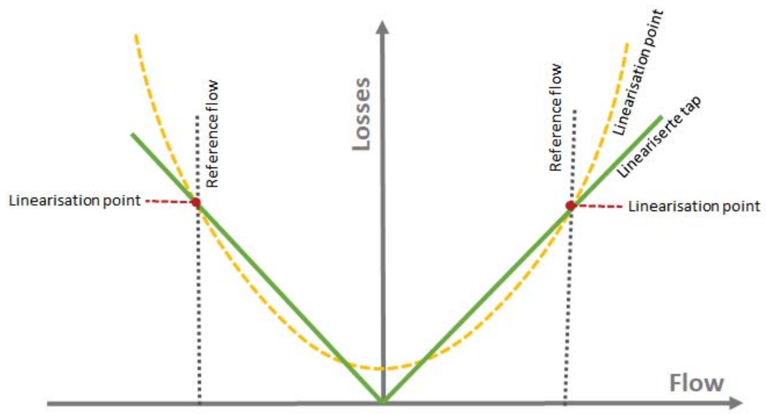


Figure 1 Relationship between actual and linearised losses

Losses is a function of flow, and thus the loss factor is also an input in the market clearance where the flow is determined. However, due to the linear nature of the applied loss factor, a reference flow for estimating the loss factor must be determined before we know the correct flow. An obvious question is therefore whether the loss factor should vary through the year by the hour, day, week or season. In this relation, we have conducted an analysis (See Appendix 1) which shows that such periodisation will only affect calculation of the loss factor to a very small extent. We will therefore use a fixed “annual” loss factor with annual adjustment. Market participants and the Danish and Norwegian NRA will be informed prior adjustment of loss factor. However, we will also consider the need for adjustment during the year if the circumstances so indicate. As a reference flow, we will use the annual median flow for all hours with positive flow. The choice is based on an analysis in which we assessed two different averages and two different median values. The analysis did not yield significant differences in resulting loss factor (See Appendix 1).

For the loss factor estimate itself, we have two methods available. One is a (fundamental) “Bottom Up“ model, and the alternative is a (statistical) “Top Down“ model. In the “Bottom Up“ model, the physical losses are calculated for a given reference flow based on a complete description of the components in the Skagerrak Interconnector, including an updated operating policy. In the “Top Down“ model, on the other hand, a statistical analysis of time series for measurement data (flow and losses) is used in the calculation. (Appendix 1 contains a detailed description of the two different models.)

The strength of the “Bottom Up” model is that it provides a precise estimate of losses for a given flow and a given operating policy. The disadvantage is that the result depends on a specific “Control setting" for the transmission installation (which in reality) may change over time. The advantage and disadvantage of the "Top Down" model are exactly the opposite. The model is less precise for a given flow and operating policy, but on the other hand it is independent of "Control Settings".

In our estimates of loss factor for the Skagerrak Interconnector, we have decided to use the "Bottom Up" model for the starting value, whereas we will later use the "Top Down" model in connection with adjustments. Based on the above description, we have (based on data from 2017) a reference flow for the Skagerrak Interconnector of 946 MW and a loss factor of 2.5 per cent. However, this calculation will be updated before implementation on the Skagerrak Interconnector and will then be based on the method described above.

4. Socio-economic consequences of implicit loss handling on the Skagerrak Interconnector

In the autumn of 2017, the Nordic TSOs completed an analysis of implicit loss handling for the HVDC interconnectors in the Nordic countries (See Appendix 2). The Skagerrak Interconnector was one of the interconnectors that was analysed at that time. A loss factor of 3.8 per cent was used, which represents the loss at full flow on the interconnector. The results which are further accounted for in this section are entirely based on the Nordic analysis report and thus based on a loss factor of 3.8 per cent. This is greater than what the method described in the preceding section recommends, which is exclusively because of the choice of reference flow.

While the actual net losses are non-linear, we have to formulate losses in the market algorithm as a linear function of flow. The losses will therefore never be represented entirely correctly in the market. However, because the TSO analysis is based in its entirety on a linear description of losses, it is impossible to determine the effect of this inaccuracy. However, the method for determining a loss factor presented in the preceding section is aimed at reducing the discrepancy between implicit and actual losses and will therefore contribute to reducing any loss of effect by using a linear loss description in the market algorithm.

Analysis method

The socio-economic analysis of the Skagerrak Interconnector was conducted in two steps.

1. The market effects from implementing implicit losses (3.8 per cent on the Skagerrak Interconnector) were studied through simulations over 16 months with actual market bids (February 2014 – May 2015). The simulations were conducted in the market algorithm "Euphemia", and the results have been normalised to apply to each individual year. (See Appendix 2 for a more detailed description of the analyses.)
2. Because the market does not see the physical effects on electrical losses of transmission, a statistical analysis was carried out of loss effect in the AC grid and the HVDC interconnectors. The physical losses were then priced with prices from the market simulations. (See Appendix 2 for a more detailed description.)

The total socio-economic effect from implementing implicit losses on the Skagerrak Interconnector will thus be given by:

$$\mathbf{\Delta W = \Delta Market\ gain - \Delta Loss\ costs}$$

In which:

ΔMarket gain = ΔPS + ΔCS + ΔCI **(Stage 1)**

ΔLoss costs = ΔAC + ΔDC **(Stage 2)**

Δ = Change
W = Socio-economic surplus
PS = Producer surplus

CS = Consumer surplus
CI = Congestion income
AC = Loss costs in the AC grid
DC = Loss costs in the HVDC grid

Because electrical losses are not part of the market algorithm, a loss factor in the market simulations will only increase the cost of transmission. We must therefore expect that the first stage in the analysis will result in a negative contribution to the socio-economic surplus whereas the gain in the form of reduced losses will arise in the second stage. Theoretically, the sum of Stages One and Two should result in a positive socio-economic result (correction of a negative external effect).

When implicit loss handling is introduced on the Skagerrak Interconnector, transmission between NO2 and DK1 will become more expensive. The power will thus find other routes in the grid, for example via Sweden. Implicit loss handling on the Skagerrak Interconnector will thus reduce the losses on the Skagerrak Interconnector but will result in increased losses in the AC grid and the other HVDC interconnectors in the area. However, the analyses take into account all such effects and price them according to the relevant bidding zone prices. The resulting change in loss costs we find in the analyses is thus the net effect on loss costs. A positive change in loss costs (lower loss costs) thus means that the positive effect on the Skagerrak Interconnector is greater than the negative effects in the AC grid and the other HVDC interconnectors.

Market effects

The market effects from implementing implicit losses on the Skagerrak Interconnector are shown in Figure 2 with results for the Nordic countries, Norway and Denmark in million EUR. As expected, we see that the market gain is negative for Norway, Denmark and the Nordic countries as a whole. However, in Norway a small, but positive, consumer surplus and a negative producer surplus arise. This is the reverse for Denmark. Nevertheless, we cannot conclude in general that Norwegian consumers will win and the producers will lose. There are two circumstances that will influence this.

Firstly, the distribution is a result of the price effects in question during the analysis period, where typically higher transport costs will benefit consumers on the export side and producers on the import side of a bottleneck. Distribution effects between consumers and producers will thus vary between years, where the predominant flow direction to a large extent will determine the distribution. In years with a power surplus in Norway, which we expect will be the norm, implicit loss handling will result in a somewhat lower Norwegian power price and will thus benefit Norwegian consumers. The opposite will be the case in years with power deficits.

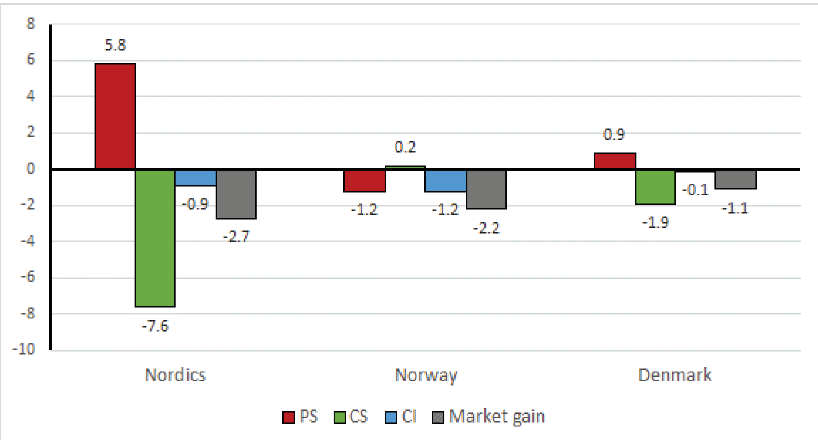


Figure 2 Annual market effect of implementing implicit losses on the Skagerrak Interconnector, in million EUR

Secondly, we must also take into account tariff effects. When the TSOs introduce implicit loss handling, they will no longer pay for the losses through market operations (purchases of losses). This will benefit tariff customers through lower tariffs for consumption. This will in turn compensate for any reductions in the consumer surplus to a greater extent than for the producer surplus. However, the latter element has not been analysed, and it is therefore not possible to determine the strength of the tariff effect.

Effects on flow and Grid losses

The loss costs consist of changes in losses in the AC grid and on HVDC interconnectors. When implicit loss handling is introduced on an HVDC interconnector, as mentioned earlier, the cost for transmission in the AC grid and on HVDC interconnectors will become relatively less expensive. We can therefore expect higher transmission losses and loss costs in the AC grid and on HVDC interconnectors. On the other hand, the total losses on the HVDC interconnectors, including Skagerrak, can be expected to be reduced. The total changes in loss costs in the AC grid and on the HVDC interconnectors from our analyses are shown in Figure 3. The total loss costs on the Norwegian and Danish HVDC interconnectors are substantially reduced, while we only have a slight increase in the loss costs in the AC grids.

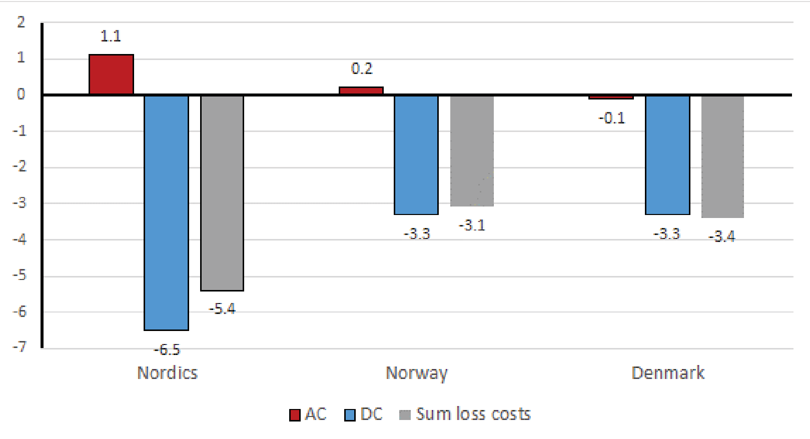


Figure 3 Annual change in loss costs in the AC and HVDC grid with implicit handling of losses on the Skagerrak Interconnector, million EUR

Total socio-economic result - Summary

As previously mentioned, the total socio-economic result consists of two parts, changes in market gain and changes in loss costs.

As expected, the market gain is negative, while the loss costs decrease. We thus find the total socio-economic gain from introducing implicit grid losses on the Skagerrak Interconnector by adding the results in Figure 2 and Figure 3. This is shown in Figure 4 where we see that the estimate yields an annual gain of EUR 0.9 million for Norway and EUR 2.9 million for Denmark from introducing implicit loss handling on the Skagerrak Interconnector. The reason for the gain being greatest for Denmark is that AC losses and trading income are more strongly affected in a negative direction in Norway than in Denmark during the period analysed.

Implicit loss handling on Skagerrak thus results in an expected socio-economic gain for Norway without significant negative issues for operational reliability in the AC grid.

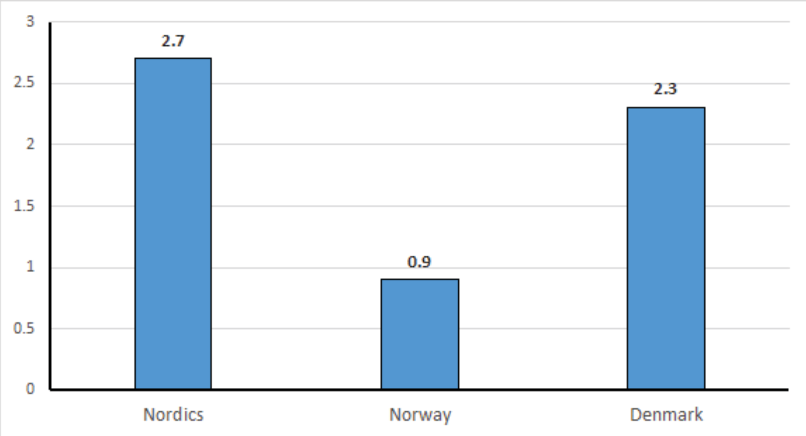


Figure 4 Annual socio-economic gain from implicit loss handling on Skagerrak, million EUR

Operating conditions

The loss costs in the AC grid are related to effects on both price and physical flow, and it is therefore necessary to ask whether the physical changes to flow in the AC grid might result in any operational issues. The most appropriate area to examine more closely as regards the AC grid is the interconnector between NO1 and SE3. The results for changes in flow on NO1-SE3 are shown in Figure 5. The first thing we notice is that the total flow on the interconnector increases by approximately 5 per cent. This is not in itself reason for operational concern as the interconnector usually has available capacity at times throughout the year.

However, a more appropriate measurement for the operating situation is whether increased flow results in a more difficult operating situation during high loads. We have sought to show this by looking at how large an increase we have in the number of hours with high flow, represented by the percentage increase in the number of hours with flow exceeding 90 per cent and 99 per cent of specified market capacity. What we see from the figure is that the annual number of hours with flow close to full capacity utilisation (over 99 per cent of market capacity) increases by 24 per cent. However, this is something we will also see as a variation during various years, for example because of the hydrological situation. Therefore, this is not in itself to be considered particularly problematic beyond what we see with respect to usual variation.

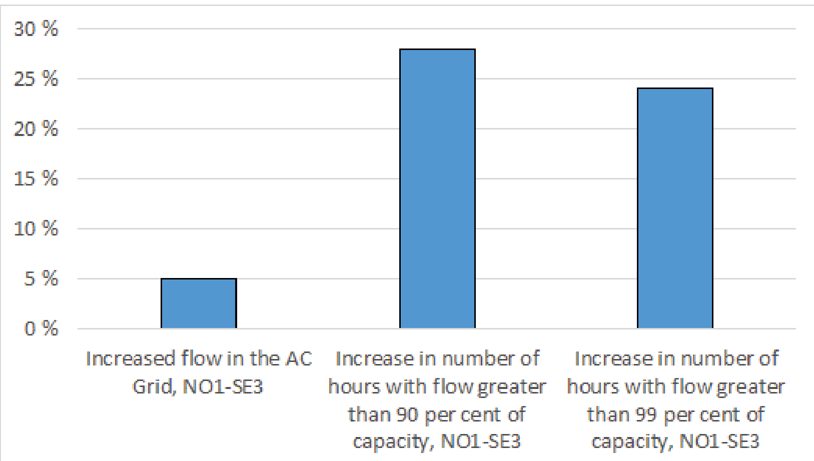


Figure 5 Changes in Flow in the AC grid as a result of implicit handling of losses on the Skagerrak Interconnector

Another question is whether during periods of full capacity utilisation on NO1-SE3 we might have an increased potential for physical overloads because of implicit handling of losses on Skagerrak. When there is full capacity utilisation on NO1-SE3, there will also be a large price difference between the two bidding zones. In such situations, there will also usually be a large price difference between NO2 and DK1, and implicit loss handling will thus hardly affect the flow on either the Skagerrak Interconnector or on the interconnector between NO1 and SE3. On the other hand, there will not be any flow on the Skagerrak Interconnector before a bottleneck has arisen at Konti-Skan and the Great-Belt Interconnector. However, the latter only applies until implicit loss handling is introduced on the two referenced HVDC interconnectors.

Seen as a whole, there is limited reasoning that implicit handling of losses on the Skagerrak Interconnector will result in an unacceptable reduction in operational reliability.

Change of flow on Danish Interconnectors

As described there is a positive welfare economic effect of implementing implicit grid loss on the Skagerrak interconnector. The effect in increased AC loss cost is outweighed by the decrease in HVDC-loss cost. The loss cost are an aggregate of the change in physical flow and the change in electricity price. Thereby the result could in theory be due to a high change in physical flow and a minor change in the electricity price difference. The results of the simulation of physical flow can be seen in the below Table 1.Table 1 Simulated change in flow on Danish Interconnectors in average over the period of the Common Nordic Analysis (February 2014- May 2015)

Interconnector	DK1-NO2	DK1-SE3	DK2-SE4	DK2-DE	DK1-DE	DK1-DK2
Change in flow	-19.6 %	9.3 %	7.2 %	0.1 %	-2.3 %	-4.8 %[3]

Table 1 Simulated change in flow on Danish Interconnectors in average over the period of the Common Nordic Analysis (February 2014- May 2015)

The above results indicate an increase in flow over the period of the Nordic Common Analysis, on the Swedish Interconnections, Konti-Skan and Øresund, whilst the flow on Kontek is unchanged. The connections West-Denmark to Germany and Great-Belt also have a decrease in flow of respectively 2,3 pct. and 4,8 pct.

The congestions that currently are visible on the Danish-Swedish interconnector, in part due to the restrictions of the West-Coast Corridor are regarded in the analysis, as the results are based on historical values, where the congestion due to the West-Coast Corridor also where apparent.

Electricity Price Convergence

The main reason for implementing implicit grid loss on the Skagerrak interconnector is the increase of effectivity of use of interconnector capacity and thus there should be no flow on an interconnector if the price-difference is smaller than the costs of transporting the Energy. Thereby, only in the rare

[3] Regrettably, the value for the Great-Belt interconnection is not included in the Nordic Common Analysis, however, is accessible in the underlying data.

cases when the price is zero in both bidding zones, will there be full price convergence on the interconnector with implicit grid loss implemented.

Nevertheless, the price convergence in itself is not a standard for efficiency and should thus not be of concern with regards to the decision of implementing implicit grid loss. Further, as an example, if Skagerrak is out of service, there is also the possibility that prices are convergent in the bidding zones NO2 and DK1 through flow from neighbouring bidding zones. However, this does not imply that the Skagerrak interconnector was used efficiently either.

The main aspect here should be the social economic surplus. Thus, Energinet and Statnett will in time communicate to market participants other measures to reflect the efficiency of markets and interconnector usage.

5. The Intraday market

The objective is to implement implicit loss handling in both the Spot and the Intraday markets. However, the functionality for handling implicit losses in the Intraday market has not yet been implemented in the Cross- Border Intraday Market (XBID), and there is reason to believe that this will come somewhat later than in the Spot market. We consider this a temporary problem as we expect that this interim period will only last a short time. XBID currently is implementing a proto-type, which will thereafter be translated into the actual solution. It is expected that the solution for implicit loss handling in XBID will be available in 2020.

It is conceivable that during this interim period the expected efficiency gain can be reduced through arbitrage for the Intraday market. However, because the losses in the Intraday market will be the same as in the Spot market, it will be impossible to come out worse than with the current handling of losses. In the worst case, there will be full arbitrage and thus no effect from implicit loss handling in the Spot market until the solution is activated in XBID. However, this is unlikely as the Intraday market is used mainly for handling balancing by the participants responsible for balancing. It is therefore expected that any arbitrage between the Spot and Intraday markets in the interim period will be moderate in any event, which is also supported by experiences from introducing implicit loss handling on the interconnector between Norway and the Netherlands (see detailed discussion in Appendix 3).

Furthermore, article 23 (3b) of CACM regarding “methodologies for operational security limits, contingencies and allocation constraints” states that “constraints intended to increase the economic surplus for single day-ahead or intraday coupling”, thereby an allocation constraint may be implemented if it increases the economic surplus of either single day-ahead or intraday coupling. In the interim period of implementing implicit grid loss on the Skagerrak interconnector the studies made by Statnett and Energinet and the rest of the Nordic TSOs indicate that the implementation of implicit grid loss on the Skagerrak interconnector will increase the economic surplus for the day-ahead market. Therefore, Energinet and Statnett conclude that the implementation of implicit grid loss in the day-ahead market prior to the intraday market is in line with the CACM regulation. And as stated above it should be noted that this is solely for an interim period until the intraday market solution for implicit grid loss is developed.

6. Balancing market

The current rules of the balancing market for upward and downward regulation encompass that upregulating bids are at a minimum the day-ahead market price, and for downward regulation the bid is at a maximum the day-ahead market price. Thus, in an example where there is export to Norway from Denmark, with a price of 400 DKK/MWh, the price in Norway would be 416 DKK/MWh (with implicit grid loss factor), assuming that the prices are equal without implicit grid loss. Thus the Danish upregulating bids are at 400 DKK/MWh, which would be first priority over the Norwegian bids at 416 DKK/MWh and for downward regulation the bids of 416 DKK/MWh in Norway would be prioritised over the price of Danish bids at 400 DKK/MWh. The point being that the current setup would lead to a more systematic difference between the choices of bids in the two bidding-zones. Yet, the supply curves are more likely not horizontal, which indicates that the effect is not expected to be significant.

Furthermore, the flow direction between Norway and Denmark changes throughout the year, therefore, it can be assumed that market participants are both affected, as the above described situation also occurs in opposite direction, if there is import to Denmark.

The Nordic TSOs are currently implementing a new balancing market, under Electricity Balancing Guideline (EB GL). The principal for the rules on the balancing market and methodology cannot solely be decided by Energinet and Statnett, as these are all TSOs decisions and all NRA approvals, cf. EB GL. For example, in the MARI implementation work, three options are being considered:

1. Losses are not considered
2. Losses are considered by looking at the marginal flow
3. Losses are considered taking into account the total flow from previous time frames.

Thus, the ongoing work in MARI include thorough analysis of the possibilities to implement implicit grid loss in the balancing market. The outcome of these, to ensure the best for the Danish and Norwegian Stakeholders can be affected by Energinet and Statnett, however it cannot be guaranteed. The development will also decide if there will be implicit grid loss in the balancing market.

7. Future development and Nordic Cooperation

Energinet and Statnett have the ambition to implement implicit grid loss on all their HVDC interconnectors in the future. Therefore, Energinet and Statnett aim to engage in close cooperation with the Nordic and adjacent TSOs to come to an agreement on possible future implementation on other HVDC interconnectors, to secure the social economic benefits, as presented in the Common Nordic Analyses on effects of implementing grid losses in the Nordic CCR.

8. Effect on other regions

At the time when Energinet and Statnett respectively decide to implement implicit grid loss with a neighbouring TSO, analysis of the potential consequences of flows due to implementing implicit grid loss on further interconnectors will be done. For the time being there are various reports on implicit grid-losses, which assess the effect on flow in the NWE area.

During the public consultation, Energinet received a comment concerning that trading energy between Norway and Denmark is likely to become more expensive than trading energy from Portugal to Denmark. However, such trades carry large AC loss-cost to be paid by TSOs via tariffs and shared in the ICT process by the TSOs. Implicit grid loss rather aims to correctly reflect the loss cost near or at its origins.

9. Relationship to European legislation

The objective with CACM is to arrange for an efficient European power market and efficient trading in power across bidding zone boundaries. Implicit loss handling will result in making trade over HVDC interconnectors more efficient and thereby contributing to the overall goal with CACM.

CACM will lay the groundwork for efficient power trading, and there are no circumstances in the arrangement, or in relevant methods developed under the arrangement, that create obstacles to implementing implicit loss handling on the Skagerrak Interconnector.

There are many developments in the electricity markets presently as the implementation of the CACM, EB GL and FCA guidelines proceeds. These have been forwarded as an argument for postponing implementing implicit grid losses as it is not one of the requirements of the regulations. However, the regulations aim to increase the efficiency of the electricity markets, which is also the case with implicit grid loss implementation. Since the beginning of the electricity markets, they have been in rapid development, and will be in future, therefore there is never an optimal timing of implementing a new methodology such as implicit grid loss. The method has been discussed and analysed several times for many years, which all indicate that there is a social-economic welfare gain to be achieved

The all Nordic TSO “Analyses on effects of implementing grid losses in the Nordic CCR” of 30 April 2018, showing a welfare benefit for the Nordic countries thereof, is in Energinets and Statnetts evaluation deemed sufficient meet the condition within Article 6(1)(c) of CCM for CCR Nordic, in demonstrating an EU-wide welfare economic benefit.

10.Implementation

Some work still remains before implicit handling of grid losses on the Skagerrak Interconnector can be implemented. The tasks include the following, with the current plan of implementation:

1.	Identify changes necessary in existing agreements	May (2019)
2.	Identify the need for changes in IT/Communications infrastructure	April-May (2019)
3.	Implement changes in agreements and IT/Communications infrastructure	May-November (2019)
4.	Functionality testing	November (2019)
5.	“Go Live”	January (2020)

11. Appendixes

Appendix 1: Principles for calculating a loss factor for the Skagerrak connection

Appendix 2: Analyses on the effects of implementing implicit grid losses in the Nordic CCR

Appendix 3: Arbitrage between the day-ahead and intraday market

Principles for calculating a loss factor for the Skagerrak connection

Background

The Skagerrak interconnector contains four DC cables labelled SK1 - SK4. The newest cables, SK3 and SK4, have higher transmission capacity and significantly lower energy-losses than SK1 and SK2. Due to lower losses, the operators are running most of the power-flow on the Skagerrak connection towards the two newest cables, in order to improve effectiveness of the Skagerrak operation.

When operated in unity, the four cables are able to transmit more power than the sum of each cable on its own. Thus, the max physical flow on the Skagerrak interconnector is 1632 MW, which is determined by the receiving end flow, while the sum of each cable operated independently is 1350 MW. Further, by an arrangement between Statnett and Energinet, 100 MW are currently reserved for auxiliary services, and therefore the max flow allowed for the day ahead and intraday market is 1532 MW.

The relation of max flow and losses on the respective Skagerrak cables are indicated in table 1 based on a bottom-up model (Appendix 2). The table visualises the losses of each individual HVDC pole, from SK1 through to SK4, when operated independently and where the remaining three HVDC poles, respectively, are set to zero MW. The “sums at” columns further indicate the loss factor at max flow allowed after determining the receiving end capacity (1632 MW) and additionally when the 100MW for auxiliary services are removed (1532 MW). As the below table indicates, there are different sizes of losses depending on how Skagerrak is operated.

	SK1	SK2	SK3	SK4	Sum at	Sum at
Max flow	227 MW	227MW	330 MW	481 MW	1532 MW	1632 MW
Loss at max flow	6.4%	6.4%	2.8%	2.3%	3,1%	3.5%

Table 1 Losses on the Skagerrak interconnector for the individual cables run in isolation, and for the total interconnection in sum for different load levels. Take note that the max load for each cable, when run in isolation, is smaller than the max load when run as a system. Results from the bottom-up model.

Figure 1 is a diagram showing the configuration of the four Skagerrak cables. All numbers in the figure are derived from a case with 1532 MW of flow from NO2-DK1.

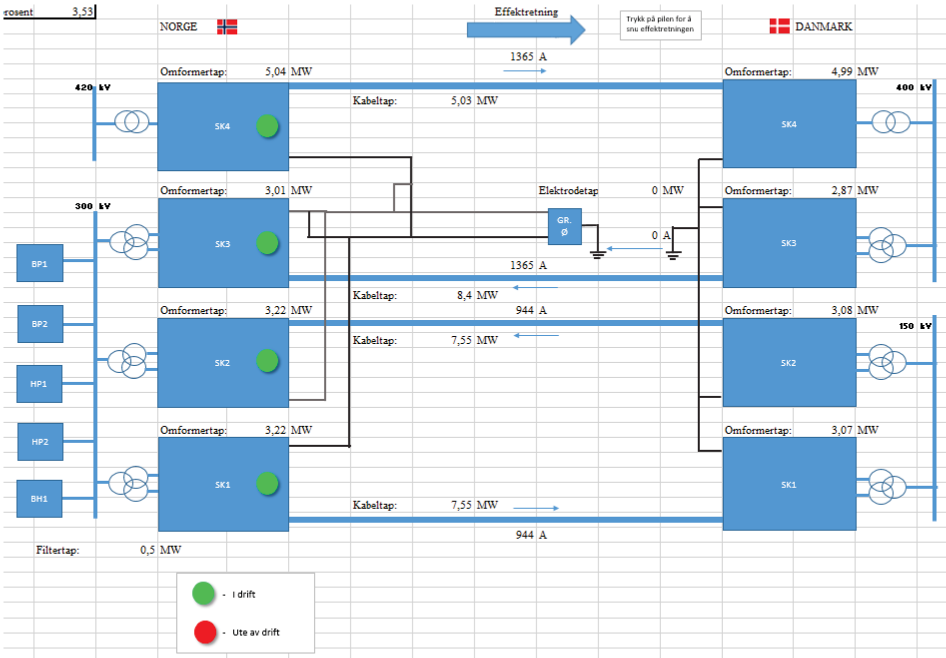


Figure 1 Configuration of the Skagerrak connections

As there are differences in the loss factor based on what assumptions are applied in the calculation thereof, Statnett and Energinet have agreed to the below methods and calculations.

Calculating a linearized loss factor for the Skagerrak connection

Losses on HVDC borders consisting of multiple poles, such as Skagerrak, shall be aggregated for each border. On these multi-pole borders the losses depend on the configuration of the DC circuit as well as the load sharing between the poles. This methodology proposes on a *proportional* loading of each pole of the HVDC border (e.g. 50% total multi-pole loading corresponds to 50% on each of the individual poles).

When the market clearing model (Euphemia) considers implicit losses, only a proportional factor of the flow can be included. This means that the square function has to be linearized near a typical operating point. In theory the factor could be updated for every hour based on a flow forecast. In reality this is not considered as a realistic approach worth the effort as it may require changes at the NEMO, missing transparency for the market participants and additional processes at the TSO while not necessarily providing any significant socioeconomic benefit. Thus, the below methodology describes, how the TSOs intend to calculate and apply the loss factor on the Skagerrak interconnector.

Function of the loss factor

The real losses on the DC cables are non-linear in relation to the flow. However, due to limitations in the market algorithm, the losses have to be represented by a linear relation (loss factor) to the flow in the following form:

Loss factor = "Real losses at reference flow (MW)" / "Reference flow (MW)"

Yet, as there are various ways of calculating the real loss factor, and also what reference flow/ linearization point to be used, the following chapters will clarify Energinet and Statnett's argumentation and decision.

No-load losses

One of the factors that affect the loss factor calculation is the decision on integrating the converter losses at zero flow. With the converter losses at zero flow the linearization of the loss factor has the base of zero flow, where there already is an amount of energy that is lost just due to having the interconnectors operational. Ignoring the no-load loss at the start of flow from the interconnector, the calculation will have the minimum flow as a basis. This will result in a difference in the linearization, or rather the approximation, towards the reference flow.

The choice for Energinet and Statnett is to include the no-load losses in the linearization. It is reasoned that including the no-load losses in the linearization will lead to a result, where the error in estimation based on the reference flow will be minimized. Especially, due to the fact that there will not be many hours with partial load, thus, there will be a better approximation towards the real losses.

Approach for calculating the real losses

The real losses on the Skagerrak interconnector might be calculated either by a "top down", or a "bottom up" approach.

"Top down" approach

The "top down" calculation (see appendix 1), is based on applying a statistical estimator on real time measurements and gives a statistical estimation that resembles the actual flow. This method provides us with a statistical relation between flow and losses, depictured in figure 2.

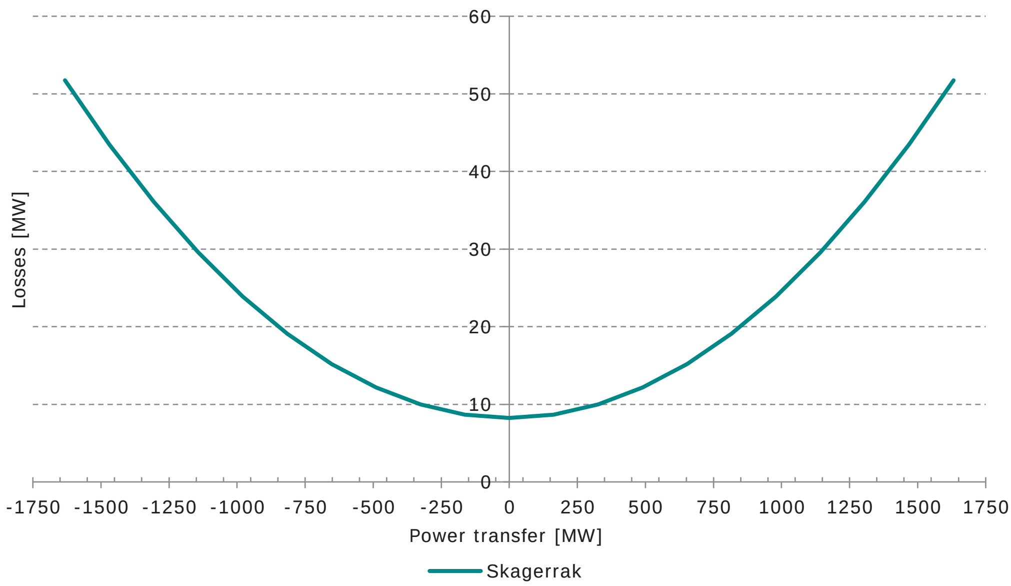


Figure 2 Estimated relation between flow and losses

"Bottom up"

The "bottom up" approach is implemented in a model/tool (see Appendix 2, the user interface is depicted in figure 1). In this tool, all the components of the Skagerrak interconnector is modelled in detail[1] and the losses are calculated for different flows based on the real operation of the four cables forming the interconnector. The tool is based on the configuration depicted in figure 1, and allows for disconnecting one or several of the cables, and an endogenous distribution of the flow on the connected cables.

[1] Take note that the bottom up model requires the input of all the components, and is based on the detailed information available on these, which are results gathered under certain conditions, that might not necessarily apply in all situations.

Comparison of approaches

The bottom up model is more precise, as it represents a detailed calculation on a "component level", and it provides some optionality in terms of the possibility of shifting the loss factor if any of the different cables might be in an outage state. On the down side, this model will not capture different control settings applied within the year.

The statistical model will capture the fact that such different settings in the control systems (for example the distribution of flow on the four different cables) will vary within a year and influence the real losses. On the down side, the statistical model will have to be updated with a yearly frequency.

Both approaches estimate a linearized loss factor of ca. 3.2% at 1632 MW. In the "bottom up" tool, the 1632 MW of total flow is associated with operating the interconnector with a flow of 208 MW on each of SK1 and SK2, 500 MW on SK3 and finally 715 MW on SK4 according to the parameters set in the model.

Determine the reference flow

Independent of the approach, a linearized loss factor is required for application in the day ahead and intraday market. Due to the non-linearity of the real losses, this will cause an underestimation of the losses when the real flow is above the reference flow/linearization point, and an overestimation whenever the real flow is below the estimation point. Thus, in principle, the TSOs should aim at a reference flow for the linearized loss factor calculation that will minimize the linearization error.

The below describes the arguments the TSOs encountered with regards to setting a reference flow.

In theory, it could be important to distinguish between different hours of the day or between different seasons. However, the difference in resulting loss factors by such differentiation seems small (as calculated by the "bottom up model"), and would probably create more uncertainty than gain. The evidence for this is depicted in table 2.

	2013	*2014*	*2015*	*2016*	*2017*
Yearly	2.2%	2.2%	2.5%	2.5%	2.4%
Hours 08-16	2.2%	2.2%	2.5%	2.6%	2.4%
Hours 17-07	2.2%	2.2%	2.5%	2.5%	2.4%
Month 04-09	2.2%	2.2%	2.5%	2.5%	2.4%
Month 10-03	2.2%	2.2%	2.5%	2.6%	2.4%

Table 2 Calculated loss factors based on different time periods, "bottom up" model

The first row indicates the loss factor calculated based on a yearly average for each of the the years 2013 - 2017, while the following rows present similar calculations for different time periods within each year. The difference between the years is not large, and the difference between time periods is even smaller. Based on these calculations, there is little reason to apply different loss factors for different time periods within a year.

Another relevant set of questions is how to calculate the yearly average. The options being:

a) Yearly average based on all hours
b) Yearly average based on all hours with a non-zero flow
c) Yearly median for all hours
d) Yearly median for all hours with a non-zero flow.

Calculated results for these options are presented in table 3.

	2013	2014	2015	2016	2017
Yearly Average	2.2%	2.2%	2.5%	2.5%	2.4%
Yearly Average – non-zero flow	2.2%	2.3%	2.5%	2.6%	2.5%
Yearly Median	2.3%	2.3%	2.5%	2.7%	2.5%
Yearly Median – non-zero flow	2.3%	2.4%	2.6%	2.8%	2.5%

Table 3 Calculated loss factors based on different statistical selections, "Bottom up" model

The results in the above table indicate that the TSOs find the results quite consistent without significant deviations between the different statistical selection criteria. However, the calculation based on yearly median values using only hours with a flow different from zero, are producing slightly higher loss factors than the rest. It might be argued that this would be a better selection criteria because the error produced in high flow situations are larger due to the convexity of the real losses. Although, it does not seem very pronounced, “Yearly Median – non-zero flow” is the preferred method for calculating the reference flow for Energinet and Statnett.

Loss factor at reference flow

The below table 4 presents the loss factor that is calculated based on the respective approach at the reference flow of 946 MW, which was calculated with aforementioned assumption (yearly median, only non-zero flow) .

Reference flow (year)	Top Down	Bottom Up
2015	2,5 %	2,6 %
2016	2,6 %	2,7 %
2017	2,4 %	2,5 %

Table 4 Calculated loss factors based on the specified approaches and the reference flow at the given year.

As was the case before, the two approaches lead to a similar loss factor given the reference flow of the different years.

In conclusion as the "bottom up” approach provides the loss factor with the parameter settings, the data should be fitted with the top down approach, in order to approximate the real loss best possible.

For the future this will also provide the possibility to update the loss factor as explained in the following.

Process for update of loss factors

In any case, it should be possible for the TSOs to adjust the loss factor on a yearly basis but also dependent on certain planned or unplanned events. For example, if modifications of the HVDC line configuration lead to a change of the loss factor by more than e.g. 20 % (for instance due to a cable failure or adding a new pole) and the situation is expected to persist for more than one month the TSOs should be able to request NEMOs to update the factors with a one week notice after notifying the NEMOs and NRAs.

Further, the allocation of reserves on an HVDC border could affect the capacity made available to the market. This may also lead to an updated calculation of the loss factors. The update shall follow the principles in this methodology.

Loss factor on the NorNed interconnector

Implicit losses were implemented on the NorNed interconnector on November 18 2015. The methodology for calculating a loss factor was similar to the above proposals for the Skagerrak interconnector. The average losses on the NorNed interconnector is estimated by the quadratic equation:

(1) $Y_x = 0.000043 * x^2 + 0.00618 * x + 1.4971$

The marginal loss is then provided by the equation:

(2) $Y_x = 0.000086 * x + 0.00618$

The reference flow level was set at the lower end of the midrange flow (300-400 MW) at 300 MW, providing a linearized loss factor at 3.2% that is implemented in the market algorithm. For 350 MW, the loss factor would have been 3.6%, and at 4.1 % at 400 MW.

In addition to the marginal loss, the fixed losses for energizing the interconnector (not a part of the marginal loss factor) is proposed to be procured separately.

From the discussion with the Dutch regulator it is clear that their biggest concern regarding the loss factor calculation is related to the choice of reference flow. From their perspective, it should not be based on the maximum flow, as it in most cases would lead to an underestimation of the losses. Thus, the TSOs of the NordNed cable chose an arithmetic median, as the reference flow. With regards to the marginal losses method chosen it is apparent that it is most accurate, compared to the top down or bottom approach, when the actual flow is equal to the reference flow. However, this does not occur often.

Conclusion

Based on the above consideration, Energinet and Statnett conclude on the following principles for calculating the loss factor on the Skagerrak interconnector.

The TSOs intend to include the converter no-load loss in the linearization. Further, in finding the reference flow, the TSOs will not distinguish between different time-periods within a year, and in order to keep the loss factor both transparent and predictable, it seems favorable to include a loss factor with a yearly adjustment process for the market algorithm. Further, allowing an event based adjustment due to certain circumstances, such as the need for persisting modifications of the HVDC line configuration. As a statistical selection criteria (selection of the reference flow), the yearly median based on hours with a non-zero flow is chosen.

The real losses to be related to the reference flow could be derived by either model, either the "top down" or the "bottom up". In this respect, the “bottom up” model is chosen as the initial model, fitted with the data of the “top down” approach. Further, future updates are based on the “top down” approach. Thus, the TSOs choose a flexible approach, which both will have the detailed calculation on a “component level”, provide optionality in terms of shifting the loss factor if any of the different cables might be in an outage stage, while still allowing to capture variance in control settings based on updates of measurements within the year.

The two methodologies for Skagerrak and NordNed are similar in relation to calculation of both reference flow and the linearized loss component.

The loss factor based on the above described methodology estimates a loss factor at 2.5 % at the reference flow of 946 MW (in year 2017) for Skagerrak.

Appendix 1:

IMPLICIT LOSSES – LOSS FACTORS ON HVDC BORDERS FOR MARKET CLEARING

Transmission losses on HVDC lines can with good approximation be estimated from a function proportional to the square of the flow (load losses) plus a constant factor (no-load losses). Figure 1 shows an example of measured losses on the Storebælt HVDC line.

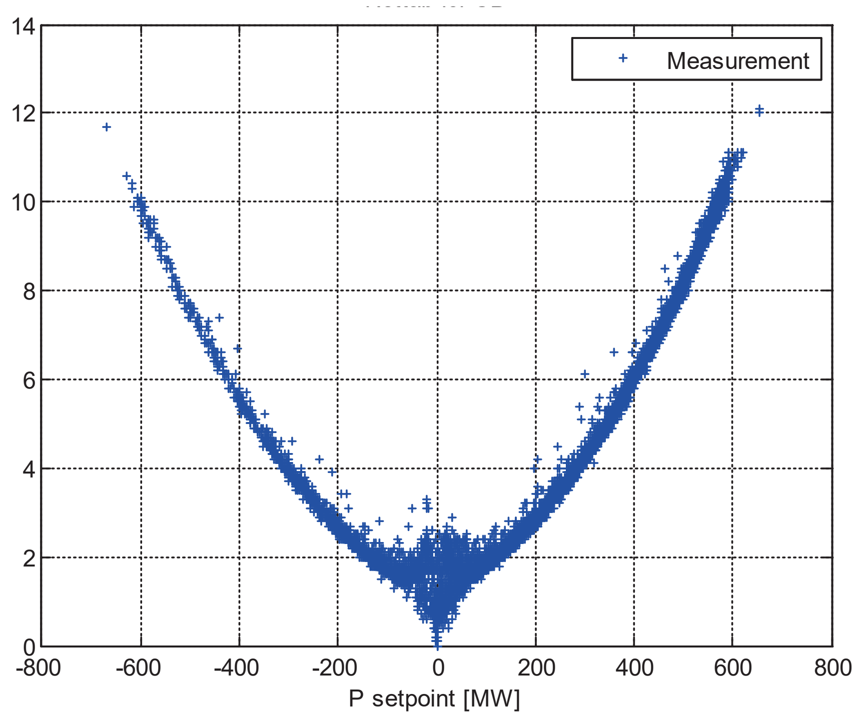


Figure 1 Example of measured losses on Storebælt (SB) for different power flows. Based on settlement data (MWh/h).

Losses can be slightly dependent on the direction of power. A *symmetrical* loss curve is considered. Based on this approximation method the estimated loss curves of the existing Danish HVDC lines are shown in Figure 2.

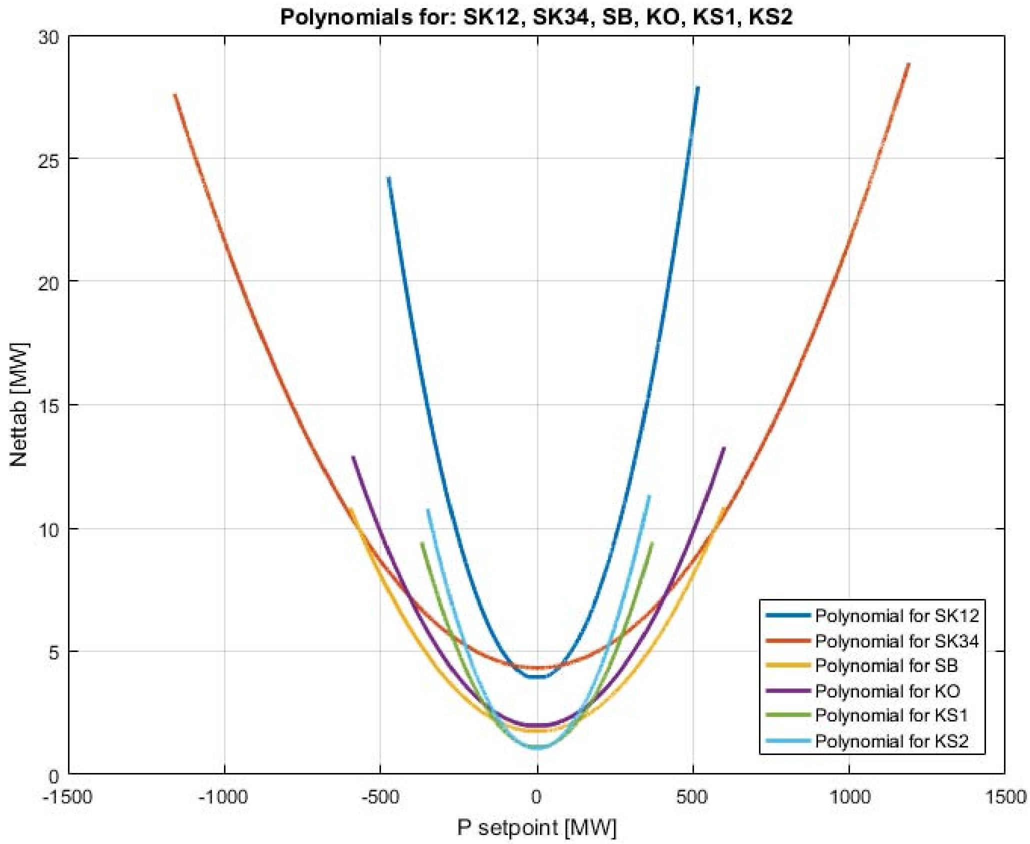


Figure 2 Total losses on existing HVDC lines Skagerrak (SK12, SK34), Storebælt (SB), Kontek (KO), Konti-Skan (KS1, KS2).

Dataset from 2014-2016

When the market clearing model (Euphemia) considers implicit losses only a proportional factor of the flow can be included. This means that the square function has to be linearised near a typical operating point. In theory the factor could be updated for every hour based on a flow forecast. In reality this is not considered as a realistic approach worth the effort as it may require changes at the NEMO and additional processes at the TSO while providing low socio economic benefit.

Losses on HVDC borders consisting of multiple poles (Skagerrak and Konti-Skan) shall be aggregated for each border. On these multi-pole borders the losses depend on the configuration of the dc circuit as well as the load sharing between the poles. This methodology proposes on a *proportional* loading of each pole of the HVDC border (e.g. 50% total multi-pole loading corresponds to 50% on each of the individual poles).

Based on these considerations, the loss factor is calculated by *the hvdc losses at rated NTC divided by the NTC*. This is justified by the fact that the HVDC lines have a “high” utilisation factor and that “average losses” are not at “average flow” due to the losses increasing by the square of the flow.

The resulting square loss curves are shown in Figure 3 and Figure 4.

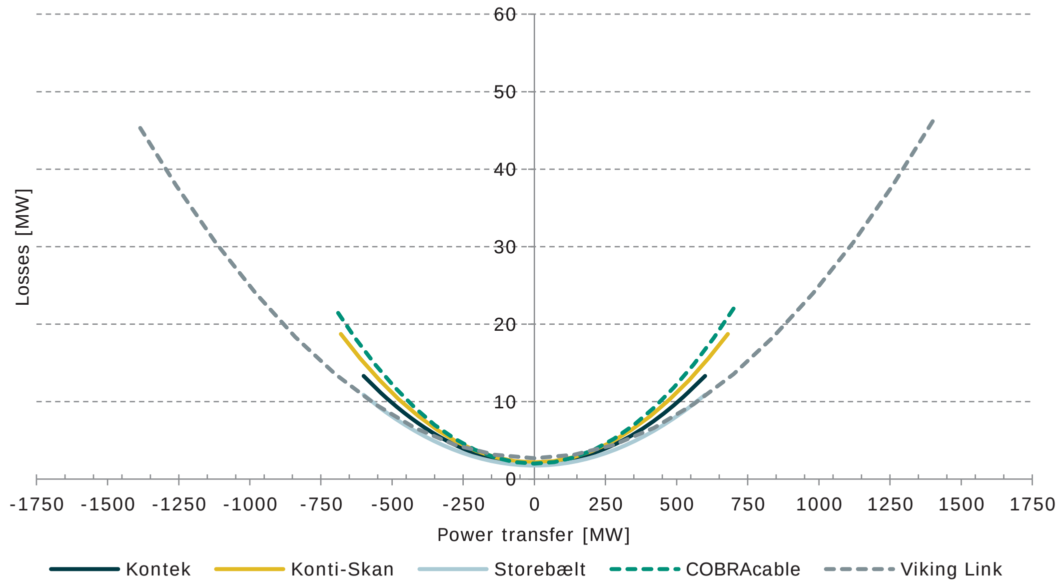


Figure 3 Estimated total losses on existing (solid line) and future (dashed line) HVDC lines for "normal" capacity HVDC borders.

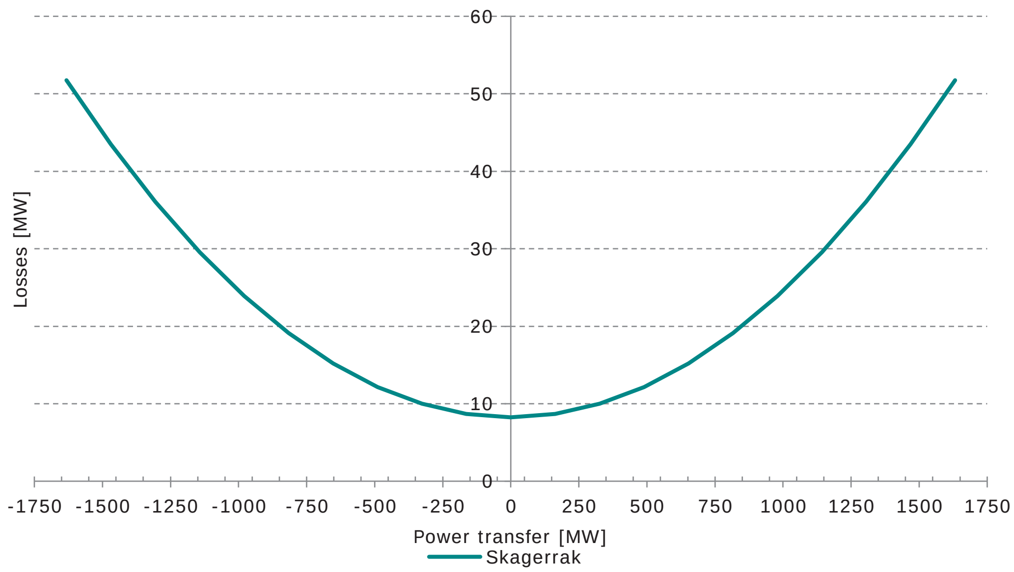


Figure 4 Estimated total losses on Skagerrak

The losses on the future links (dashed lines) are estimated and shall be updated prior to commissioning.

Kriegers Flak back-to-back HVDC link (2018) is not considered as the tie lines on this border will consist of two AC cables while the back-to-back link is located inside the Core region.

The resulting loss factors are shown in the table below, which are calculated based on the max flow.

	Existing HVDC borders					New HVDC borders	
	Kontek	Konti-Skan	Skagerrak	Storebælt		COBRAcable	Viking Link
Border	DK2-GE	DK1-SE3	DK1-NO2	DK1-DK2		DK1-NL	DK1-NL

NTC from-to	-600	-680	-1632	-600		-700	-1400
NTC to-from	600	740	1632	600		700	1400
Loss factor	0.022	0.028*	0.032	0.018		0.031	0.033

*) By request of Svenska Kraftnät implicit losses will not be considered on Konti-Skan.

The above table and related loss factors have to be updated, once there is a decision on having symmetrical capacities or not.

The loss factors are rounded to the two most significant decimal places.

Figure 5 and Figure 6 show the losses which will be considered implicitly in the market clearing.

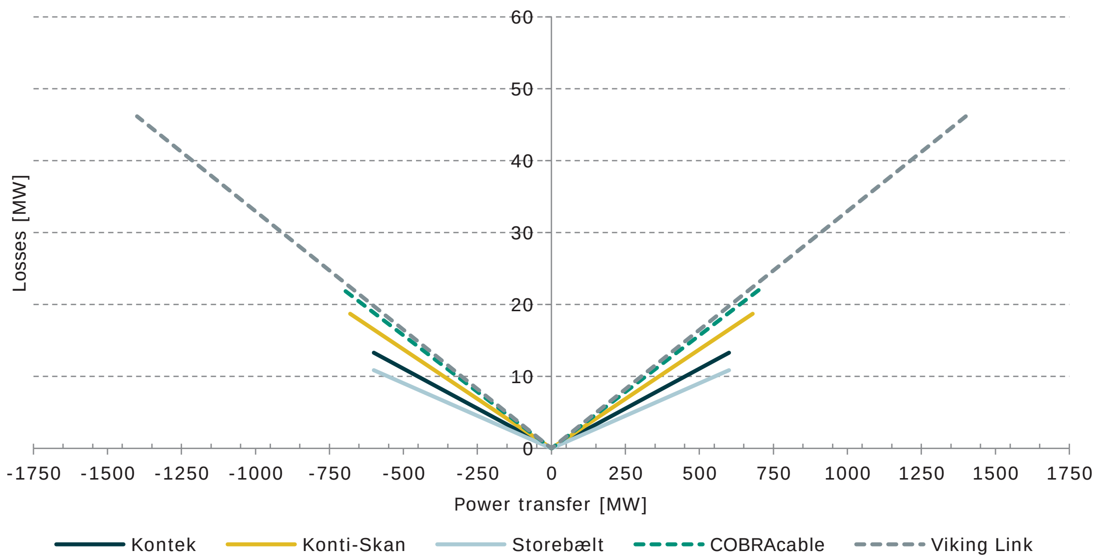


Figure 5 Loss factor on existing (solid lines) and future (dashed line) HVDC lines for "normal" capacity HVDC borders.

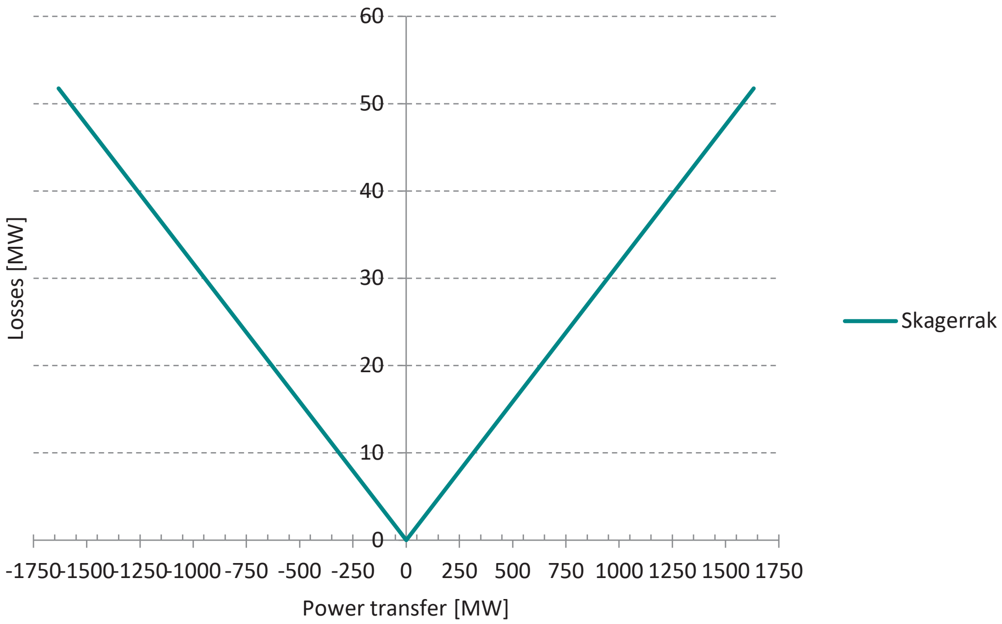


Figure 6 Loss factor on existing (solid lines) and future (dashed line) HVDC lines for "large" capacity HVDC borders.

Reporting

Annual report to the NRA could be good. In order to make the assessment and following adjustment of the loss factor more precise and efficient it is suggested to start a collection of data for the below table.

HVDC border	Capacity A-B [MW]	Capacity B-A [MW]	Transferred power [GWh]	Physical losses [MWh]	Implict losses [GWh]
xx	..	..			

Process for update of loss factors

If modifications of the HVDC line configuration lead to a change of the loss factor by more than e.g arbitrarily chosen 20 % (for instance due to a cable failure or adding a new pole) and the situation is expected to persist for more than one month the TSOs should be able to request NEMOs to update the factors with a one week notice after notifying the NEMOs and NRAs.

Allocation of reserves on an HVDC border could affect the capacity made available to the market. This may also lead to an updated calculation of the loss factors.

The update shall follow the principles in this methodology.

ENERGINET Statnett

Appendix 2:

INNHOLD

INNLEDNING

Dette dokumentet er en beskrivelse av et forsøk på å implementere en makro i Excel som utfører tapsberegninger i de fire Skagerrak-kablene og tilhørende omformeranlegg. Datagrunnlaget for implementasjonen er et utvalg tekniske rapporter fra ABB/ASEA, som har levert omformeranleggene, og tilsvarende fra Nexans/Alcatel/Prysmian, som har levert kablene.

DATAGRUNNLAG

Datagrunnlaget for beregningene er hentet fra en rekke tekniske rapporter. For omformerne er disse Skagerrak "HVDC Overføring Tapsberegning" fra ASEA for SK1 og SK2, og "Determination of losses" fra ABB for SK3 og SK4 (to forskjellige rapporter). For motstand i sjøkablene er "Kontrakt av 27. september 1973 mellom Norges vassdrags- og elektrisitetsvesen og Standard Telefon og Kabelfabrik A/S for levering av 2 sjøkabler for likestrømsoverføring mellom Norge og Danmark" brukt for SK1 og SK2, "Skagerrak 3 Dokumentasjon" for SK3, og "Design Description, Submarine Cable Shallow Water" fra Nexans for SK4. Mostand for luftlinjer og elektroder er hentet fra et regneark med detaljerte beregninger av resistanser for ulike linjer. Se vedleggene for oversikt over komponentene i omformeranleggene som er tatt med i beregningene.

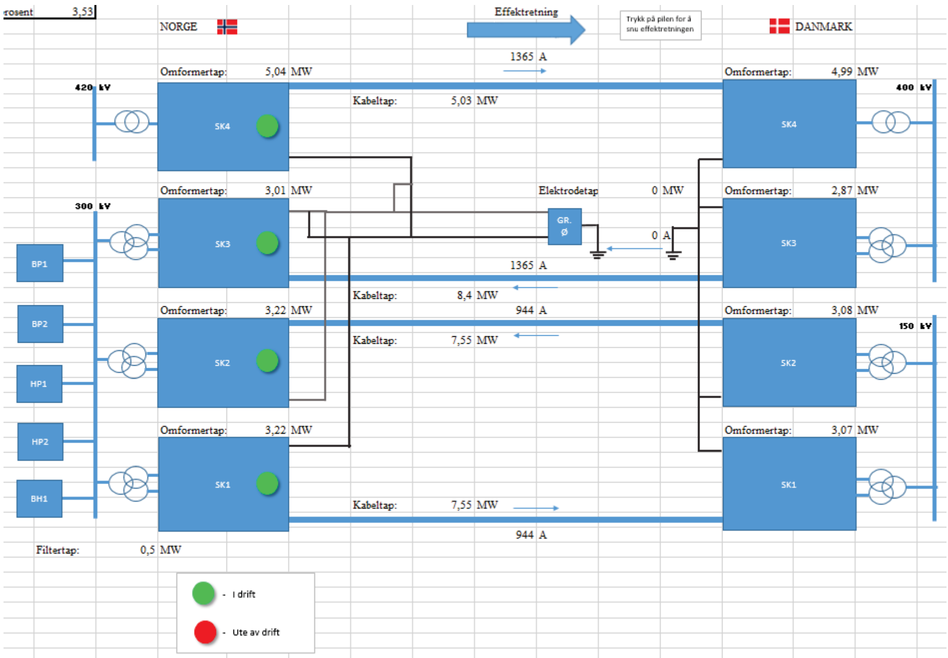
ANTAGELSER

For å muliggjøre beregningene i Excel, har en rekke antagelser og forenklinger blitt gjort. Det har blitt antatt (med unntak av luftlinjene til SK1-3 hvor man kan velge ledertemperatur på enten 20 eller 75 grader) en ledertemperatur på 20 grader, siden det hovedsakelig er resistans for denne temperaturen som er oppgitt i rapportene beregningene er basert på. Videre har det ikke blitt tatt høyde for systemtjenestekapasitet. Det tas ikke hensyn til reaktiv effekt, noe som vil si at tapene som regnes ut vil være et underestimat, da omformerne i SK1-3 i realiteten absorberer reaktiv effekt (det bør også nevnes at det i rapportene antas en effektfaktor på 1). Tapene i de kompenserende filtrene er tatt med, men har utregningene her har blitt noe forenklet. Istedenfor å laste opp filtrene i steg, regnes tapene ut ved å interpolere mellom null last og full last (for SK1-3). Data for filtertap er hentet fra de samme rapportene som omformertapene, mens antall filter ble funnet i en annen rapport fra ABB om harmoniske forstyrrelser [1].

Det bør presiseres at data for omformeranlegg i SK4 er av vesentlig mer detalj enn de øvrige. Her har man oppgitt tap for 0 (no-load), 10, 35, 50, 75 og 100 prosent belastning i rapporten, mens det for SK1-3 kun er oppgitt tall for no-load og full last. Dette medfører at nøyaktigheten for beregningene i disse omformerstasjonene vil være noe lavere enn for SK4 (her må det utdypes hvordan 10, 35, 50, 75-punktene ble regnet ut for SK1-3). Sammenligner man tapskurvene til SK4 med SK1-3 ser man at den er mindre konkav, noe som betyr at man muligens underestimerer tapene i SK1-3 mellom no-load og full last.

BRUKERGRENSESNITT

For å gjøre det enklest mulig for den som skal bruke modellen for tapsestimering, er dataene lagt i egne regneark for hver pol, med en enkel tegning av HVDC systemet som første ark:



Figur 4: Skisse av SK1-4 brukt som brukergrensesnitt i regnearket

Da er det bare velge hvilke poler som er i drift (grønn angir i drift/rød angir ute av drift), effektretning (angis og kan endres ved å krykke på blå pil) og samlet overføring på de polene som er i drift. Deretter startes tapsberegningen ved å trykke på knappen **Kjør**.

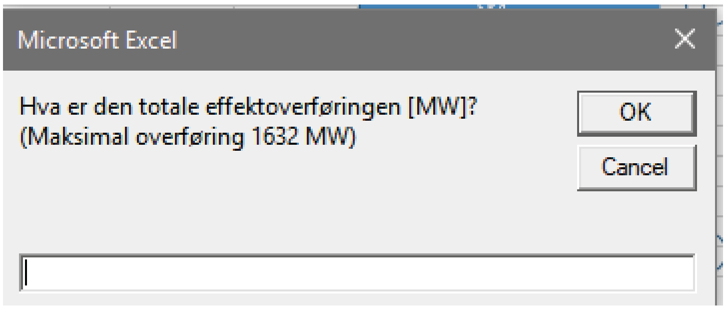
Informasjon om tapene i hver pol vises i nærliggende celler, som man kan se av bildet. Dette inkluderer omformertap, strøm (med retning), tap i DC kabel/ledning og elektrodestrøm.

Øverst i høyre hjørne presenteres de beregnede tapene ved den spesifiserte effektoverføringen på de ulike polene:

Total effekt	1632	MW	Tap i prosent	3,53
Totale tap	57,53	MW		
Effektfordeling				
SK1	236	MW		
SK2	236	MW		420
SK3	478	MW		
SK4	682	MW		
Tap				
SK1	13,84	MW		
SK2	13,85	MW		
SK3	14,28	MW		
SK4	15,06	MW		300

Figur 5: Hovedinformasjon tap med gitt effektoverføring på de ulike polene.

Her vises total effektoverføring, totale tap, effektfordeling i de ulike kablene, og tap som prosentandel av total overført effekt. Videre har man en "kjør"-knapp, som trykkes for utføre beregningene. Trykker man på den, fås dette vinduet opp midt på skjermen:

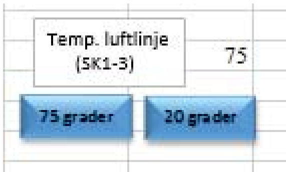


Figur 6: Vindu for valg av effektoverføring, alle poler i drift

I dette vinduet skriver man inn total effektoverføring, trykker OK, så kjøres makroen, og alle cellene oppdateres med nye verdier. Dersom man skylle krysse ut vinduet, eller skriver inn en effekt som er høyere enn overføringskapasiteten, settes alle cellene til null. Overføringskapasiteter er referert til sendende ende.

Temperatur i luftlinjer

Nede i høyre hjørne av modellen finner man denne:

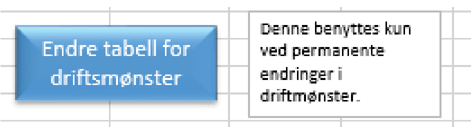


Figur 7: Knapper for valg av temperatur DC luftlinjer SK1-3

Her velges temperaturen i luftlinjene for SK1-3 før kjøring. Økende temperatur i en leder gir høyere resistans, og i dette tilfellet vil 75 grader gi ca. 20 % større resistans enn 20 grader (det kan legges inn interpoleringsmuligheter her dersom dette er ønskelig, slik at man kan velge en temperatur mellom 20 og 75 grader). Det at man kan velge temperaturen her er egentlig uriktig, da man kan velge temperatur i lederne uavhengig av strømmen. I virkeligheten gir større strøm høyere ledetemperatur. Man kan heller se på det som oppveiende for mulige underestimater andre steder i beregningene, eller simpelthen sette temperaturen til 20 grader slik at det er konsistens med antagelsene i resten av beregningene.

Driftsmodi

Nede i høyre hjørne av modellen finner man denne knappen:



Figur 8: Mulighet for å endre tabell for driftsmønster.

Ved å trykke på **Endre tabell for driftsmønster**, kommer det opp en tabell med 16 ulike driftsmodi, vist i Tabell 1. Den inneholder 16 ulike kombinasjoner med Pol 1, 2, 3 og 4 i drift.

Driftmønster

DRIFTSMØNSTER

NR	Kabel kon	Rekkf	NTC SM	NTC 12	NTC 34	FRR	FCR	ATC 12	ATC 34
1	1+2+3+4	34+12	1632	472	1160	100	10	472	1160
2	1+2+3	3+12	802	472	330	100	10	472	230
3	1+2+4	4+12	953	472	481	100	10	472	381
4	1+3+4	34+1	1387	227	1160	100	10	227	1060
5	2+3+4	34+2	1387	227	1160	100	10	227	1060
6	1+2	12	472	472	0	0-100	0-5	372-47	0
7	2+3	3+2	330	0	330	0-100	0	0	230-33
8	1+4	4+1	915	233	682	0-100	0-10	233	582-68
9	3+4	34	1160	0	1160	100	10	0	1060
10	1+3	3+1	710	233	477	0-100	0	233	377-47
11	2+4	4+2	915	233	682	0-100	0-10	233	582-68
12	1	1	227	227	0	0	0	227	0
13	2	2	227	227	0	0	0	227	0
14	3	3	330	0	330	0-100	0	0	230-33
15	4	4	481	0	481	0-100	0-10	0	381-48
16	0	0	0	0	0	0	0	0	0

Hent siste innstillinger | Hent standardinnstillinger | Lukk

Endre verdier i tabell:

SK1 Pmaks, ikke i bipol | SK1 Pmaks, i bipol | SK34 Pmaks

SK2 Pmaks, ikke i bipol | SK2 Pmaks, i bipol | SK12 Pmaks

SK3 Pmaks, ikke i bipol | SK3 Pmaks, i bipol

SK4 Pmaks, ikke i bipol | SK4 Pmaks, i bipol | Oppdater tabell

Tabell 1: Oversikt over 16 ulike tilgjengelige driftsmodi for Skagerrak forbindelsene.

Det er ikke nødvendig å gå inn her med mindre man skal endre på kapasitetene for noen av de 16 driftsmodiene. Kapasitetene for de 16 driftsmodiene er hardkodet i modellen og kan alltid hentes fram ved å trykke **Hent standardinnstillinger**.

Det er mulig å endre kapasitetene ved å legge inn nye kapasiteter nederst og deretter trykke **Oppdater tabell**. Her kan man angi 10 nye kapasiteter, f.eks. **SK1 Pmaks, ikke i bipol**. Når man trykker **Oppdater Tabell**, så brukes denne kapasiteten i driftsmodi hvor SK1 driftes uten SK2, dvs. kapasitetene for driftsmodi 4, 8, 10 og 12 blir oppdatert.

For å gå ut av vinduet trykker man **Lukk**.

DRIFTSMØNSTER

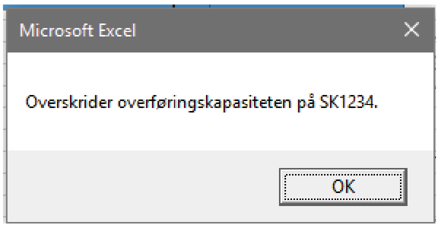
Oppdatert driftsinstruks med kapasiteter med 16 ulike driftsmodi, vist i tabellen nedenfor, ble mottatt av D&M ved Trond A. Jensen på e-post den 14. mars 2018.

Normalsituationer som ikke krever omkobling i HVDC-anleggene											
NR	Kabel kombi-nasjoner	Rekkefølge opplasting	NTC Sum korridor (MW)	NTC bipol 12 (MW)	NTC bipol 34 (MW)	FRR (MW)	FCR (MW)	ATC bipol 12 (MW)	ATC bipol 34 (MW)	Kommentar	Alternativt DM for drift med unntak for høy elektrodestrøm (inntil 40 timer)
1	1+2+3+4	34+12	1632	472	1160	100	10	472	1060		
2	1+2+3	3+12	802	472	330*	100	10	472	230	* NTC kun 330 MW på pol 3, hensynta elektrodestrøm.	20
3	1+2+4	4+12	953	472	481*	100	10	472	381	* NTC kun 481 MW på pol 4, hensynta elektrodestrøm.	18
4	1+3+4	34+1	1387	227	1160	100	10	227	1060		
5	2+3+4	34+2	1387	227	1160	100	10	227	1060		
6	1+2	12	472	472	0	0-100	(0-5)**	372-472	0	Leveranse av systemtjenester vil kun være aktuelt når ENDK er ledende. Begrensninger i FRR leveransen.	
7	2+3	3+2	330	0*	330*	0-100	0	0	230-330	* NTC kun 330 MW på pol 3, hensyntatt elektrodestrøm. Begrensninger i FRR leveransen.	19
8	1+4	4+1	915 NO2>DK1 481 DK1>NO2	233	682	0-100	(0-10)	233	582-682	Reduksjon retning nord pga. elektrodestrøm da polaritet på SK4 må endres manuelt ved endring av retning	
9	3+4	34	1160	0	1160	100	10	0	1060		
10	1+3	3+1	710	233	477	0-100	0	233	377-477	Begrensninger i FRR leveransen.	
11	2+4	4+2	915 NO2>DK1 481 DK1>NO2	233	682	0-100	0-10	233	582-682	Reduksjon retning syd pga. elektrodestrøm da polaritet på SK4 må endres manuelt ved endring av retning	
12	1	1	227	227	0	0	0	227	0	Ikke teknisk mulig å levere systemtjenester.	
13	2	2	227	227	0	0	0	227	0	Ikke teknisk mulig å levere systemtjenester.	
14	3	3	330	0	330*	0-100	0	0	230-330	NTC reduksjon pga elektrodestrøm. Begrensninger i FRR leveransen.	22
15	4	4	481	0	481*	0-100	0-10	0	381-481	NTC reduksjon pga elektrodestrøm.	25
16	0	34+12	0	0	0	0	0	0	0	Plan må lages i planverktøy.	

Figur 9: Tabell for driftsmønster SK1-4

Kort oppsummert er opplastningsrekkefølgen slik: Polene SK3 og SK4 lastes opp først, deretter SK1 og SK2. Hvis noen av polene er utilgjengelige, f. eks SK3, vil SK4 lastes opp til maksgrense for elektrodestrømmen nås (1000 A). Det kan nevnes at dersom alle kabler er tilgjengelige for overføring, vil man få noe mindre tap ved å laste de siste ca. 200 MW på SK1/2, men tabellen ble fulgt slavisk for enkelhets skyld. Det bemerkes at SK1 har strømretning sørover (dvs. fra Norge til Danmark), SK2 og SK3 nordover (dvs. fra Danmark til Norge). Dette innebærer at SK2 og SK3 driftes sammen (driftsmønster 7) gir begrensing i samlet overføringskapasitet på 330 MW på grunn av maksgrense på elektrodestrøm.

Dersom man skulle velge en effektoverføring som er høyere enn kapasiteten til polene som er i drift, vil alle cellene settes til null, og dette vinduet kommer opp:



Figur 10: Advarselsvindu, maksgrense for effektoverføring

IMPLEMENTASJON I EXCEL

For å regne ut tapene har det blitt skrevet funksjoner i Excels innebygde programmeringsspråk, Visual Basic for Applications. For å interpolere mellom de ulike datapunktene, brukes if-elseif setninger:

```
ElseIf (x >= 10 And x < 35) Then
    tap_likeretter = Range("B14").Value + ((Range("B15").Value - Range("B14").Value) / (Range("A15").Value - Range("A14").Value)) * (x - Range("A14").Value)
```

Figur 11: Utdrag fra VBA-kode, Tap_SK4_sør

	A	B	C
1	Data SK4 omformer		
2	Kristiansand:		
3			
4	Grunndata Omformer		
5	Nominell effekt [MW]	715	
6	Nominell reaktiv effekt [Mvar]	85	
7	Nominell DC spenning [kV]	500	
8	Nominell Strøm [A]	1430	
9			
10	Tapsdata er tatt fra rapport 1JNL100182-648		
11			
12	Effektoverføring %	Likeretter [kW]	Inverter [kW]
13	0	360,4	360,4
14	10	950	926,4
15	35	1898	1850,1
16	50	2550,9	2417,4
17	75	3813,7	3793
18	100	5308,9	5360

Figur 11: Utklipp fra regneark "Tap SK4 omf"

Her ser man altså (med utgangspunkt i formelen for lineær interpolasjon) at setningen i Visual Basic svarer til å interpolere mellom 10 og 35 % belastning. Det er skrevet 8 funksjoner som regner ut tapene, en for hver kabel og retning (det er litt forskjell i tapene avhengig av om man kjører en bestemt omformer som inverter eller likeretter, i tillegg tas det hensyn til at noe av effekten går tapt i ledere. Eksempelvis med SK4: 100 % belastning i likeretteren gir ca. 99 % belastning i inverteren). I hver tapsfunksjon er det også lagt inn setninger som regner ut ledertap ut i fra strøm (regnes ut fra nominell spenning og overført effekt) og resistans.

"Hovedmakroen" baserer seg en representasjon av driftstilstanden av de ulike kablene som boolske variabler, hvor True representerer "I drift" og False "Ute av drift". Brukeren velger hvilke kabler som er i drift, skriver inn effektoverføring, og så evalueres den gitte driftssituasjonen og opplastningsrekkefølgen ut i fra hvilke kabler man har i drift og overført effekt, i tillegg til effektretning og temperatur for luftlinjer SK1-3. Egentlig er denne makroen bare en stor nøstet if-setning (se kommentarer i VBA-kode for mer informasjon).

VEDLEGG

Omformertap SK1-2

Kristiansand:

Objekt	Tomgångs förluster kW	Belastnings- förluster kW
Tyristorventiler	54	2 196
Strömriktartransformatorer	426	2 770
Fasreaktorer	-	17
Linjereaktor	-	37
Glättningsreaktor	2	263
Övertonsfilter	137	12
Källspänningstransf. Mätspänningsdelare Strömtransformatorer och mättransduktorer	1	5
Totalt hjälpkraftbehov till kylutrustning och kontrollutr.	765	-
SUMMA	1385	5300

Tjele:

Objekt	Tomgångs förluster kW	Belastnings- förluster kW
Tyristorventiler	54	2 196
Strömriktartransformatorer	398	2 937
Fasreaktorer	-	17
Linjereaktor	-	37
Glättningsreaktor	2	265
Övertonsfilter	141	16
Källspänningstransf. Mätspänningsdelare Strömtransformatorer och mättransduktorer	1	5
Totalt hjälpkraftbehov för kylutrustn. och kontrollutrustn.	765	-
SUMMA	1361	5473

[2]

Omformertap SK3

	No-load losses	Load losses Rectifier	Load losses Inverter	
Kristiansand				
Converter Transformers	301.5	1613.2	1613.2	kW
Thyristor Valves	14.4	753.1	758.3	kW
Smoothing Reactors	0	119.8	119.8	kW
AC Filters	0	123.4	127.3	kW
DC Filters	0	9.4	9.6	kW
Converter transformer coolers	5.2	15.7	15.7	kW
Thyristor valve coolers	5	76	76	kW
Other aux. consumption	13.2	13.2	13.2	kW
Total losses	339.3	2724	2733	kW
Tjele				
Converter Transformers	307.9	1587	1587	kW
Thyristor Valves	14.4	753.1	758.4	kW
Smoothing Reactors	0	119.8	119.8	kW
AC Filters	0	223.1	244.8	kW
DC Filters	0	14.2	14.2	kW
Converter transformer coolers	4	16	16	kW
Thyristor valve coolers	5	76	76	kW
Other aux. consumption	13.2	13.2	13.2	kW
Total losses	344.5	2802	2829	kW

[3]

Omformertap SK4

	LOAD LOSSES. KRISTIANSAND [kW]					
	Rectifier					
P [%]	**0%**	**10%**	**35%**	**50%**	**75%**	**100%**
IGBT valves [kW]	60,6	358,3	1106,3	1547,3	2294,8	3081,5
Valve cooling [kW]	35,5	84,5	97,0	104,5	117,0	132,0
Cell capacitors [kW]	2,9	2,0	7,7	14,3	30,9	50,8
HF dampers [kW]	0,0	7,1	8,3	9,7	13,2	18,0
Power transformers [kW]	213,0	103,2	243,6	393,9	750,9	1261,2
Cooling of power transformers [kW]	13,5	0,0	0,0	0,0	13,5	13,5
Converter reactors [kW]	0,0	2,2	26,5	54,2	122,4	218,9
Smoothing reactors [kW]	0,0	0,8	9,2	18,8	42,2	74,8
AC PLC/RI reactors [kW]	0,0	0,3	3,2	6,6	14,9	26,9
DC PLC/RI reactors [kW]	0,0	0,3	3,7	7,5	16,9	30,0
Auxiliary losses [kW]	34,9	20,2	20,3	20,3	20,5	20,6
BR2 Capacitors [kW]	0,0	0,1	1,2	2,4	5,5	9,7
HF Filter Capacitor [kW]	0,0	0,8	0,8	0,8	0,8	0,8
DC Capacitor [kW]	0,0	9,8	9,8	9,8	9,8	9,8
Total Load Losses [kW]	**360**	**589**	**1538**	**2190**	**3453**	**4948**
Total Operating Losses [kW]	**360**	**950**	**1898**	**2551**	**3814**	**5309**

	LOAD LOSSES. KRISTIANSAND [kW]					
	Inverter					
P [%]	**0%**	**10%**	**35%**	**50%**	**75%**	**100%**
IGBT valves [kW]	60,6	338,6	1068,3	1518,4	2316,2	3173,6
Valve cooling [kW]	35,5	82,0	97,0	104,5	119,5	134,5
Cell capacitors [kW]	2,9	2,0	7,6	14,0	30,5	47,0
HF dampers [kW]	0,0	7,1	8,3	9,7	13,1	18,0
Power transformers [kW]	213,0	102,0	234,9	372,9	709,5	1222,5
Cooling of power transformers [kW]	13,5	0,0	0,0	0,0	13,5	13,5
Converter reactors [kW]	0,0	2,1	25,8	53,0	120,6	218,1
Smoothing reactors [kW]	0,0	0,7	9,0	18,4	41,7	74,8
AC PLC/RI reactors [kW]	0,0	0,3	3,1	6,4	14,7	26,7
DC PLC/RI reactors [kW]	0,0	0,3	3,6	7,4	16,7	30,0
Auxiliary losses [kW]	34,9	20,2	20,3	20,3	20,5	20,6
BR2 Capacitors [kW]	0,0	0,1	1,2	2,4	5,5	9,7
HF Filter Capacitor [kW]	0,0	0,8	0,8	0,8	0,8	0,8
DC Capacitor [kW]	0,0	9,8	9,8	9,8	9,8	9,8
Total Load Losses [kW]	**360**	**566**	**1490**	**2138**	**3433**	**5000**
Total Operating Losses [kW]	**360**	**926**	**1850**	**2499**	**3793**	**5360**

	LOAD LOSSES, TJELE [kW]					
	Rectifier					
P [%]	**0%**	**10%**	**35%**	**50%**	**75%**	**100%**
IGBT valves [kW]	60,6	358,3	1106,3	1547,3	2294,8	3087,4
Valve cooling [kW]	34,5	81,5	93,5	99,5	110,0	120,5
Cell capacitors [kW]	2,9	2,0	7,7	14,3	30,9	51,6
HF dampers [kW]	0,0	7,1	8,3	9,7	13,2	18,0
Power transformers [kW]	213,0	103,2	243,6	393,9	750,9	1267,8
Cooling of power transformers [kW]	13,5	0,0	0,0	0,0	13,5	13,5
Converter reactors [kW]	0,0	2,2	26,7	54,6	123,3	220,6
Smoothing reactors [kW]	0,0	0,7	9,2	18,7	42,0	74,5
AC PLC/RI reactors [kW]	0,0	0,3	3,2	6,6	14,9	26,9
DC PLC/RI reactor [kW]	0,0	0,3	3,7	7,5	16,9	30,0
Auxiliary losses [kW]	21,2	5,3	2,3	2,3	2,4	5,4
BR2 Capacitors [kW]	0,0	0,1	1,2	2,4	5,5	9,7
HF Filter Capacitor [kW]	0,0	0,8	0,8	0,8	0,8	0,8
DC Capacitor [kW]	0,0	9,8	9,8	9,8	9,8	9,8
Total Load Losses [kW]	**346**	**572**	**1516**	**2168**	**3429**	**4937**
Total Operating Losses [kW]	**346**	**917**	**1862**	**2513**	**3775**	**5282**

	LOAD LOSSES, TJELE [kW]					
	Inverter					
P [%]	**0%**	**10%**	**35%**	**50%**	**75%**	**100%**
IGBT valves [kW]	60,6	338,6	1068,3	1518,4	2316,2	3180,2
Valve cooling [kW]	34,5	81,5	92,0	98,0	110,0	122,0
Cell capacitors [kW]	2,9	2,0	7,6	14,0	30,5	47,7
HF dampers [kW]	0,0	7,1	8,3	9,7	13,1	18,0
Power transformers [kW]	213,0	102,0	234,9	372,9	709,5	1222,5
Cooling of power transformers [kW]	13,5	0,0	0,0	0,0	13,5	13,5
Converter reactors [kW]	0,0	2,1	26,0	53,4	121,5	219,7
Smoothing reactors [kW]	0,0	0,7	9,0	18,4	41,6	74,5
AC PLC/RI reactors [kW]	0,0	0,3	3,1	6,4	14,7	26,7
DC PLC/RI reactors [kW]	0,0	0,3	3,6	7,4	16,7	30,0
Auxiliary losses [kW]	21,2	5,3	2,3	2,3	2,4	5,4
BR2 Capacitors [kW]	0,0	0,1	1,2	2,4	5,5	9,7
HF Filter Capacitor [kW]	0,0	0,8	0,8	0,8	0,8	0,8
DC Capacitor [kW]	0,0	9,8	9,8	9,8	9,8	9,8
Total Load Losses [kW]	**346**	**551**	**1467**	**2114**	**3406**	**4981**
Total Operating Losses [kW]	**346**	**896**	**1813**	**2460**	**3751**	**5326**

[4]

REFERANSER

[1] "Skagerrak 4 - Harmonic Performance Study", ABB

[2] "Skagerrak HVDC tapsberegning" (SK1-2), ASEA

[3] "Determination of losses" (SK3), ABB

[4] "Determination of losses" (SK4), ABB

Analyses on the effects of implementing implicit grid losses in the Nordic CCR

Publication date,

30 April 2018

Executive summary

The purpose of this study is to analyze the effects of implementing implicit grid losses on the DC-interconnectors connecting Nordic bidding zones to each other and externally.

The reason for investigating implicit grid losses is the fact that losses occur when power flows over the interconnector between bidding zones. Today the losses are handled explicitly by the TSOs, who ensure that the necessary power is acquired in order to compensate for the losses. When grid losses are handled explicitly the costs of grid losses are not taken into account in the price coupling algorithm but as price-independent bids as input for the algorithm. When the price coupling algorithm is not taking the losses into account, power is allowed to flow even when the price difference and hence the congestion income in the day-ahead market is smaller than the marginal cost of grid losses, thus causing a socioeconomic loss for the Nordic area.

Grid losses are a negative external effect, which is economic inefficient, and cause a welfare economic loss. This loss can be corrected by internalizing the external effect in the power market by implementing implicit grid losses on the interconnectors. When implementing implicit grid losses the market coupling algorithm (Euphemia) will no longer allow flow of power unless the price difference between the bidding zones is greater than or equal to the marginal cost of the grid losses.

Implementing implicit grid losses on DC-interconnectors will have the effect that more power flows through the AC grid, and it is generally not feasible to implement grid losses on AC-interconnectors. When only implementing grid losses on DC-interconnectors the effects will among others be an increased flow in the AC-grid. This makes it important to analyze the effects on the AC grid to make sure, that the increased costs of grid losses in the AC-grid do not exceed the economic gains from internalizing grid losses on the DC-interconnectors.

The study has been carried out using three approaches;

1. a theoretical discussion of implicit grid losses,
2. numerical simulations of market effects in the day-ahead market, and
3. a statistical methodology for the assessment of the physical AC-grid losses.

The study only takes the interconnectors connected to the Nordic bidding zones into account. The impact to the bidding zones outside the Nordics are not in the scope of this report. A more comprehensive analysis would include the economic welfare calculations for the whole NWE region.

The study finds that implementing implicit grid losses on the DC-interconnectors in the Nordics produces an economic efficiency gain. Applying equal loss factors on the interconnectors, and therefore overcoming a potential priority problem, would reduce the benefits slightly, but does not have a substantial effect on the positive results for implementing implicit grid losses.

The only deviation is the FennoSkan interconnector. Due to the large increase in AC losses caused by the alternative flow path via the northern part of Sweden and Finland, there is no benefit of implementing implicit losses on FennoSkan. In fact, the results indicate that implementing implicit grid losses on FennoSkan produces a welfare loss.

Table of content

1. Background

As in all parts of the power grid, when power flows on an interconnector losses occur. These losses are handled by the TSOs who ensure that the necessary power is acquired to compensate for the losses. Today there are flows between most bidding zones in the Nordics even though the price difference and hence the congestion income in the day-ahead market is smaller than the marginal cost of the grid losses caused by these flows. The TSOs therefore encounter a cost for losses which cannot be covered by the congestion income from the day-ahead market and therefore it can be argued that these flows cause socioeconomic losses.

Currently, there are two different ways of purchasing grid losses in the Nordics. On some DC-interconnectors, the estimated losses are bought 50 pct. in the importing bidding zone and 50 pct. in the exporting bidding zone in the day-ahead market. In some cases the two TSOs have agreed that the TSO of the exporting bidding zone buys 100 pct. of the estimated losses in the day-ahead market and later the importing TSO compensates 50 pct. financially. The latter method optimises the loss costs of the DC-interconnectors as the losses, at least in theory, are produced by more efficient production units. The losses in the Norwegian, Swedish, Danish and Finnish AC grid are forecasted and bought in the day-ahead market in the form of price independent bids from the TSOs of each bidding zone. In Finland, finer adjustments for the TSO grid losses might be handled in the intraday market.

Unless the costs of grid losses are explicitly introduced to the market participants, grid losses do not influence their behaviour. As such, grid losses are an example of a negative external effect, an unconsidered negative impact of the actions taken by one individual or firm on other market participants. Negative external effects are an economic inefficiency that causes a welfare economic loss. This loss might however be corrected by internalizing the external effect. One way to do this in the power market, is to implement implicit grid losses on the interconnectors. Today implicit grid losses are implemented on some European DC-interconnectors, namely NorNed, IFA, Britned and the Baltic cable (see Figure 1).

When implementing implicit grid losses on DC-interconnectors, the market coupling algorithm (Euphemia) will not allow flow of power over the interconnector unless the price difference between the bidding zones connected by the interconnector is greater than or equal to the marginal cost of the grid losses. The rationale can be described as:

Flow: price difference in day-ahead market ≥ marginal cost of losses

No flow: price difference in day-ahead market < marginal cost of losses

The introduction of implicit grid losses therefore theoretically creates a greater coherence between the market and the physics by internalizing the external effect of grid losses in the algorithm and ensures the optimal socioeconomic use of the interconnectors. These market based implications of implicit grid losses may be observed in the power market, thus it is possible to simulate the market effect of implicit grid losses at the PX simulation facility.

The flow in the AC-grid is not controllable, and the AC-grid losses is an increasing function of flows. However, in general, an introduction of an AC-interconnector loss factor is not feasible. For isolated cases, in which there might be a non-negligible change in the flows at one single AC-interconnector, an introduction of an AC-interconnector loss factor could be possible. However, a simplified representation of the network is used in the Market coupling algorithm (Euphemia) to represent the grid. This implies that only a linear AC loss factor could be introduced. Given that a linear loss factor is a much more simplified approximation for the AC-grids than for the DC-interconnectors, the AC-interconnector loss factor would not accurately reflect the level of losses. The losses in the AC-grid are therefore managed by the tariffs, an arrangement which is less accurate than the implicit approach proposed for the DC-interconnectors.

Implementing implicit grid losses on DC-interconnectors can affect the flows and losses in the AC-grid, which are not managed by implicit arrangements and not directly observable in the power market.

Due to the loss management of the AC-grid by the tariffs, increased flows in the AC-grid (over larger distances) caused by the implicit approach on DC-interconnectors, might result in greater losses than those avoided on the DC-interconnectors. Furthermore, increased flows in the AC-grid can affect already highly congested power lines. Thus, a thorough analysis, taking into account the effect on the AC-grid along with the socioeconomic effects in the power market, is essential in order to assess the overall welfare economic impact from implementing implicit grid losses.

This study aims at analysing the effects of implementing implicit grid losses on DC-interconnectors in the Nordic.

Figure 1. ***Interconnectors where implicit grid losses are implemented today; IFA (GB-FR), Britned (GB-NL), NorNed (NO2-NL) and Baltic cable (SE4-DE).***

2. Limitations of the analysis

In this study, assumptions and limitations have been made which can affect the results. The limitations are described below.

Geographical extension of the analysis: The study only takes into account the interconnectors connected to the Nordic bidding zones and their impact to the Nordic bidding zones. The impact to the bidding zones outside the Nordics are not in the scope of this report. However, it has to be kept in mind that implementing loss factor to an interconnector between a Nordic bidding zone and a bidding zone outside the Nordics has impacts to the latter. This affects the total socioeconomic welfare of the internal energy market. If a Nordic bidding zone is an exporting area, the total socioeconomic welfare could be smaller than calculated in this report due to welfare loss in the receiving area outside Nordics. And symmetrically, if a Nordic bidding zone is an importing area, the total welfare could be larger than calculated in this report due to welfare increase in the sending area outside the Nordic region. A more comprehensive analysis would include the economic welfare calculations for the bidding zones in the whole NWE region.

Estimated changes in cost of losses in AC grid: The methodology for calculating the AC losses is based on loss functions estimated by statistical analysis using linear regression. It has been shown that assuming a straight line to describe the AC loss function is a simplification that might provide a statistically inaccurate fit, especially for the extreme points in the statistical population. This simplification implies that some of the absolute values of the losses are inaccurate, however still providing a good estimate for the *difference* between the simulations for each hour. Linear regression for AC losses has the least accurate fits for SE3 and FI (see annex 9.10). Linear regression is a model that can be fitted to the results of the market coupling algorithm (Euphemia) used in this analysis.

Interplay with tariffs: Both Sweden and Norway have a network tariff reflecting the marginal cost of losses in AC grid. With different flows in the AC grid, due to introduction of implicit losses on DC interconnectors, the Norwegian tariffs would change as these tariffs are calculated weekly based on simulations of power flows in the AC grid. For both countries, it is assumed in the analysis that there is no effect from changed AC-flow on these tariffs, and that these changes do not influence the behaviour of the market participants. This simplification is assumed to result in an underestimation of the total welfare economic effect, but not to a significant degree.

Price effects of TSOs not needing to buy losses explicitly when losses are included in Euphemia: Running the PX simulation facility to produce the results presented in chapter 7, the explicit procurement of losses for the relevant DC interconnectors by TSOs have not been excluded. In the simulations with losses included in the algorithm, these losses are hence procured twice. However this simplification has little impact on the conclusion that inclusion of losses in the market algorithm increases the overall welfare economic result in most simulation cases. There are however impacts on the magnitude of the results, in particular on the distribution of welfare between consumers and producers and on the distribution of welfare between importing and exporting bidding zones.

Valuation of the DC losses in cases without a loss factor differs from the current procurement practices: In the socio-economic welfare calculation when loss factors are not used, DC interconnector losses are valuated at the price of the importing bidding zone. This is done to align the market algorithm's outcomes between cases with and without loss factors, so that they are theoretically comparable from consumer and producer surpluses perspective. This assessment however differs from the current practice of DC losses procurement. On most interconnectors the losses are bought on the exporting end in a cost efficient manner. Therefore, the report outcome should not be seen as a comparison between the current practice for Nordic interconnectors and the connected Nordic bidding zones, but more as an overall indication of the theoretical socio-economic welfare changes of implementing implicit grid losses in the Nordics, given the underlying assumption of the simulations and choices made in welfare calculation.

3. Theoretical explanation of market simulations of implicit grid losses

As explained in chapter 2, the welfare economic effects have been calculated with the simplification of using identical demand curves when losses are procured by TSOs, and when they are procured by the algorithm. To be fully consistent with reality, the price-independent bids from the TSOs should be removed in the simulations with implicit grid losses. However, this assumption has little impact on the final results in terms of market welfare[1]. There are however impacts on the magnitude of the results, on the distribution of welfare between consumers and producers and on the distribution of welfare between importing and exporting bidding zones. In respect of consistency with the market simulations, the same assumption is applied in the theoretical discussion in this chapter.

The consequence of implementing implicit grid losses in the market algorithm is that the market result will reflect that importing bidding zone will receive less energy than what is sent from the exporting bidding zone. The difference reflects the losses occurred in the transportation which is not otherwise taken into account in the market coupling algorithm (Euphemia).

Price Difference	Flow at loss factors				
	0 %	1 %	2 %	3 %	4 %
0 %	≤ 100 pct.	0 pct.	0 pct.	0 pct.	0 pct.
1 %	100 pct.	≤ 100 pct.	0 pct.	0 pct.	0 pct.
2 %	100 pct.	100 pct.	≤ 100 pct.	0 pct.	0 pct.
3 %	100 pct.	100 pct.	100 pct.	≤ 100 pct.	0 pct.
4 %	100 pct.	100 pct.	100 pct.	100 pct.	≤ 100 pct.

Table 1. Flow as a percentage of the capacity on the interconnector at different loss factors and price differences.

The aim of this chapter is to explain from a theoretical perspective the economic effects in terms of price movements, changes to congestion income and consumer and producer surpluses that are expected to be observed in the market simulations of implicit grid losses in chapter 7. We'll show that some effects can be concluded by theory alone, but some are case-dependent and cannot be concluded without numerical simulations. In particular, the latter holds true for the overall welfare effect of implementing implicit losses which has to be assessed numerically.

When implementing implicit grid losses, the market coupling algorithm (Euphemia) will no longer allow flow of power over the interconnector unless the price difference between the bidding zones

[1] In the market algorithm, the TSOs' demand for loss energy is part of the calculated consumer surplus. However, in reality the TSOs' demand curves are a technical implementation of a welfare economic cost (energy losses) that carries no consumer surplus. Thus, removing the TSOs' bid curves in the simulations will cause a non-existing consumer loss to occur, which will have to be corrected for. This correction is in the opposite direction of, and (likely) at the same magnitude as, the error introduced by not removing the bid curves. Thus, by not removing the TSO bids in the implicit loss simulations, we are sure to be calculating comparable solutions in both simulations with and without implicit grid losses,

connected by the interconnector is greater than or equal to the marginal cost of the grid loss. As illustrated in Table 1 the effect of the flow as a percentage of the capacity on the interconnector depends on the loss factor and the price difference on the given interconnector.

The assumption that the TSOs currently are buying grid losses outside the energy market is generally *not* correct for Nordic interconnectors. For example, for the Skagerrak interconnector, Statnett and Energinet currently provide price-independent bids in the energy market to cover for the DC-losses. For the FennoSkan interconnector, the exporting TSO (Svenska Kraftnät or Fingrid; in prevailing market situations mostly Svenska Kraftnät) buys the loss energy price-independently on the day-ahead market and half of the value of the purchased loss energy is compensated financially by the importing TSO. On the Estlink interconnector, Fingrid and Elering both buy half of the expected loss energy from the day-ahead market. By procuring the loss energy from the exporting bidding zone, the efficiency and the loss costs to the TSO and hence to the society are optimised. In the exporting area which has lower energy price, the loss energy at least in theory is produced in a more economical way.

For ease of arguments in the theoretical discussion below, we consider situations with only two connected bidding zones. However it should be noted that the situation in reality is more complex since more bidding zones are interconnected. Thus, in the real world, the effects on prices and volumes will spill over to other bidding zones and generate feedbacks on the initial price and volume changes. These market-repercussions will influence the magnitude of the initial changes, but not the direction. (All market repercussions are however considered in the numerical simulations.)

In the simplified example below, the two bidding zones are noted as exporting market area (E) and importing market area (M). Since implementing implicit grid losses between two bidding zones have different effect in uncongested and in congested situations, the discussion below is separated into two sections accordingly.

3.1 Impact in uncongested situations

Let's first consider the uncongested situation without implicit grid losses as illustrated in Figure 2. In a market where implicit grid losses are not implemented on interconnectors[2], the market does not react to the marginal cost of grid losses, and thus a standard market clearing will be one where the prices are the same in both bidding zones. This solution is illustrated by the price (P^1) being equal in both bidding zones. Thus, the exported and imported volumes are equal as illustrated by the two solid blue horizontal lines in the figure. In this situation, no congestion income is generated. In the exporting bidding zone, the trade generates a benefit for the generators due to a price increase (P^1 - P^{E*}), and for the consumers in the importing bidding zone due to a price decrease (P^{M*} - P^1). There is also a consumer loss in the exporting are due to increased prices and a producer loss in the importing area due to reduced prices but these negative effects are always smaller than the

[2] By assumption being managed by TSO procuring the grid losses outside the energy markets

positive ones, the net welfare economic benefit of trade is illustrated by the two grey shaded triangles.

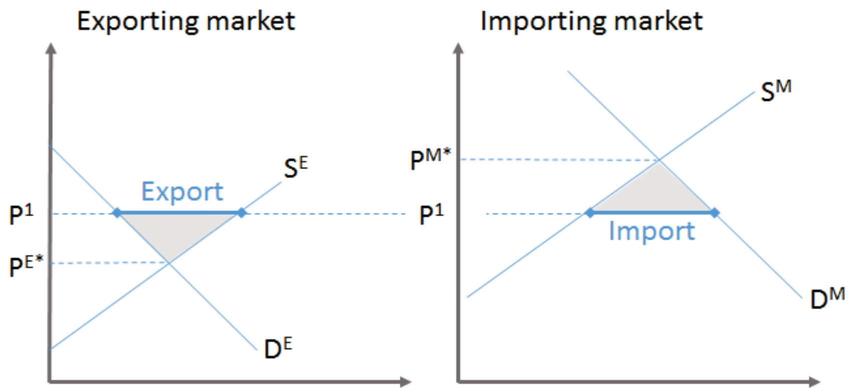


Figure 2. Uncongested situation with no implicit grid losses.

When implementing implicit grid losses, the importing bidding zone will receive less energy than what is sent from the exporting bidding zone due to energy loss (as illustrated in Figure 3 by the shorter green solid line in the right hand figure and the longer red solid line in the left hand figure). The consumers in the importing bidding zone will now have to pay a local power price that includes the cost of losses, and a price difference between the two bidding area will occur (P^{M2}-P^{E2}), even without congestion. The magnitude of the price changes depicted in Figure 3 will depend on price-elasticities in the two bidding zones. The price difference between the two markets is a reflection of the marginal cost of energy loss on the transmission line, and will not cause a congestion income to appear (in uncongested situations). However, the price changes will cause the benefit of trade to be smaller than before, as illustrated by the two grey triangles in Figure 3 being smaller than in Figure 2. Thus, implementing implicit grid losses in uncongested situations will generate a welfare loss in the formal PX market.

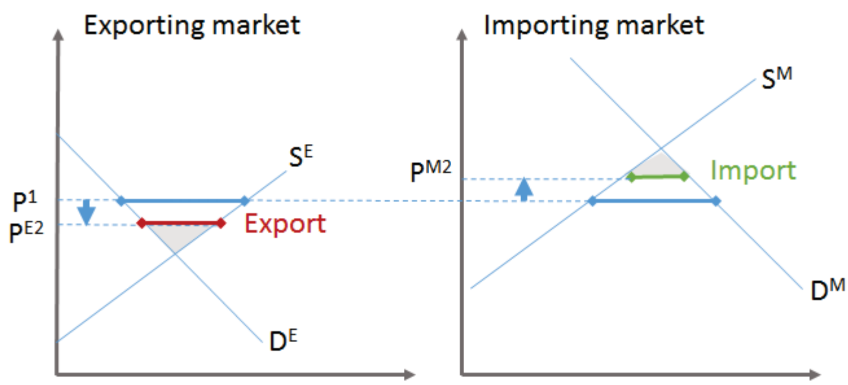


Figure 3. Implicit grid losses in an uncongested situation.

3.2 Impact in congested situations

Figure 4 illustrates the effects of implementing implicit grid losses in constrained situations when there is an initial price difference between the bidding zones due to limited transmission capacity.

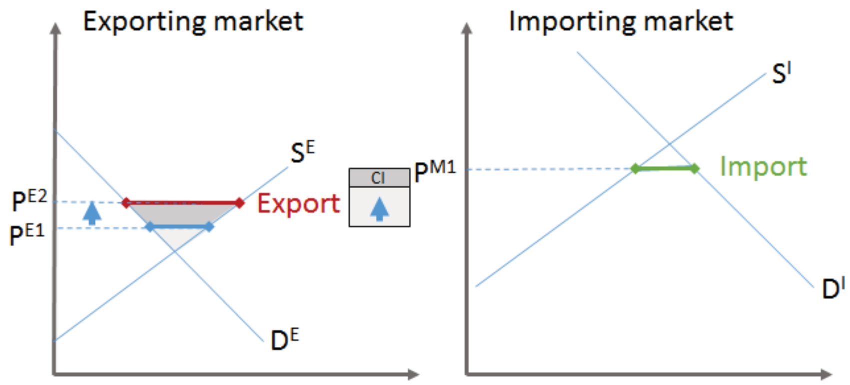


Figure 4. Implementing implicit grid losses in a congested situation.

As in the uncongested scenario, when implicit grid losses is implemented, less energy is received by the consumers in the importing bidding zone than is sent from the exporting bidding zone. However, as the marginal willingness to pay is now higher in the importing bidding zone than in the exporting bidding zone, and in order to supply the higher paying importing market, the volume bought in the exporting market has to increase in order to serve both the received energy and the induced losses. This causes the prices in the exporting market to rise without any price movements in the importing bidding zone[3]. Thus, the price difference between bidding zones and the congestion income will decrease (as illustrated in Figure 4), specifically the congestion income will drop by more than the reduction in price difference due to the marginal cost of losses that has to be covered.

Due to the price change, the sum of producer and consumer income in the exporting market will increase (as illustrated by the grey shaded area in the left hand figure). The congestion income will however decrease more than this. In sum, the implementation of implicit grid losses will generate a welfare decrease in congested situations as well as in uncongested situations.

3.3 Remarks on the theoretical discussion

As a final remark to the discussion above, some general observations on implementing implicit grid losses in the market simulations may be drawn:

[3] That is, until prices become equal, turning into an uncongested situation.

* In uncongested situations, prices will increase in the importing market and/or decrease in the exporting market without generating a congestion income.
* In congested situations, there will, (based on our simulations,) be an increase in the price in the exporting market. There will hence be a decrease in congestion income in congested situations. Without the simplifications explained in the introduction of the chapter, there would however not be a change in congestion income. The end result would be the same.

The sum of consumer and producer surplus will be negative, while providing a loss for consumers and a gain for producers.

When implicit losses are introduced on DC-interconnectors, transportation through the DC-interconnectors will be more expensive and more power will be transmitted through the AC-grid. Thus, DC losses will decrease while AC losses will increase. These are external cost factors which must be regarded together with effects on market welfare in order to decide if implementation of implicit losses generates a positive or negative effect on the total economic welfare. Table 2 sums up what we have found from the theoretical analysis.

		Uncongested situations	Congested situations	Sum
1	**Changes in economic market welfare (MW)**	-	-	-
1a	*Changes to consumer surplus (CS)*	?	-	?
1b	*Changes to producer surplus (PS)*	?	+	?
1c	*Changes to congestion income (CI)*	0	-	-
2	**Changes to AC loss costs (AC losses)**	+	+	+
3	**Changes to DC loss costs (DC losses)**	-	-	-
4	**Changes to total welfare (MW - AC losses - DC losses)**	?	?	?

Table 2. ***Theoretically expected welfare changes of implementing implicit grid losses.***
Please note: ? = unknown, 0 = no effect, + = increase and - = decrease.

The numerical results from the simulations are examined in chapter 7. These results will depend on the number of congested versus uncongested situations and the magnitude of the changes to the individual welfare effects. In the simulations, the total effects on market welfare in the energy market are also compared to the (external) induced changes in the cost of AC and DC losses. The next chapter provides an explanation on how the numerical costs associated with AC-grid losses in the simulations have been derived.

4. Methodology

The study has been carried out using three approaches;

1. A theoretical discussion of implicit grid losses,
2. numerical simulations of market effects in the day-ahead market, and
3. a statistical methodology for the assessment of the physical AC-grid losses.

The theoretical market analysis, which is described and elaborated in Chapter 3, aims at explaining which market effects to expect in terms of price movements, changes to congestion income and consumer and producer surpluses in the numerical simulations. The theoretical market analysis is further used when assessing the results from the numerical simulations.

The numerical simulations of market effects in the day-ahead market have been carried out using several scenarios for implementing implicit grid losses on different DC-interconnectors. Ten scenarios have been simulated, implementing implicit grid losses to a varying extent. The simulations have been done in the PX simulation facility, implying that real market bids/order books have been used to simulate market equilibriums within the market coupling algorithm (Euphemia). The simulated time period is 16 months, where hourly time resolution has been used, starting in February 2014 and ending in May 2015. The chosen period covers the period where the Multi-Regional Price Coupling (MRC) has been in place and implicit grid losses has not yet been implemented on the NorNed cable, but on the Britned, IFA and Baltic cable. NordBalt cable was not in use yet. Only a few days are missing in the simulated time span due to non-convergences at the simulation facility[4]. The results presented in this report are 12 month averages of the 16 month period. The aim of the calculations is to assess changes in producer and consumer surplus along with congestion income.

The AC losses are calculated by statistical derived formulas, presented in chapter 5, which are then applied on flows in the simulated results. The statistical models are developed by each of the four TSOs and are simplifications of the actual losses on the AC-grid. Due to the manageable nature of the DC-interconnectors, no statistical model is needed as the physical DC losses follows directly from the simulation results and the applied loss factors on each DC-interconnector.

In the end, the total welfare economic results are an aggregate of the numerical simulation results from the day-ahead market, the physical grid loss calculations and the statistical methodology for the assessment of the losses on the AC-grid.

4.1 Scenarios

Ten scenarios have been agreed to form the basis for the analyses. All scenarios are simulated for the full 16 month time period, each distinguished by implicit losses implemented on different DC-

[4] The missing days are: 30/-2014, 13/8-2014, 26/10-2014, 6/11-2014 and 29/3-2015

interconnectors, or set of DC-interconnectors. The following DC-interconnectors have been considered in the scenarios:

a. NorNed (NO2-Netherlands)
b. Skagerrak (DK1-NO2)
c. KontiSkan (DK1-SE3)
d. SwePol (SE4- Poland)
e. Baltic (SE4-Germany)
f. Kontek (DK2-Germany)
g. Great-Belt (DK1-DK2)
h. Estlink (FI-Estonia)
i. FennoSkan (FI-SE3)

The ten simulated scenarios, illustrated in Table 3 are:

#01. No implicit losses on any DC-interconnector
#02. Reference case – Simulation with implicit losses on NorNed and Baltic cable as is the case today.
#03. Implicit losses with actual[5] loss factor on all interconnectors except FennoSkan
#04. Implicit losses with equal[6] loss factors on Great-Belt, Skagerrak, KontiSkan and Baltic interconnectors and actual loss factors on all other interconnectors except FennoSkan
#05. Implicit losses with actual loss factors on all interconnectors
#06. Implicit losses on NorNed, Baltic and Skagerrak interconnectors
#07. Implicit losses on NorNed, Baltic, Skagerrak and KontiSkan interconnectors
#08. Implicit losses with actual loss factors on NorNed and Baltic and equal loss factors on Skagerrak and KontiSkan interconnectors
#09. Implicit losses with actual loss factors on NorNed and Baltic and equal loss factors on Skagerrak, KontiSkan and the Great-Belt interconnectors
#10. Implicit losses with equal loss factors on all interconnectors except FennoSkan

[5] Individual loss factors in the allocation on the respective DC cables – It is assumed that the actual loss factor reflects the losses on the interconnector.

[6] Equal loss factor means a harmonised loss factor across the DC cables.

	#01	#02	#03	#04	#05	#06	#07	#08	#09	#10
DK1>DK2			1.5 %	2.5%	1.5 %				2.5 %	2.5 %
DK1>NO2			3.8 %	2.5 %	3.8 %	3.8 %	3.8 %	2.5 %	2.5 %	2.5 %
DK1>SE3			2.6 %	2.5 %	2.6 %		2.6 %	2.5 %	2.5 %	2.5 %
DK2>DE			2.5 %	2.5 %	2.5 %					2.5 %
EE>FI			5.1 %	5.1 %	5.1 %					2.5 %
FI>SE3					2.4 %					
NL>NO2		3.2 %	3.2 %	3.2 %	3.2 %	3.2 %	3.2 %	3.2 %	3.2 %	2.5 %
PL>SE4			2.6 %	2.6 %	2.6 %					2.5 %
SE4>DE		2.4 %	2.4 %	2.5 %	2.4 %	2.4 %	2.4 %	2.4 %	2.4 %	2.5 %

Table 3. Overview of the scenarios and applied loss factors.

The purpose of the ten scenarios is to be able to answer the following questions:

The effect under the current setup – Implicit losses on the NorNed and Baltic cables:

- What is the impact of the current implemented loss factors (NorNed and Baltic cable)? #01 vs. #02

The effect of loss factors on all DC-interconnectors:

- What is the impact of loss factors on all interconnectors? #03 vs. #02
- Is the difference in loss factors a significant driver for the change in the AC losses - What is the impact of having equal loss factors on all interconnectors to Germany? #04 vs. #03
- What is the impact of having equal loss factors on all interconnectors except FennoSkan? #10 vs. #03
- What is the impact of loss factor on the FennoSkan interconnector? #05 vs. #03

The effect of loss factors on all interconnectors to and from DK1:

- What is the impact of implementing loss factor on Skagerrak interconnector? #06 vs. #02
- What is the impact of implementing loss factor on Skagerrak and KontiSkan interconnector? #07 vs. #06
- Is the difference in loss factors a significant driver for the change in the AC losses – What is the impact of implementing equal loss factor on Skagerrak and KontiSkan interconnector? #08 vs. #06
- What is the impact of having loss factors on the Great-Belt interconnector? #09 vs. #08
- Is the difference in loss factors a significant driver for the change in the AC losses – What is the impact of implementing equal loss factor on all interconnectors to and from DK1? #09 vs. #02

5. Methodology for calculating the AC losses

The calculations of AC losses are based on statistical factors related to flows on the bidding zone borders. Thus, the calculation and loss factors vary between the Nordic countries and borders. The methodology for calculating the AC losses is based on loss functions estimated by statistical analysis using linear regression. It has been shown that assuming a straight line to describe the loss function is a simplification that sometimes provides a statistically bad fit, especially for the extreme points in the statistical population. This simplification implies that some of the absolute values of the losses are misleading, however still providing a good estimate for the difference between the simulations for each hour[7]. The derived models used for the AC loss calculations are the following:

5.1 Norwegian AC losses

AC losses in NO in an hour:

$$ACloss_{sim,i} = \frac{1}{27}(F_{sim,i} - 1160)$$

Where:

- F: sum of absolute value of flow on all NO borders

Cost of AC loss in NO for all hours:

$$cost_{sim} = \sum_{i \in H} P_{sim,i} \, ACloss_{sim,i}$$

Where:

- H: all hours simulated
- P: average price in all NO areas
- sim: simulations

The Norwegian AC losses are calculated for the whole country and not per bidding zone like the other market welfare results.

5.2 Danish AC losses

Impact on AC losses (calculated for each hour):

$$PlossDK1 = a * Load_{DK1}{}^2 + b * GEN_{DK1}{}^2 + c * P_{DK1-DE}{}^2 + d * P_{DK1-DK2}{}^2 + e * P_{DK1-NO2}{}^2 + f * P_{DK1-SE3}{}^2 + k$$

$$PlossDK2 = a * Load_{DK2}{}^2 + b * GEN_{DK2}{}^2 + c * P_{DK2-DE}{}^2 + d * P_{DK1-DK2}{}^2 + e * P_{DK2-SE4}{}^2 + k$$

Where:

[7] See annex 9.9.

For PlossDK1:

- GEN_{DK1}: Generation in DK1
- $Load_{DK1}$: Load in DK1
- $P_{X\text{-}Y}$: The flow between X and Y
- a: 6.8274E-08
- b: 8.33358E-07
- c: 6.04492E-06
- d: 1.99238E-05
- e: 4.17115E-06
- f: 1.0431E-05
- k: 21.52806

For PlossDK2:

- GEN_{DK2}: Generation in DK2
- $Load_{DK2}$: Load in DK2
- $P_{X\text{-}Y}$: The flow between X and Y
- a: 0
- b: 8.97019E-06
- c: 1.62575E-06
- d: 2.6979E-05
- e: 7.62011E-06
- k: 3.197391431

Cost of AC losses in Denmark:

$$cost_{sim} = \sum_{a \in [DK1,DK2]} \sum_{i \in H} P_{sim,a,i}\, ACloss_{sim,a,i}$$

Where:

- H: all hours simulated
- P: price
- sim: simulation
- a: area (DK1, DK2)
- ACloss: calculated AC losses

5.3 Finnish AC losses

Impact on AC losses in FI in an hour:

$$ACloss_{sim,i} = 0.01671327 f_{FI-RU,sim,i} + 0.01587131 f_{FI-EE,sim,i} - 0.04367261 f_{FI-SE1,sim,i} - 0.01238245 f_{FI-SE3,sim,i} + 81$$

Where:

- f: flow
- FI-**: border *from* area FI *to* area **

Impact on cost of AC loss in FI for all hours:

$$cost = \sum_{i \in H} P_{sim,i} \, ACloss_{sim,i}$$

Where:

- H: all hours simulated
- P: hourly price in Finland
- sim: simulation

The coefficient of determination R^2 of the linear regression model between the Finnish AC losses and the cross-border flows is lower than 0.5, which is very low. This means the AC losses are not highly correlated to the cross border flows and there are other factors that affect the AC losses, and therefore the linear approximation is not very good. This is however a model that can be fitted to the results of the market coupling algorithm (Euphemia) used in this analysis. One should keep in mind that because the estimations of the cost of AC losses in Finland are not very accurate, which affects the reliability of the results.

5.4 Swedish AC losses

AC losses in area *a* in hour *i* for simulation *sim*:

$$ACloss_{sim,a,i} = \frac{1}{K_a}(F_{sim,a,i} - L_a)$$

Where:

- F: sum of absolute value of flow on all area borders
- K: area specific loss factors [SE1: 24, SE2: 26, SE3: 60, SE4: 99]
- L: area specific fixed factor [SE1: 1024, SE2: 1140, SE3: 763, SE4: 873]

Cost of AC loss in SE for all hours:

$$cost_{sim} = \sum_{a \in [SE1,SE2,SE3,SE4]} \sum_{i \in H} P_{sim,a,i} \, ACloss_{\,sim,a,i}$$

Where:

- H: all hours simulated
- P: average price in SE areas
- sim, ref: simulation with loss factors, and reference simulation
- a: area (SE1, SE2, SE3, SE4)
- ACloss: calculated AC looses

The Swedish method is primarily developed to be used for loss calculations in the southern parts of Sweden. The following example illustrates why the method is not as well suited for northern Sweden:

Assuming implicit losses is implemented on the FennoSkan link, the flow SE3>FI is reduced and the flow SE3>SE2>SE1>FI is increased. In case the change in flows affects the absolute value in the same direction, 1 MW less on FennoSkan would imply the following losses in the northern path through the AC grid:

Losses in SE3: $1\ MW * \frac{1}{60} = 1.7\ \%$

SE2 (changed flow on two borders): $2\ MW * \frac{1}{26} = 7.7\ \%$

SE1 (changed flow on two borders): $2\ MW * \frac{1}{24} = 8.3\ \%$

Thus, the effect from a changed flow of 1 MW yields a change in AC losses in Sweden of almost 18 pct.

As mentioned above, the method is based on linear regression and a loss coefficient between flow and losses. Using linear regression assuming a straight line representing the losses is sometimes not the best fit, especially not for the extreme points. For example, in cases where the sum of the flows on the borders in a given area is very small they converge to zero instead of following the assumed straight line. It is therefore important to keep in mind that it is the difference between the simulations for each hour that is most relevant and not the single loss figures.

6. Calculations of welfare economic effects

The total welfare economic effects of implementing implicit losses are the sum of Market welfare changes, the loss cost changes of the DC-interconnectors and the loss cost changes in the AC-grid. The changes in each scenario are calculated compared to the reference scenario (#02).

The Market welfare (ΔM) is the sum of changes in Producer surplus (ΔPS), the changes in Consumer surplus (ΔCS) and the changes in Congestion income (ΔCI), all calculated as outcome from the market coupling algorithm (Euphemia). Congestion income is evaluated at the receiving end at the relevant price difference.

$$\Delta \mathbf{M} = \Delta \mathbf{PS} + \Delta \mathbf{CS} + \Delta \mathbf{CI}$$

The changes in AC loss costs (ΔAC), which are generated externally to the market coupling algorithm (Euphemia), are the calculated change in AC losses evaluated at the price in the area where the losses occur. Thus, the Norwegian losses are evaluated at the average Norwegian area prices, the Swedish loss costs are evaluated at the average Swedish area prices, the Danish at the average Danish area prices, and the Finnish losses at the Finnish area price[8].

The DC loss costs are also generated externally to the market coupling algorithm (Euphemia), and are evaluated at the price in the receiving end of the interconnector as the lost energy is perceived as "received" in the market coupling algorithm (Euphemia), and as such provides a consumer surplus that will not materialize in reality. The change in the external losses costs are denoted ΔDC.

Thus, **the total welfare economic benefit (ΔW)** of implementing implicit grid losses is:

$$\Delta \mathbf{W} = \Delta \mathbf{M} - \Delta \mathbf{AC} - \Delta \mathbf{DC}$$

In this report, the economic welfare results have been calculated taking into account only the Nordic countries and the interconnectors connected to the Nordic bidding zones. The impacts to the bidding zones that are connected to the Nordics are not in the scope of this report. A more comprehensive analysis would include the economic welfare calculations for the whole NWE region.

8 The average prices are used because we do not know the actual geographical distribution of the AC flows for each national loss calculation.

7. Simulation results of implicit grid losses

The PX simulation facility has been utilized for simulating implicit grid losses. Thus, real bids have been used to simulate market equilibriums within the market coupling algorithm (Euphemia) over a period of 16 months between February 2014 and May 2015. All simulations are done with hourly time resolution. Ten scenarios, which are summarized in Table 3, have been analysed.

7.1 Aggregated Nordic results

The changes in Market welfare in the simulated scenarios are displayed in Figure 5 and Table 4. The changes are all calculated related to simulation #02, which is the reference case. The short solid black lines are the Market welfare, which is the sum of the Congestion income, Consumer surplus and Producer surplus (see Chapter 6), corresponding to the first row (1) in Table 2. The red and green bars and the blue line are the individual components in the Market welfare, which correspond to line 1a, 1b and 1c in Table 2.

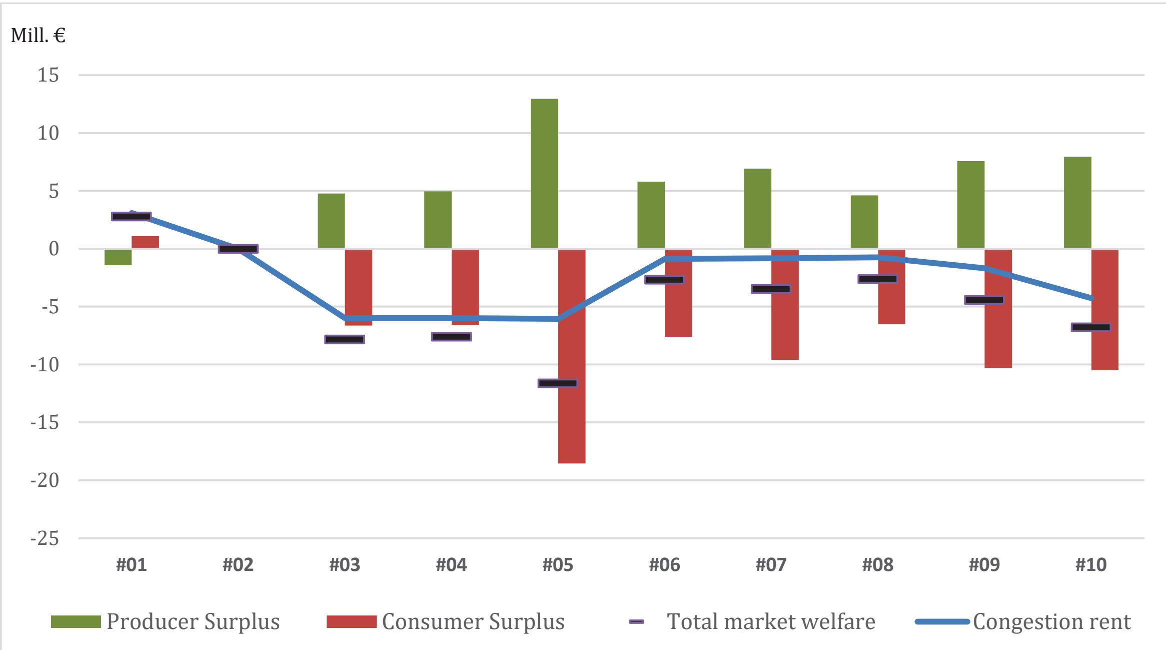


Figure 5. Changes in Nordic Market welfare, Mill €.

The simulation results are in line with what the theoretical results indicated. When implicit grid losses are implemented on the DC-interconnectors in the Nordics, Market welfare decreases, Consumer surplus decreases, while Producer surplus increases. The simulations also reveal that the Congestion income in all scenarios except in scenario #01 decreases.

In scenario #01 where the implicit loss function is removed from all DC-interconnectors, including NorNed and Baltic cable, the exact opposite of all other scenarios happens (as would be expected).

Except for the case where implicit grid losses are implemented on FennoSkan, in scenario #05, the implementation of implicit losses on DC-interconnectors tends to strengthen the observed results that the Market welfare decreases. Also the Congestion income seems to be confirmed as to decrease. The effect on Congestion income however, depends on the simulation period, and could vary in other time periods.

Scenario	Producer surplus (ΔPS) (Green bar)	Consumer surplus (ΔCS) (red bar)	Market Welfare (ΔM) (solid black line)	Congestion Income (ΔCI) (blue line)
#01	-1.4	1.1	2.8	3.1
#02	-	-	-	-
#03	4.8	-6.6	-7.8	-6.0
#04	5.0	-6.6	-7.6	-6.0
#05	12.9	-18.5	-11.6	-6.1
#06	5.8	-7.6	-2.7	-0.9
#07	6.9	-9.6	-3.5	-0.8
#08	4.6	-6.5	-2.6	-0.7
#09	7.6	-10.3	-4.4	-1.7
#10	7.9	-10.5	-6.8	-4.3

Table 4. Changes in Nordic Market welfare, Mill €.

Market welfare	Consumer surplus	Producer surplus	Congestion income
↓	↓	↑	↓

Table 5. Simulation results for scenario #02 - #10.

Market welfare	Consumer surplus	Producer surplus	Congestion income
↑	↑	↓	↑

Table 6. Simulation results for scenario #01 (No implicit grid losses in the Nordic).

As discussed in chapter 3, the implementation of implicit grid losses will influence the magnitude and distribution of grid losses on both the AC-grid and the DC-interconnectors. The calculated change in cost of grid losses for each scenario is displayed in Figure 6. The figure corresponds to second and third row (2 and 3) in Table 2. The changes are again all calculated with simulation #02 as the reference case.

The External loss costs on the DC-interconnectors are, as seen in Table 7, reduced significantly when implicit grid losses are implemented. Thus, the reduction is larger when more DC-interconnectors are managed by implicit grid losses. The opposite is true, as expected, for the AC-grid. More of the electricity is transported through the AC-grid as the transportation of electricity through the DC-interconnectors becomes more costly. The effect on the External loss costs of DC-interconnectors is however much larger than the effect on the loss costs of AC-grid, mainly due to the higher price differences between the areas that are connected via DC-interconnectors.

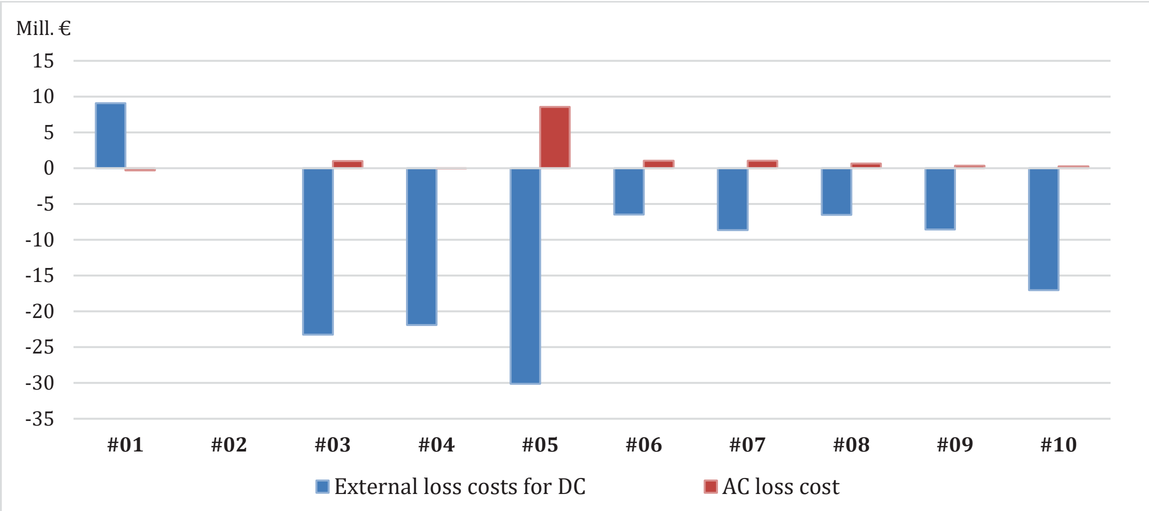


Figure 6. Calculated changes in Nordic loss costs for all simulations, Mill €.

Scenario	External loss costs for DC (ΔDC) (Blue bar)	AC loss costs (ΔAC) (red bar)
#01	9.1	-0.31
#02	0.0	0.00
#03	-23.3	1.02
#04	-21.9	-0.01
#05	-30.1	8.55
#06	-6.5	1.06
#07	-8.6	1.03
#08	-6.5	0.66
#09	-8.6	0.33
#10	-17.0	0.28

Table 7. Calculated changes in Nordic loss costs for all simulations, Mill €.

There is one instant to note in particular. When implicit losses are implemented on the FennoSkan interconnector, in scenario #05, the power flow that is displaced from the DC-interconnector, is rather directed through the Swedish grid towards the north, and further down south into Finland as illustrated in Figure 7.

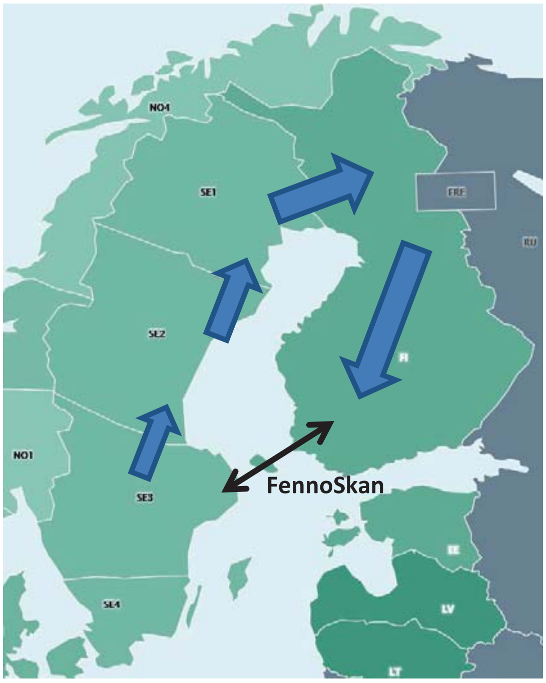


Figure 7. Alternative path for power flowing on FennoSkan.

This causes the physical AC losses to increase nearly four times compared to the transmission losses on the FennoSkan interconnector. Thus, implementing implicit losses on FennoSkan causes the AC loss costs to increase much more severely than any other Nordic DC-interconnector.

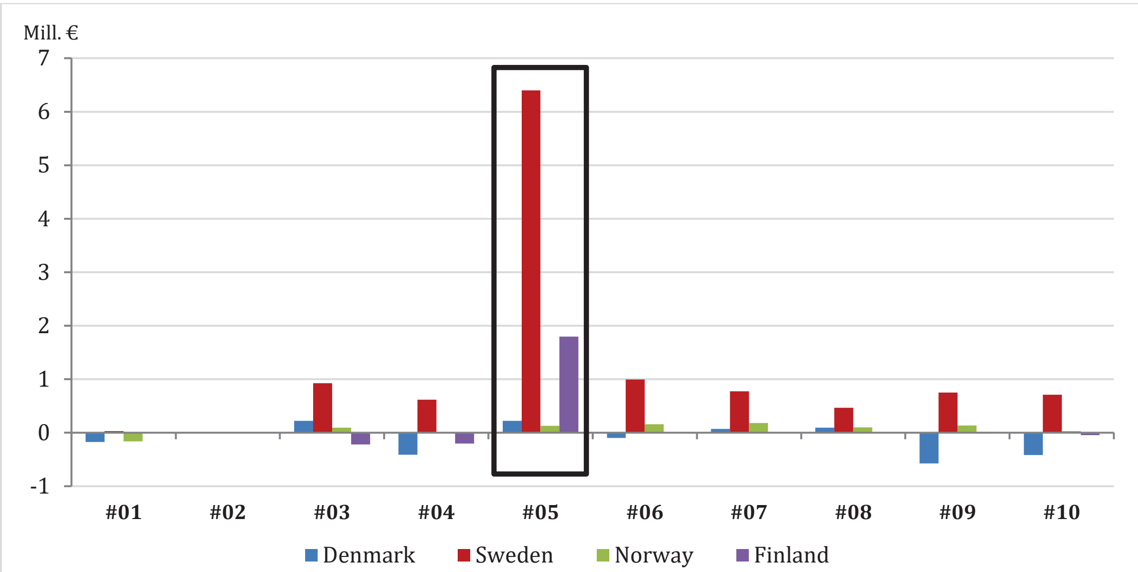


Figure 8. Loss costs for AC-grid for each scenario and each country. Scenario #05 shows the effect of implementing implicit losses on FennoSkan, Mill. €. See annex 9.4 for table with numbers.

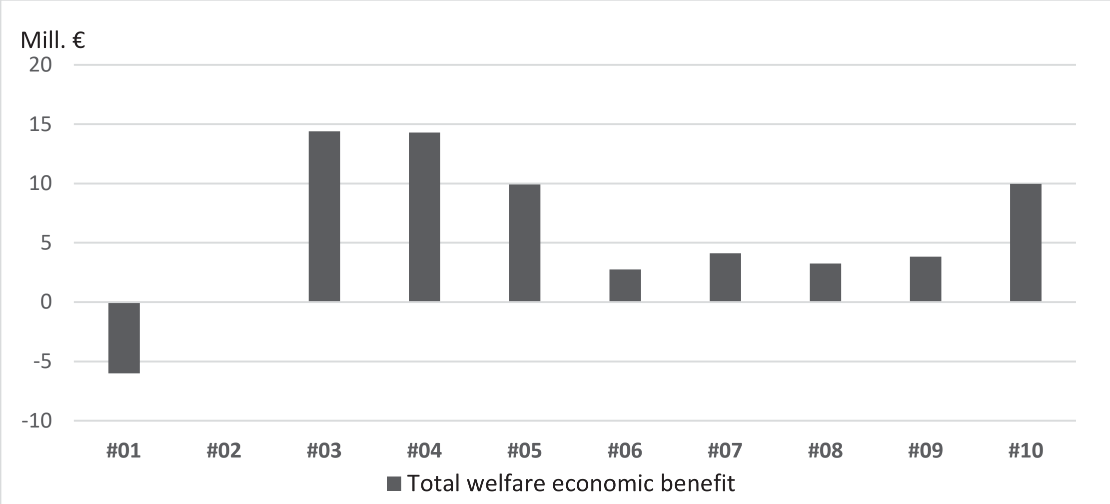


Figure 9. Nordic Total welfare economic benefit of the implicit losses, Mill €. See annex 9.1 for table with numbers.

The Total welfare economic benefits (Chapter 6) of the simulations are displayed in Figure 9. The figure corresponds to fourth row (4) in Table 2.

All simulations with implicit grid losses display a positive Total welfare economic benefit. In general, with implicit losses implemented on more DC-interconnectors, the benefit increases. One exception, however, is FennoSkan. When FennoSkan is included on top of the other DC-interconnectors, the Total welfare economic benefit decreases (Scenario #05 vs. Scenario #03). This is due to the severe increase in the AC loss costs from the Swedish and Finnish grid when power is directed towards the northern connection between Sweden and Finland. Thus, implementing implicit losses on FennoSkan causes a Total welfare economic loss for the Nordics.

	#03	#05	Total welfare loss
Total Welfare	14.4	9.9	4.5

Table 8. Total welfare loss when implementing implicit grid losses on FennoSkan, Mill €.

7.2 Results for the individual countries

The changes in Market welfare for each individual Nordic country are illustrated in Figure 10. Generally, the results for the individual countries follow the results observed for the Nordics in total. There is however some discrepancies from the general picture in scenario #06 - #08 concerning Denmark and #9 concerning Sweden where we observe a positive market welfare gain.

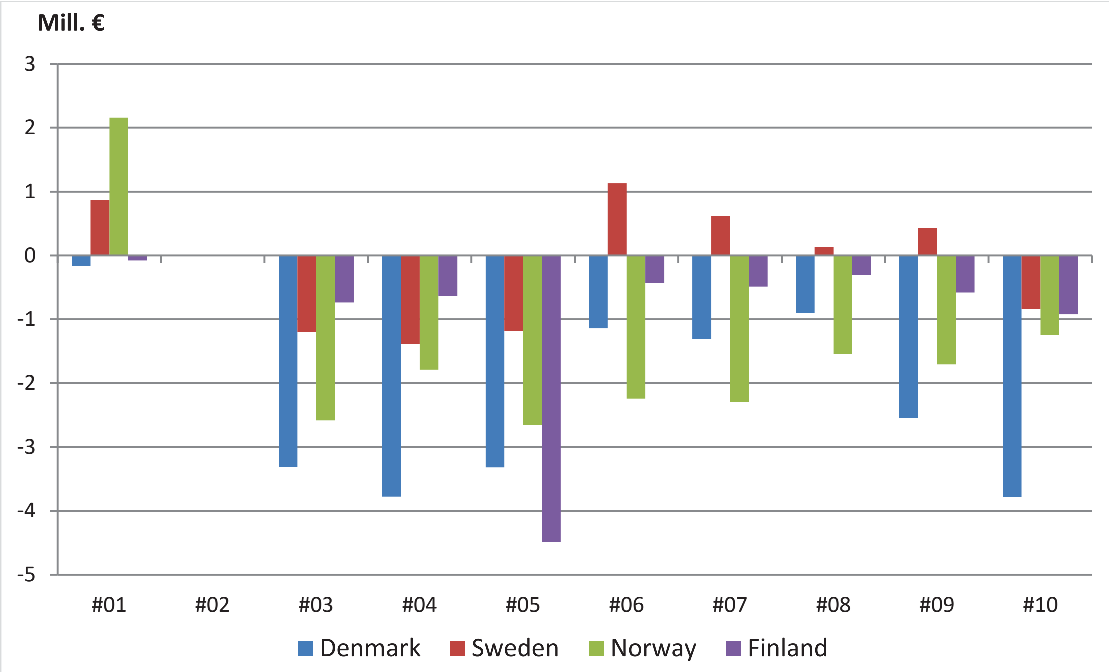


Figure 10. Changes in Market welfare for each Nordic country, Mill. €. See annex 9.2 for table with values.

Scenarios #06, #7, #8 and #09 are different variations of implementing implicit losses on the Skagerrak, KontiSkan and Great-Belt interconnectors. These scenarios change the cost of southern electricity trades on the Nordic DC-interconnectors, thus, the trade patterns in the same area change. Particularly, implementing implicit losses on the Skagerrak connection (in scenario #6) benefits Sweden due to the trades between Denmark and Sweden now being preferred over trades between Denmark and Norway (due to the loss factor on Skagerrak). Thus, the market welfare increases in Sweden in scenario #6. This effect gradually decreases as implicit losses are also implemented on the Kontiskan and the Great-Belt interconnectors in scenarios #7, #8 and #9 (scenario #8 is a variation of #7 with lower loss factors).

The changes in External loss costs for the DC-interconnectors and AC-grid loss costs for each individual Nordic country induced by the market behaviour caused by implicit losses being implemented are shown in Figure 11 and Figure 8. As expected, the External losses costs for the DC-interconnectors is decreasing in all scenarios except for #01.

As presented in Figure 8 above, the loss costs of AC-grid in general increases, except some small decreases for Denmark in the scenarios #04, #06, #09 and #10. Also Finland experiences a decrease in the loss costs for AC-grid in scenario, #03 and 04, with a change in loss costs at -0.2 Mill. €. And Norway also experiences a change in loss costs in scenario #01 at -0.2 Mill. €

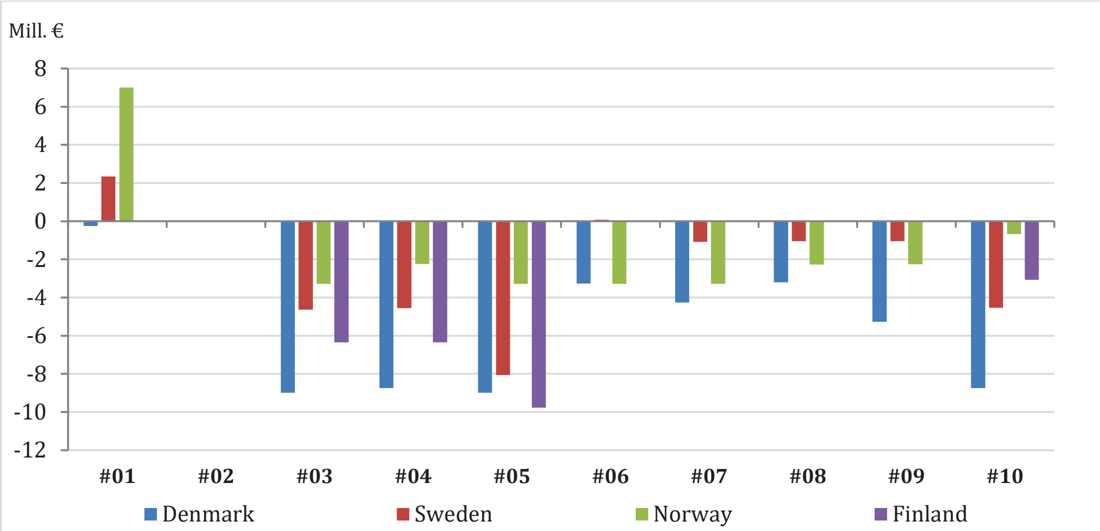


***Figure 11.** Changes in External losses costs for DC-interconnectors for each Nordic country, Mill. €. See annex 9.3 for table with numbers.*

The change in Total welfare economic benefit for each country is derived by merging the results presented in Figure 8, Figure 10 and Figure 11. The result is presented in Figure 12. The general results indicate that implementing implicit losses on the DC-interconnectors provide benefits for all Nordic countries.

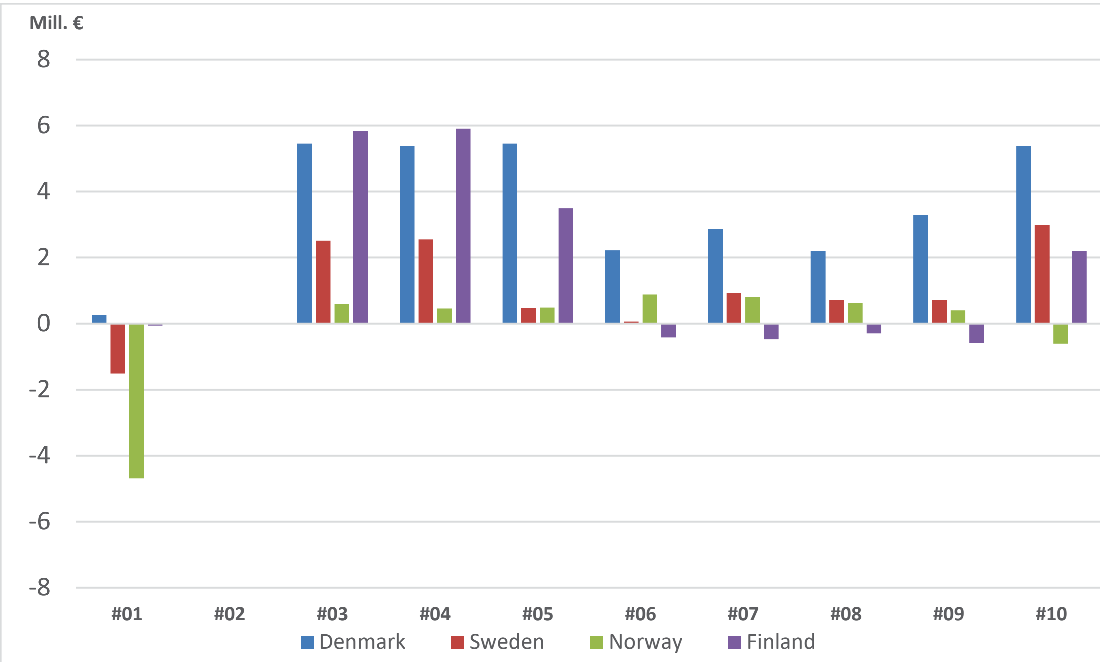


***Figure 12.** Total welfare economic benefit for each Nordic county, Mill. €.*

However, there are some deviations from the general indication. Finland experience small losses in scenario #6, #7 and #8. In these scenarios, there are very little impact on the Finnish grid loss costs, in particular no reduction in DC loss costs. Thus, the negative impact from the day-ahead market outcome, meaning the loss in market welfare, prevails. Similarly, this holds for Norway in scenario #10. Scenario #10, however, provides positive total welfare economic benefit in Finland due to the reduction in DC loss costs that are introduced by the implementation of implicit loss costs on Estlink.

7.3 Price convergence

Since implementing implicit losses will prohibit situations with equal price in both the import and exporting bidding zone, one would expect that the number of hours where several bidding zones have a similar price will drop as implicit losses are implemented on more DC-interconnectors. In Figure 13 we have counted the number of unique prices (prices that differ from all other prices) in each hour in all the scenarios. Each column represents one of the scenarios, and a light colour indicate hours with few different prices in the Nordics, while a dark colour indicates hours with many different prices[9].

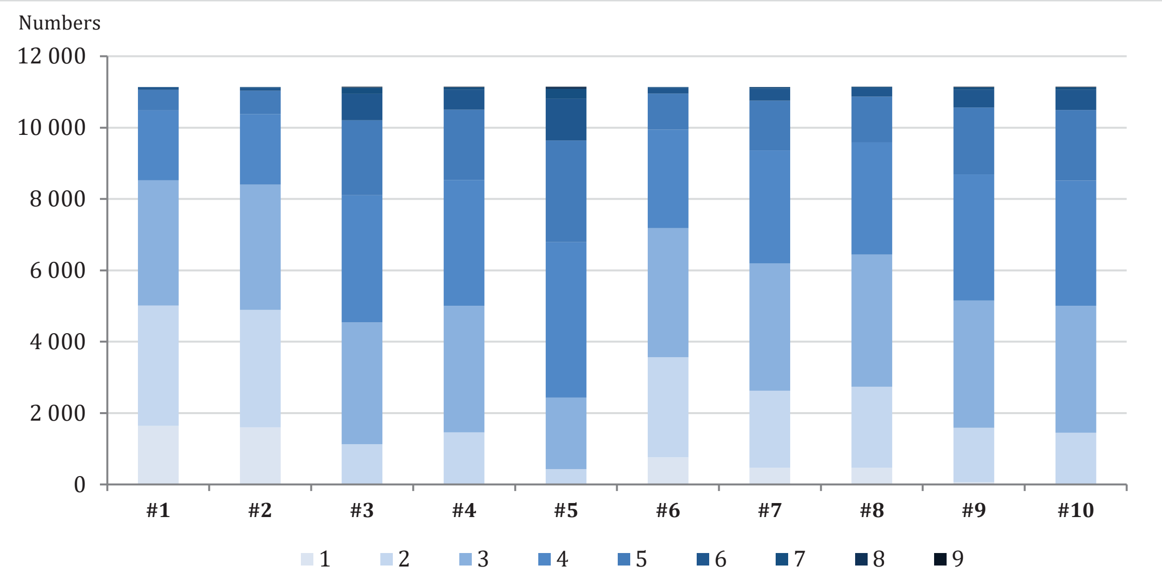


Figure 13. The number of different prices in the Nordics in the scenarios.

What is clear from the figure is that the scenario #05 with implicit losses on all interconnectors is the scenario with most hours with different prices between the areas in the Nordics. In scenario #05, there are no hours with full price convergence (the same price in all bidding zones), and it is the scenario with most hours with five or more different prices. We might also note that scenario

[9] Few = 1 different price, many = 9 different prices

#01 and #02 are the ones with most hours with full price convergence, where we never find more than seven different prices, and in general the scenarios with fewest number of different prices.

7.4 AC flow effect illustrations

As observed in the Total welfare economic benefit results, the changes in the loss costs for the AC-grid is quite small and far outnumbered by the changes in the External loss costs for the DC-interconnectors, except for scenario #05 where implicit losses on FennoSkan causes a large AC flow through the Swedish grid in the north. The loss costs are however an aggregate of a physical change in flow, and a price difference. Thus, the result could in theory be related to a considerable change in the physical AC flow at a small price difference.

In order to investigate this, we have calculated the flow in all scenarios for the AC-interconnectors, see annex 9.7. The AC-interconnectors we have looked further into are:

- DK1 – DE
- DK2 – SE4
- SE3 – SE4
- NO1 – SE3
- NO3 – SE2
- NO4 – SE2
- NO4 – SE1
- SE2 – SE3
- SE1 – FI

In Figure 14, the changes in the flows on the AC-interconnectors compared to scenario #02 are shown for all scenarios.

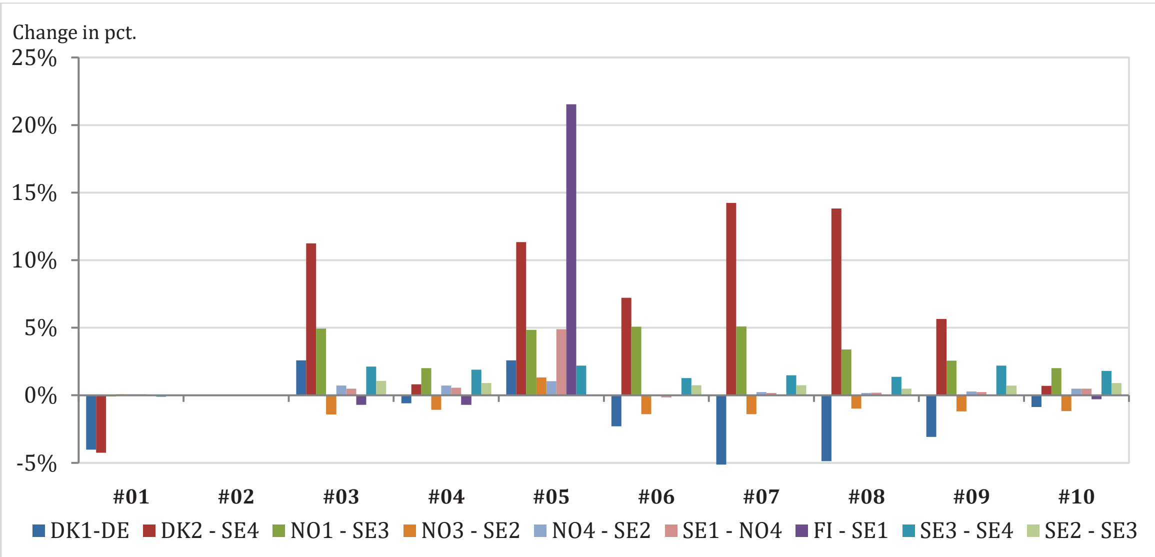


Figure 14. The change in flows on the AC-interconnectors compared to the scenario #02.

It can be seen from the figure that the effects are most significant for the AC-interconnectors FI-SE1, DK2-SE4, SE1-SE2, SE2-SE3, DK1-DE and NO1-SE3. All other interconnectors have a change of less than 5 pct.

Figure 15 and Figure 16 shows the results for some important AC-interconnectors in terms of the use of the capacity given to the day-ahead market. The figures show the fraction of time, in the 16 months simulations period, where the flow on the AC-interconnectors is above a threshold compared to the provided day-ahead capacity for each of the simulated scenarios. The threshold is 90 pct. of the day-ahead capacity in Figure 15, and 99 pct. of the day-ahead capacity in Figure 16.

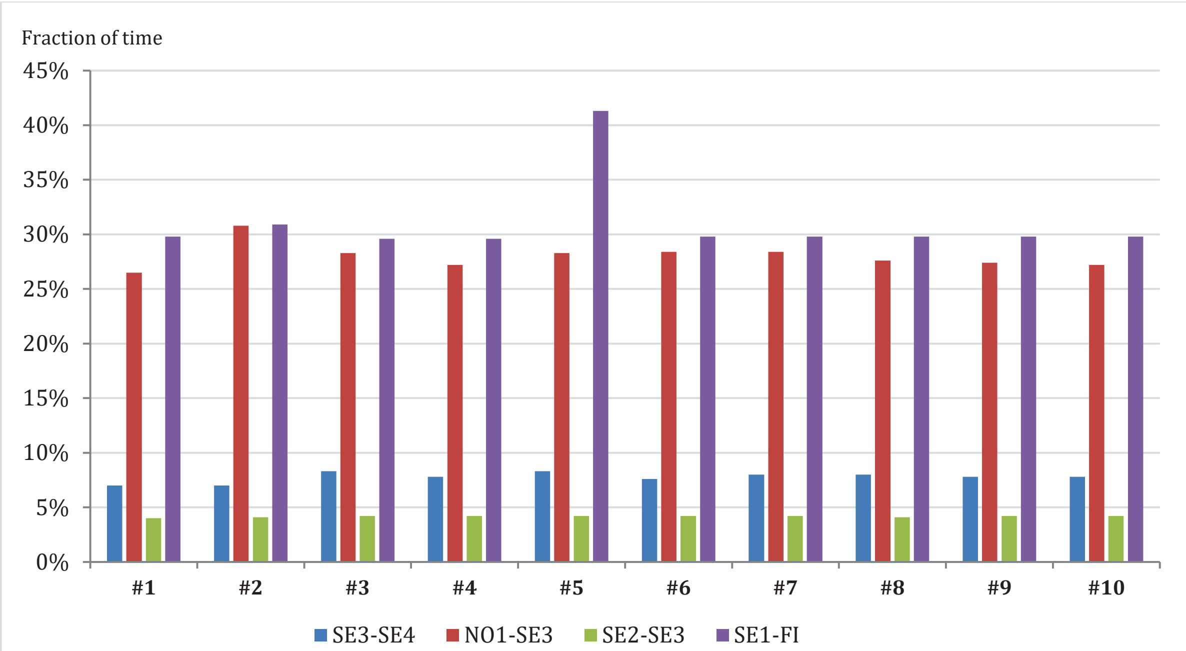


Figure 15. The fraction of time with a flow on AC-interconnectors above 90% of the provided day-ahead capacity.

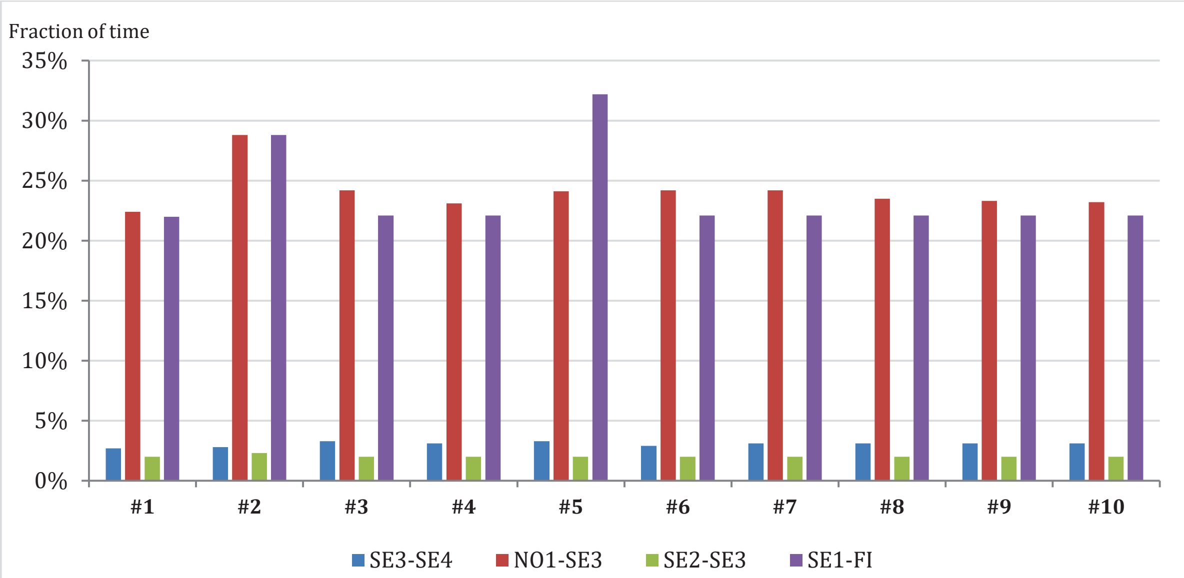


Figure 16. The fraction of time with a flow on AC-interconnectors above 99% of the provided day-ahead capacity.

Except for scenario #05, it is thus clear from the calculations illustrated in the figures above that the influence on the flow on the AC-interconnectors when implementing implicit grid losses are rather small. This is obvious from the small variations in AC-interconnector flow between the different scenarios.

If we look a bit more into the AC-interconnectors FI-SE1, DK2-SE4, SE1-SE2, SE2-SE3, DK1-DE and NO1-SE3, we can start with looking at the change in maximum flows on the interconnectors.

As it can be seen from the table, there are only changes to the maximum flows on a few AC-interconnectors. The flow on the DK1-DE interconnectors increases for the scenarios #03, #04, #05 and #10, when we implement implicit grid losses on the Great-Belt and Kontek interconnector. There is also a change in the flows for the SE2-SE3 interconnector for all scenarios except for scenario #06.

Scenario	FI-SE1	DK2-SE4	SE1-SE2	SE2-SE3	DK1-DE	NO1-SE3
#01	-	-	-	0.29%	-	-
#02	-	-	-	-	-	-
#03	-	-	-	-0.32%	4.41%	-
#04	-	-	-	-0.34%	4.36%	-
#05	-	-	3.54%	-0.32%	4.41%	-
#06	-	-	-	-	-	-
#07	-	-	-	-0.02%	-	-
#08	-	-	-	-0.01%	-	-
#09	-	-	-	-0.18%	-	-
#10	-	-	-	-0.42%	4.36%	-

Table 9. The change in maximum flows on the AC-interconnectors compared to scenario #02.

If we look into the number of hours with a maximum flow on the AC-interconnector and compare each scenario with the reference case (#02) we see that for the DK1-DE interconnector the number of hours with a maximum flow is lower than for the scenario #02. We see that only the interconnectors DK1-DE, NO1-SE3 and DK2-SE4 have change in number of hours with maximum flows compared to the reference case.

Scenario	FI-SE1	DK2-SE4	SE1-SE2	SE2-SE3	DK1-DE	NO1-SE3
#01	2	6	1	1	11	784
#02	2	6	1	1	12	787
#03	2	7	1	1	1	931
#04	2	6	1	1	1	845
#05	2	7	1	1	1	925
#06	2	7	1	1	12	934
#07	2	7	1	1	10	930
#08	2	7	1	1	10	870
#09	2	6	1	1	10	852
#10	2	6	1	1	1	843

Table 10. Number of hours with maximum flows on the AC-interconnector.

Table 10 illustrates the number of hours with a maximum flow given in each scenario. It can be seen that for the DK1-DE interconnector the number of hours with a maximum flow for scenario #04 is actually 92 pct. lower compared to the reference case (#02). But this is for a maximum flow which is 4.36 pct. higher in scenario #04 than in scenario #02. We therefore also for each scenario look into the change in number of hours with a flow equal to the maximum flow of scenario #02.

It can be seen from Table 11 that there is no change in the number of hours with a flow equal to the maximum flow of scenario #02 for the AC-interconnectors FI-SE1 and SE1-SE2. So even though the effect of implementing implicit grid losses on FennoSkan in scenario #05 is very clear in the Total welfare economic benefit calculations due to the change in flow though the Northern Sweden. The number of hours where there is a heavy flow on the AC-grid is not changed compared to the current setup (scenario #02).

Scenario	FI-SE1	DK2-SE4	SE1-SE2	SE2-SE3	DK1-DE	NO1-SE3
#01	0%	0%	0%	-100%	-8%	0%
#02	-	-	-	-	-	-
#03	0%	17%	0%	-100%	75%	18%
#04	0%	0%	0%	-100%	92%	7%
#05	0%	17%	0%	-100%	83%	18%
#06	0%	17%	0%	0%	0%	19%
#07	0%	17%	0%	-100%	-17%	18%
#08	0%	17%	0%	-100%	-17%	11%
#09	0%	0%	0%	-100%	-17%	8%
#10	0%	0%	0%	-100%	92%	7%

Table 11. Change in number of hours with a flow equal to the maximum flow of scenario #02.

It can also be seen from the table above that the change for the SE2-SE3 looks drastic, but this is not the case. There is only one hour with the maximum flow in scenario #02. So the change is simply showing that all other scenarios than scenario #06 have 0 hours of the maximum flow. The interconnector with the largest effect is the DK1-DE interconnector. For this interconnector the number of hours with a flow equal to the maximum flow of scenario #02 will for some scenarios increase by 92 pct.

It is thus clear from the calculations illustrated in the figures above that the influence on the flow on the AC-grid when implementing implicit grid losses are rather small for most interconnectors and only one interconnector is heavily affected by the implementation of implicit grid losses.

7.5 The effect under the current setup

Implicit losses on the NorNed and Baltic cables (#02 vs. #01).

If we compare scenario #02 to #01, we find the effects of the current arrangement of implicit losses on the NorNed and Baltic cables. When the implicit losses are removed in scenario #01, more power flows on the DC-interconnectors and less through the AC-grid. Thus removing the implicit grid losses on the Baltic and NorNed cable results in the loss costs of the AC-grid to decreases by 0.3 Mill. €/year, while the External loss costs for the DC-interconnectors increases by 9.1 Mill. €/year.

Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
+1.1	-1.4	+3.1	**+2.8**	+9.1	-0.3	**-6.0**

Table 12. Overview of the results of removing the implicit losses on NorNed and Baltic cables. Scenario #02 compared to scenario #01. Mill. €/year.

In the simulations, the sum of Producer and Consumer surplus drops by 0.3 Mill. €/year, Congestion income increase by 3.1 Mill. €/year, and thus the Market welfare increases by 2.8 Mill. €/year.

Putting together the Market welfare and loss costs, the Total welfare economic benefit decreases by 6 Mill. €/year by removing implicit losses on NorNed and Baltic.

7.6 The effect on loss factors on all DC-interconnectors

Several scenarios have been designed to study the effect of implicit losses on all interconnectors:

- Scenario #03: Implicit losses are implemented on all DC-interconnectors except FennoSkan.
- Scenario #04: Same as #03, but with equal loss factor on all DC-interconnectors except FennoSkan, Baltic and NorNed cables.
- Scenario #10: As #03 but with equal loss factor on all DC-interconnectors.
- Scenario #05: As #03 but with loss factor on FennoSkan included.

Impact of loss factors on all DC-interconnectors except FennoSkan (#03 vs. #02)

If we compare scenario #03 with the reference scenario (#02) we see that the Total welfare economic benefit increases by 14.4 Mill. €/year when implementing implicit losses on all DC-interconnectors in the Nordics except FennoSkan. When implementing implicit losses on the DC-interconnectors the External loss costs for the DC-interconnectors decreases by more than 23 Mill. €/year. On the other hand the implementation of implicit losses increases the flow in the AC-grid. But since there is not implemented implicit losses on FennoSkan the loss costs of the AC-grid only increases by 1.02 Mill. €/year.

Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
-6.6	+4.8	-6.0	**-7.8**	-23.3	+1.02	**+14.4**

Table 13. Overview of the results of implementing implicit losses on all DC-interconnectors except FennoSkan. Scenario #02 compared to scenario #03. Mill. €/year.

Impact of equal loss factors on all interconnectors to Germany (#03 vs. #04)

The results of scenario #03 and #04 are almost identical. The Total welfare economic benefit of scenario #04 compared to the reference scenario (#02) is quite large at approx. 14 Mill. €/year. The consequences on Consumer surplus, Produced surplus and Congestion income are also almost identical. It seems that if implementing implicit grid losses on all DC-interconnectors, it does not matter whether an equal loss factor is applied on all the interconnectors expect for FennoSkan, Baltic and NorNed cables or not. The difference is 0.1 Mill. €/year in Total welfare economic benefit in favour of scenario #03 with actual loss factors.

Scenario	Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
#03	-6.6	+4.8	-6.0	**-7.8**	-23.3	+1.02	**+14.4**
#04	-6.6	+5.0	-6.0	**-7.6**	-21.9	-0.01	**+14.3**

Table 14. Overview of the results of having the same loss factor on the interconnectors to and from DK1, DK2 and on Kontek. Scenario #03 compared to scenario #04. Mill. €/year.

Impact of equal loss factors on all interconnectors except FennoSkan (#10 vs. #03)

In scenario #10, we have simulated a situation with equal loss factors on all DC-interconnectors except FennoSkan. The loss factor is thus set to 2.5 pct. for all. While the loss costs of the AC-grid behaves similarly to scenario #03, the implementation of a unison loss factor causes less decrease in the External loss costs of the DC-interconnectors than observed in scenario #03. The Total welfare economic benefit drops from 14.4 Mill €/year in scenario #03, to about 10 Mill. € in scenario #10.

Thus it could be argued that implementing an equal loss factor to the internal Nordic interconnectors does not matter much (Scenario #04), but an equal loss factor on all DC-interconnectors including the external interconnectors is causing a significant loss to Total welfare economic. The reason being that the price differences within the Nordics are much smaller than between the Nordics and the continent.

Scenario	Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
#03	-6.6	+4.8	-6.0	**-7.8**	-23.3	+1.02	**+14.4**
#10	-10.5	+7.9	-4.3	**-6.8**	-17	+0.28	**+10**

Table 15. Overview of the results of having the same loss factor on the interconnectors to and from DK1, DK2 and on Kontek. Scenario #03 compared to scenario #10. Mill. €/year.

Impact of having implicit grid losses on FennoSkan (#05 vs. #03)

A large difference is observed when implicit loss factor is implemented on FennoSkan in scenario #05. This interconnector behaves particular due to the long detour for the power flowing between Sweden and Finland when transmission on FennoSkan becomes more expensive. The flow is shifted from FennoSkan towards the Northern interconnector SE1-FI such that the losses on the AC-grid increases severely, about four time the losses on FennoSkan itself. This causes a large increase in loss costs of the AC-grid, resulting in a decrease in Total welfare economic benefit, from 14.4 to 9.9 Mill. €/year. Thus, implementing implicit losses on FennoSkan, at least without the same arrangement on the SE1-FI AC-interconnector, produces a Total welfare economic loss of 4.5 Mill. €/year.

Scenario	Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
#03	-6.6	+4.8	-6.0	**-7.8**	-23.3	+1.02	**+14.4**
#05	-18.5	+12.9	-6.1	**-11.6**	-30.1	+8.55	**+9.9**

Table 16. Overview of the results of implementing implicit losses on FennoSkan Scenario #03 compared to scenario #05. Mill. €/year.

7.7 The effect on loss factors on all interconnectors to and from DK1

Several scenarios have been designed to study the effect of implicit losses on interconnectors to and from DK1:

- Scenario #06: Same as #02, but with a loss factor on the Skagerrak interconnector
- Scenario #07: Same as #02, but with loss factors on both Skagerrak and KontiSkan
- Scenario #08: Same as #07, but with an equal loss factor on Skagerrak and KontiSkan
- Scenario #09: equal loss factors on all interconnectors to and from DK1.

Impact of having implicit grid losses on Skagerrak (#06 vs. #02)

When comparing scenario #06 with #02, we find the effect of implementing a loss factor on the Skagerrak interconnector. The AC loss costs increases by 1.06 Mill. €/year, while the External loss costs for the DC-interconnectors decreases by 6.5 Mill. €/year. This is as expected and the Total welfare economic benefit is 2.7 Mill. €/year.

Scenario	Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
#06	-7.6	+5.8	-0.9	**-2.7**	-6.5	+1.06	**+2.7**

Table 17. Overview of the results of implementing implicit losses on Skagerrak. Scenario #06 compared to scenario #02. Mill. €/year.

Impact of having implicit grid losses on Skagerrak and KontiSkan (#07 vs. #06)

Implementing implicit gird losses on the KontiSkan interconnector adds another 1.4 Mill. €/year in Total welfare economic benefit. The AC loss cost is only hardly influenced by also implementing the implicit grid losses on the KontiSkan interconnector when already implemented on the Skagerrak interconnector. The External loss costs for the DC-interconnectors on the other hand drops by 2.1 Mill. €/year. The former does not exclude AC loss costs to increase on the German side. That however, is not calculated in this report.

Scenario	Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
#07	-9.6	+6.9	-0.8	**-3.5**	-8.6	+1.03	**+4.1**

Table 18. Overview of the results of implementing implicit losses on Skagerrak and KontiSkan. Scenario #07 compared to scenario #02. Mill. €/year.

Impact of having equal loss factors on Skagerrak and KontiSkan (#08 vs. #06)

Having an equal loss factor on both the KontiSkan and Skagerrak interconnector, has the implication of reducing the Total welfare economic benefit by 0.5 Mill. €/year.

Scenario	Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
#08	-6.5	+4.6	-0.7	**-2.6**	-6.5	+0.7	**+3.2**

Table 19. Overview of the results of implementing implicit losses with equal loss factors on Skagerrak and KontiSkan. Scenario #08 compared to scenario #02. Mill. €/year.

Impact of implementing implicit grid losses on the Great-Belt interconnector (#09 vs. #08)

In scenario #09, implicit losses are also implemented on the Great-Belt interconnector. Thus all interconnectors to and from DK1 have the same loss factor in this scenario. The Total welfare economic benefit increases by 0.6 Mill. €/year compared to scenario #08. So implementing implicit grid losses on the DK1-DK2 interconnector when already having implicit grid losses on the Skagerrak and KontiSkan interconnectors increases the Total welfare economic benefit.

Scenario	Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
#08	-6.5	+4.6	-0.7	**-2.6**	-6.5	+0.7	**+3.2**
#09	-10.3	+7.6	-1.7	**-4.4**	-8.6	+0.3	**+3.8**

Table 20. Overview of the results of implementing implicit losses on the Great-Belt interconnector with equal loss factors as on Skagerrak and KontiSkan. Scenario #09 compared to scenario #08. Mill. €/year.

Impact of implementing an equal loss factors on all interconnectors to and from DK1 (#09 vs. #02)

Implementing equal loss factors on all interconnectors to and from DK1 increases the Total welfare economic benefit by 3.8 Mill. €/year. When implementing an equal loss factor on all the interconnectors to and from DK1 the External loss costs for the DC-interconnectors decreases by 8.6 Mill. €/year, while the loss costs of the AC-grid only increases by 0.3 Mill. €/year.

Scenario	Consumer surplus (ΔCS)	Producer Surplus (ΔPS)	Congestion income (ΔCI)	**Market welfare (ΔM)**	External loss costs for DC (ΔDC)	Loss costs of AC (ΔAC)	**Total welfare economic (ΔW)**
#09	-10.3	+7.6	-1.7	**-4.4**	-8.6	+0.3	**+3.8**

Table 21. Overview of the results of implementing equal loss factors on all interconnectors to ad from DK1. Scenario #09 compared to scenario #02. Mill. €/year.

8. Conclusion

Implementing implicit losses corrects for an external effect, which from a "first-best" point of view always produces an economic efficiency gain. This is normally also true in a "second-best" world, which in our case is supported by the market simulation results. Applying a linear loss factor will reduce the benefits slightly, but does not have a substantial effect on the positive results for implementing implicit grid losses.

The only deviation from the "first-best" argument is the FennoSkan interconnector. Due to the large increase in AC losses caused by the alternative Northern flow path, we cannot see a benefit of implicit losses on FennoSkan unless the SE1-FI AC-interconnector is to be included.

Congestion income seems consistently to drop by the introduction of implicit losses. Both in theory and in practice, it seems plausible to expect the consumer surplus to drop, and the producer surplus to increase. This is however not fully firm, but might depend on the initial situation on whether the TSOs initially buy the losses inside, or outside the day-ahead market.

9. Annex

9.1 Nordic Total welfare economic benefit of the implicit loss calculations, Mill €.

Scenario	Total welfare
#01	-6.0
#02	0.0
#03	14.4
#04	14.3
#05	9.9
#06	2.7
#07	4.1
#08	3.2
#09	3.8
#10	10.0

9.2 Changes in Market welfare for each Nordic country, Mill. €.

Scenario	Norway	Sweden	Denmark	Finland
#01	2.2	0.9	-0.2	-0.1
#02	0.0	0.0	0.0	0.0
#03	-2.6	-1.2	-3.3	-0.7
#04	-1.8	-1.4	-3.8	-0.6
#05	-2.7	-1.2	-3.3	-4.5
#06	-2.2	1.1	-1.1	-0.4
#07	-2.3	0.6	-1.3	-0.5
#08	-1.5	0.1	-0.9	-0.3
#09	-1.7	0.4	-2.5	-0.6
#10	-1.2	-0.8	-3.8	-0.9

9.3 Changes in External loss costs for DC-interconnectors for each Nordic country, Mill. €.

Scenario	Norway	Sweden	Denmark	Finland
#01	7.0	2.3	-0.2	0.0
#02	0.0	0.0	0.0	0.0
#03	-3.3	-4.6	-9.0	-6.3
#04	-2.2	-4.6	-8.7	-6.3
#05	-3.3	-8.1	-9.0	-9.8
#06	-3.3	0.1	-3.3	0.0
#07	-3.3	-1.1	-4.3	0.0
#08	-2.3	-1.0	-3.2	0.0
#09	-2.2	-1.0	-5.3	0.0
#10	-0.7	-4.5	-8.7	-3.1

9.4 Changes in loss costs for AC-grid for each Nordic country, Mill. €.

Scenario	Norway	Sweden	Denmark	Finland
#01	-0,16	0,03	-0,17	0,00
#02	0,00	0,00	0,00	0,00
#03	0,09	0,93	0,22	-0,22
#04	-0,01	0,62	-0,41	-0,20
#05	0,13	6,40	0,22	1,79
#06	0,16	1,00	-0,10	0,01
#07	0,18	0,78	0,07	0,01
#08	0,10	0,46	0,09	0,00
#09	0,14	0,75	-0,57	0,01
#10	0,03	0,71	-0,42	-0,05

9.5 Price convergence for AC-grid for each scenario compared to #02

		#1	#2	#3	#4	#5	#6	#7	#8	#9	#10
DK1-DE	#hours	3625	3281	2796	2999	2810	3403	3519	3452	3130	3014
	Pct.	33%	29%	25%	27%	25%	31%	32%	31%	28%	27%
DK2-DE	#hours	3339	2688	0	0	0	2744	2748	2711	1898	0
	Pct.	30%	24%	0%	0%	0%	25%	25%	24%	17%	0%
DK2-SE4	#hours	8485	8246	7939	8315	7925	8032	7578	7619	8019	8351
	Pct.	76%	74%	71%	75%	71%	72%	68%	68%	72%	75%
FI-NO4	#hours	870	827	836	810	217	847	835	848	851	824
	Pct.	8%	7%	8%	7%	2%	8%	7%	8%	8%	7%
FI-SE1	#hours	1709	1719	1724	1678	634	1751	1719	1736	1679	1699
	Pct.	15%	15%	15%	15%	6%	16%	15%	16%	15%	15%
NO1-NO3	#hours	659	610	473	468	475	488	469	501	488	468
	Pct.	6%	5%	4%	4%	4%	4%	4%	4%	4%	4%
NO1-SE3	#hours	2077	2106	1551	1595	1578	1567	1536	1612	1606	1602
	Pct.	19%	19%	14%	14%	14%	14%	14%	14%	14%	14%
NO1A-NO2	#hours	8851	8928	9399	9265	9407	9322	9370	9349	9281	9277
	Pct.	79%	80%	84%	83%	84%	84%	84%	84%	83%	83%
NO1A-NO5	#hours	2990	2976	2703	2798	2761	2837	2740	2789	2857	2800
	Pct.	27%	27%	24%	25%	25%	25%	25%	25%	26%	25%
NO2-NO5	#hours	2166	2161	2163	2209	2236	2252	2201	2217	2266	2211
	Pct.	19%	19%	19%	20%	20%	20%	20%	20%	20%	20%
NO3-NO4	#hours	2316	2261	2165	2184	2338	2243	2190	2208	2231	2210
	Pct.	21%	20%	19%	20%	21%	20%	20%	20%	20%	20%
NO3-SE2	#hours	2000	1941	1874	1852	1958	1890	1895	1931	1932	1873
	Pct.	18%	17%	17%	17%	18%	17%	17%	17%	17%	17%
NO4-SE2	#hours	1619	1552	1493	1517	1560	1536	1538	1584	1609	1531
	Pct.	15%	14%	13%	14%	14%	14%	14%	14%	14%	14%
SE1-NO4	#hours	1946	1892	1853	1842	1802	1848	1885	1908	1907	1844
	Pct.	17%	17%	17%	17%	16%	17%	17%	17%	17%	17%
SE1-SE2	#hours	3737	3724	3622	3659	3662	3692	3675	3718	3676	3667
	Pct.	34%	33%	33%	33%	33%	33%	33%	33%	33%	33%
SE2-SE3	#hours	5368	5333	5505	5467	5344	5442	5482	5530	5452	5506
	Pct.	48%	48%	49%	49%	48%	49%	49%	50%	49%	49%
SE3-SE4	#hours	9797	9770	9681	9560	9661	9827	9703	9706	9589	9591
	Pct.	88%	88%	87%	86%	87%	88%	87%	87%	86%	86%

9.6 Price convergence for DC-interconnectors for each scenario compared to #02

		#01	#02	#03	#04	#05	#06	#07	#08	#09	#10
DK1-DK2	#hours	6724	6627	0	0	0	6566	5389	5309	864	0
	Pct.	60.38%	59.51%	0.00%	0.00%	0.00%	58.96%	48.39%	47.67%	7.76%	0.00%
DK1-NO2	#hours	3310	3260	0	0	0	403	226	258	17	0
	Pct.	29.72%	29.27%	0.00%	0.00%	0.00%	3.62%	2.03%	2.32%	0.15%	0.00%
DK1-SE3	#hours	4909	4776	0	0	0	4628	1765	1823	168	0
	Pct.	44.08%	42.89%	0.00%	0.00%	0.00%	41.56%	15.85%	16.37%	1.51%	0.00%
DK2-DE	#hours	3339	2688	0	0	0	2746	2749	2712	1899	0
	Pct.	29.98%	24.14%	0.00%	0.00%	0.00%	24.66%	24.69%	24.35%	17.05%	0.00%
EE-FI	#hours	9251	9233	0	0	0	9251	9230	9244	9239	0
	Pct.	83.07%	82.91%	0.00%	0.00%	0.00%	83.07%	82.88%	83.01%	82.97%	0.00%
FI-SE3	#hours	3008	2981	3101	3021	386	3027	3042	3037	3065	3043
	Pct.	27.01%	26.77%	27.85%	27.13%	3.47%	27.18%	27.32%	27.27%	27.52%	27.33%
NL-NO2	#hours	658	13	0	0	0	6	8	8	5	0
	Pct.	5.91%	0.12%	0.00%	0.00%	0.00%	0.05%	0.07%	0.07%	0.04%	0.00%
PL-SE4	#hours	1146	1113	0	0	0	1143	1156	1158	1164	0
	Pct.	10.29%	9.99%	0.00%	0.00%	0.00%	10.26%	10.38%	10.40%	10.45%	0.00%
SE4-DE	#hours	2037	1096	0	0	0	1091	865	844	631	0
	Pct.	18.29%	9.84%	0.00%	0.00%	0.00%	9.80%	7.77%	7.58%	5.67%	0.00%

9.7 Changes in the flows on all the AC-interconnectors in pct.

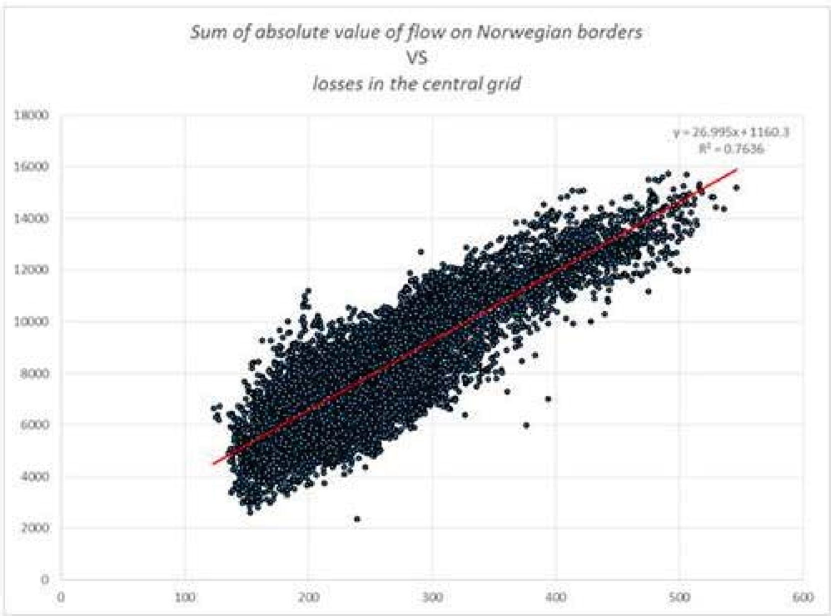
Scenario	DK1-DE	DK2 - SE4	FI - NO4	NO1 - NO3	NO1 - SE3	NO1A - NO2	NO1A - NO5	NO2 - NO5	NO3 - NO4	NO3 - SE2	NO4 - SE2	SE1 - NO4	SE1 - SE2	SE2 - SE3	SE3 - SE4	FI - SE1
#01	-4.0%	-4.3%	0.0%	0.0%	-0.1%	0.1%	-0.2%	0.3%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	-0.1%	0.0%
#02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
#03	2.6%	11.2%	0.0%	0.0%	4.9%	3.6%	-0.3%	-2.4%	1.1%	-1.4%	0.7%	0.5%	-0.7%	1.1%	2.1%	-0.7%
#04	-0.6%	0.8%	0.0%	0.0%	2.0%	1.9%	-0.2%	-1.0%	0.9%	-1.1%	0.7%	0.6%	-0.7%	0.9%	1.9%	-0.7%
#05	2.6%	11.3%	0.0%	0.0%	4.9%	3.4%	-0.3%	-2.4%	-2.2%	1.3%	1.0%	4.9%	37.3%	0.0%	2.2%	21.5%
#06	-2.3%	7.2%	0.0%	0.0%	5.1%	3.7%	-0.2%	-2.4%	0.7%	-1.4%	0.0%	-0.1%	0.2%	0.7%	1.3%	0.0%
#07	-5.6%	14.2%	0.0%	0.0%	5.1%	3.7%	-0.2%	-2.3%	0.8%	-1.4%	0.2%	0.2%	-0.1%	0.8%	1.5%	0.0%
#08	-4.9%	13.8%	0.0%	0.0%	3.4%	2.4%	-0.1%	-2.1%	0.6%	-1.0%	0.2%	0.2%	-0.1%	0.5%	1.4%	0.0%
#09	-3.1%	5.7%	0.0%	0.0%	2.6%	2.3%	0.0%	-2.3%	0.7%	-1.2%	0.3%	0.3%	0.0%	0.7%	2.2%	0.0%
#10	-0.9%	0.7%	0.0%	0.0%	2.0%	2.1%	-0.2%	-0.6%	0.9%	-1.2%	0.5%	0.5%	-0.3%	0.9%	1.8%	-0.3%

9.8 Changes in the flows on the interconnectors

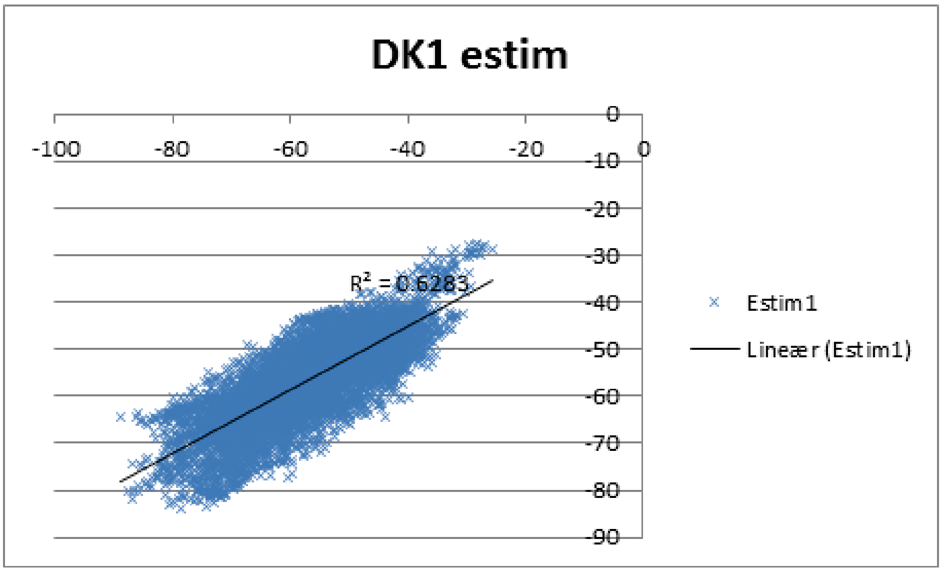
Scenario	DK1-DE	DK2 - SE4	NO1 - SE3	NO3 - SE2	NO4 - SE2	SE1 - NO4	SE2 - SE3	SE3 - SE4	FI - SE1
#01	-4.0%	-4.3%	-0.1%	0.1%	0.1%	0.1%	0.0%	-0.1%	0.0%
#02	-	-	-	-	-	-	-	-	-
#03	2.6%	11.2%	4.9%	-1.4%	0.7%	0.5%	1.1%	2.1%	-0.7%
#04	-0.6%	0.8%	2.0%	-1.1%	0.7%	0.6%	0.9%	1.9%	-0.7%
#05	2.6%	11.3%	4.9%	1.3%	1.0%	4.9%	0.0%	2.2%	21.5%
#06	-2.3%	7.2%	5.1%	-1.4%	0.0%	-0.1%	0.7%	1.3%	0.0%
#07	-5.6%	14.2%	5.1%	-1.4%	0.2%	0.2%	0.8%	1.5%	0.0%
#08	-4.9%	13.8%	3.4%	-1.0%	0.2%	0.2%	0.5%	1.4%	0.0%
#09	-3.1%	5.7%	2.6%	-1.2%	0.3%	0.3%	0.7%	2.2%	0.0%
#10	-0.9%	0.7%	2.0%	-1.2%	0.5%	0.5%	0.9%	1.8%	-0.3%

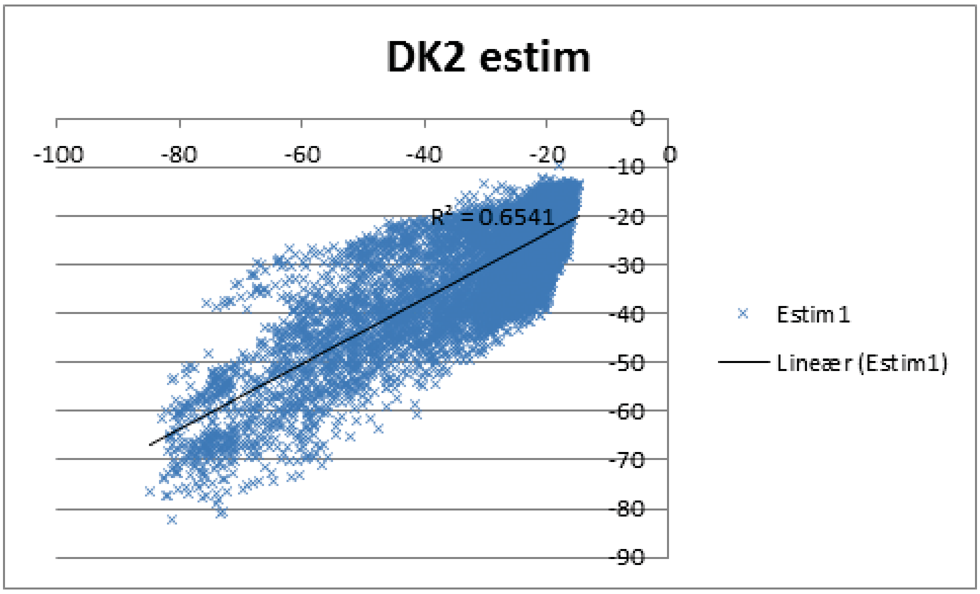
9.9 Explanation factors for the representation of AC losses

<u>Norway:</u>



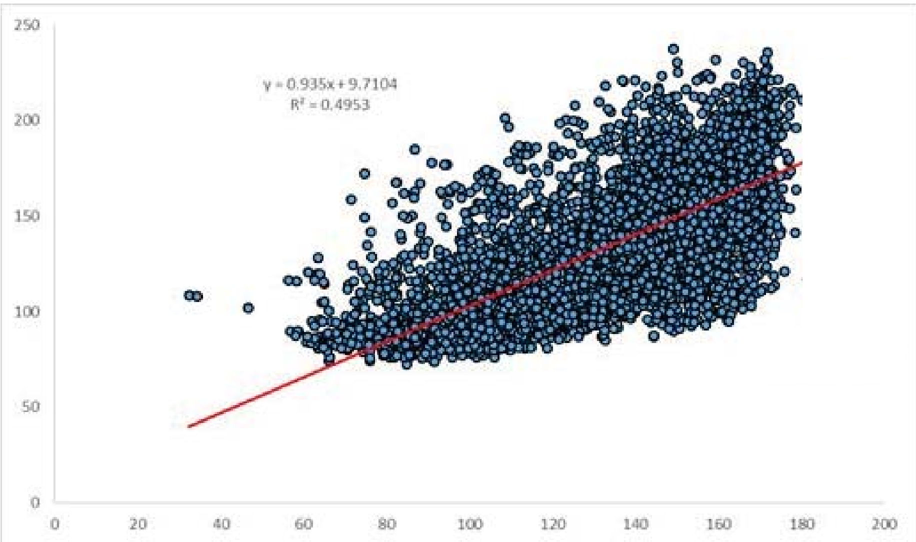
<u>Denmark:</u>





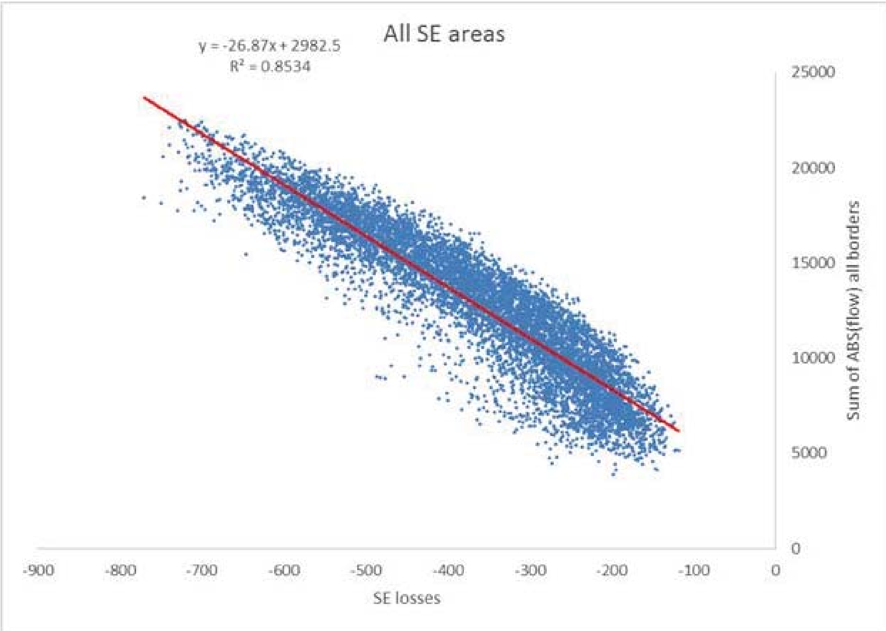
DK2 estim
-100
-80
-60
-40
-20
0
0
-10
-20
-30
-40
-50
-60
-70
-80
-90
R^2 = 0.6541
Estim1
Lineær (Estim1)

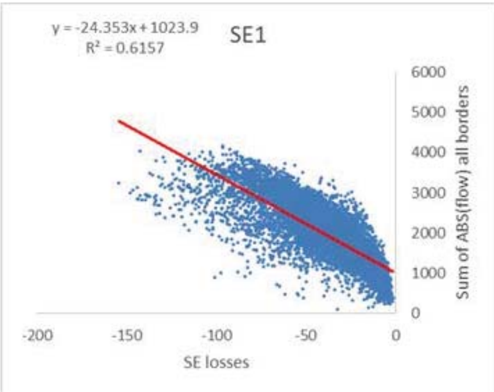
Finland:

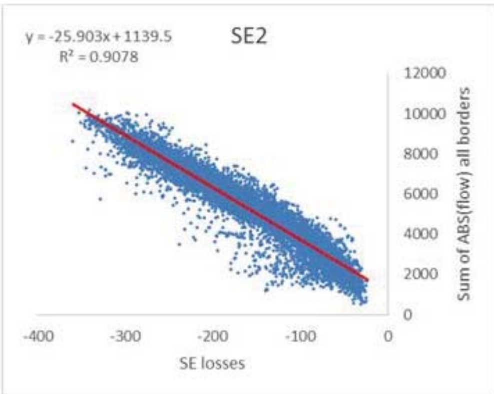


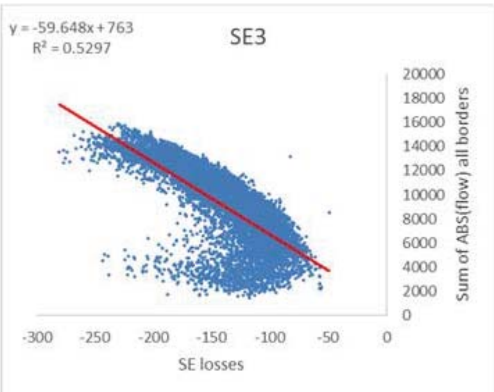
y = 0.935x + 9.7104
R^2 = 0.4953
250
200
150
100
50
0
0
20
40
60
80
100
120
140
160
180
200

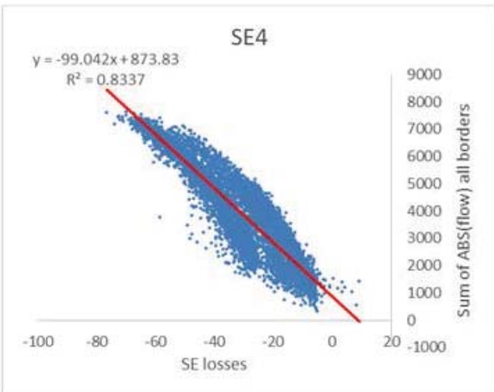
Sweden:


All SE areas
y = -26.87x + 2982.5
R² = 0.8534
Sum of ABS(flow) all borders
SE losses
25000
20000
15000
10000
5000
0
-900 -800 -700 -600 -500 -400 -300 -200 -100 0


SE1
y = -24.353x + 1023.9
R² = 0.6157
Sum of ABS(flow) all borders
SE losses
6000
5000
4000
3000
2000
1000
0
-200 -150 -100 -50 0


SE2
y = -25.903x + 1139.5
R² = 0.9078
Sum of ABS(flow) all borders
SE losses
12000
10000
8000
6000
4000
2000
0
-400 -300 -200 -100 0


SE3
y = -59.648x + 763
R² = 0.5297
Sum of ABS(flow) all borders
SE losses
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
-300 -250 -200 -150 -100 -50 0


SE4
y = -99.042x + 873.83
R² = 0.8337
Sum of ABS(flow) all borders
SE losses
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
-1000
-100 -80 -60 -40 -20 0 20

MEMORANDUM

ENERGINET Statnett

Date:
9. marts 2018

ARBITRAGE BETWEEN THE DAY-AHEAD AND INTRADAY MARKET

- Implicit grid loss handling on the Skagerrak Interconnector

If implicit handling of grid loss is introduced at a border in the day-ahead market but not in the intraday market, arbitrage opportunities can arise between the two markets, as the capacity that may be unused in the day-ahead market, as a result of optimisation with implicit grid loss handling, may be used in the intraday market.

It should be noted, however, that work is currently being done in the European intraday project, XBID, to introduce the opportunity to have implicit grid loss handling in the intraday market. It is anticipated that this – depending on the analysis – can be implemented in 2020. This means that when implicit grid loss handling on the Skagerrak Interconnector is introduced, there might be a limited period during which there will only be implicit grid loss handling in the day-ahead market.

Currently, the intraday market is primarily used in the Nordic countries for handling balancing by balance responsible parties. Implementation of implicit grid loss handling does not change the risk of the market participants and thus their fundamental need for balancing. It must therefore be expected that the trades in the intraday market will continue to be motivated by the need of balance responsible parties to balance themselves. However, the implementation of implicit grid loss handling will also result simultaneously in changes in the electricity price differences in the day-ahead market. It will therefore be more attractive for some market participants in certain situations to trade in the intraday market, but the magnitude and quantity of these transactions can be difficult to assess.

A worst case scenario will be that the entire capacity from the day-ahead market is unused but is instead used in the intraday market. This will introduce a cost for grid loss in the intraday market, where there is no congestion income, and thereby reduce the socio-economic gain that the introduction of implicit grid loss in the day-ahead market has created.[1] In the great majority of cases, the reduction will not be greater than the total socio-economic gain from the day-ahead market, and society will not be worse off with implicit grid loss handling only in the day-ahead market, compared to a situation with explicit grid loss handling in both markets. Therefore, the implementation of implicit grid loss in the day-ahead market prior to the intraday market is in line with the CACM regulation article 23 (3b). This article regarding "methodologies for operational security limits, contingencies and allocation constraints" states

1 See illustration in appendix

that “constraints intended to increase the economic surplus for single day-ahead or intraday coupling”, thereby an allocation constraint may be implemented if it increases the economic surplus of either single day-ahead or intraday coupling.

If we look at simulations in the Simulation Facility[2] of historic data over a period of 16 months from February 2014 to May 2015, we see that the number of hours in which there is no planned flow on the Skagerrak Interconnector in the day-ahead market increases from 1081 hours (corresponding to 9.7 percent of the time) when there is no implicit grid loss handling, to 2836 hours (which is 25.5 percent of the time) when implicit grid loss handling is introduced. This follows the expectation in connection with the introduction of implicit grid loss handling. We are unable to model the extent to which the electricity prices in the intraday market will result in the capacity being traded there. We have therefore used the NorNed Interconnector between Norway and the Netherlands as a case for describing the impact between the day-ahead and the intraday markets when implicit grid loss handling is not introduced in both markets.

On 18 November 2015, implicit grid loss handling was introduced in the day-ahead market on NorNed with a loss factor of 3.2 percent.

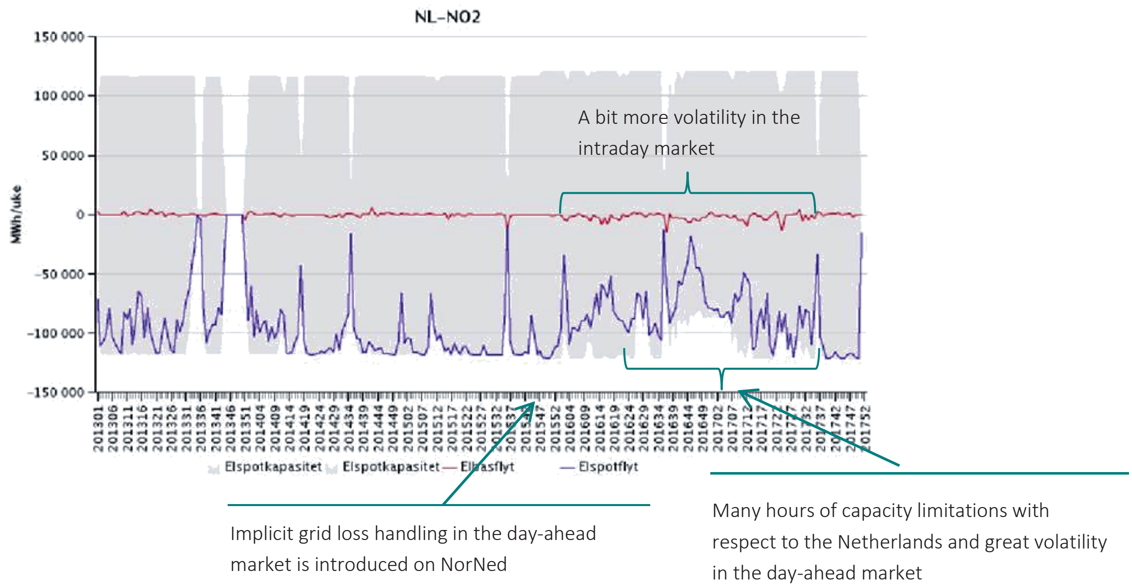


Figure 1 Trading over NorNed. Day-ahead trading (blue line), intraday trading (red line) and capacity provided to the market (grey area). The figures are stated in MWh/Week

The analysis shows a bit more volatility in the intraday market after the introduction of implicit grid loss handling in the day-ahead market. However, the impression is that these are minor ripples that cannot only be attributed to the introduction of implicit grid loss handling. It is evident that, in the same period, the day-ahead market is also more volatile and the capacity with respect to the Netherlands has been limited, which can also result in greater activity in the intraday market. All in all, it is evident that marked changes have not occurred in transactions in the intraday market after the introduction of implicit grid loss handling in the day-ahead market, and it must be concluded that the arbitrage effect between the two markets has been small.

[2] Simulation Facility is a tool that is made available to the TSOs by the electricity exchanges in Europe. The tool uses “What-if” analyses on realised historic order books and system topologies.

It is important to point out that, because of the different magnitude of the electricity price differences between the bidding areas on NorNed and the bidding areas on Skagerrak, the above analysis is not fully representative for Skagerrak.

Data for the electricity prices in the bidding areas related to NorNed show that there is an average electricity price difference of EUR 15.3, EUR 14.1 and EUR 20.8, respectively, for the years 2013, 2014 and 2015.[3] Electricity prices vary, of course, but as Figure 2 indicates, in more than 90 percent of the hours there is an electricity price difference on the NorNed Interconnector. The standard deviation of EUR 12.8, EUR 9.9 and EUR 11.4, respectively, for the same series of years indicates that approximately 70 percent of the hours have an electricity price difference that is within one standard deviation from the mean. Thus, there will be hours with a minor or no electricity price difference, but given the high average, the results indicate that there will still be a marked electricity price difference between the bidding areas.

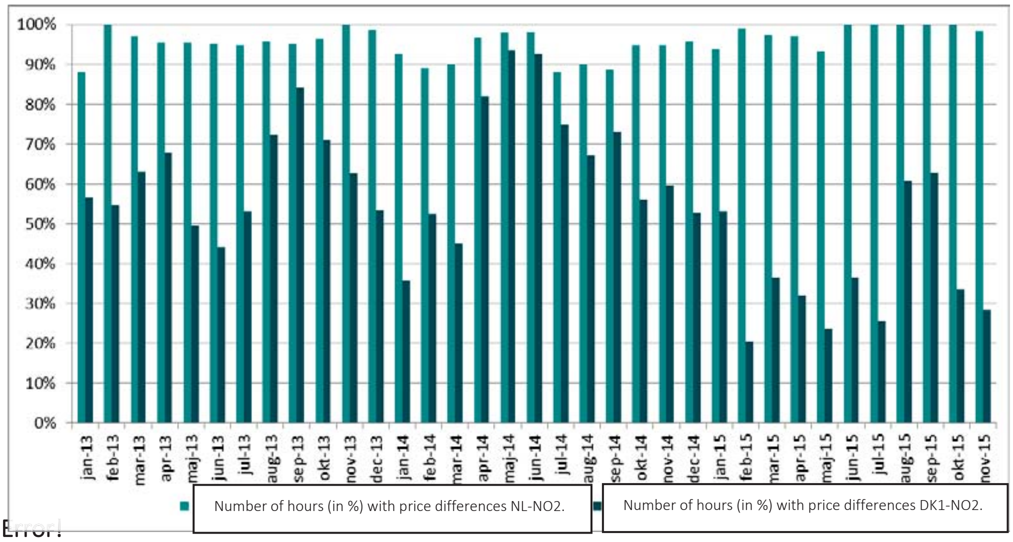


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Figure 2 Percent of hours with an electricity price difference between the bidding areas NL-NO2 and DK1-NO2

The expectation on this average market electricity price difference is that a market participant will not necessarily seek the intraday market when implicit grid loss is implemented. This is because the expectation for the great majority of hours will be that the electricity price difference in the day-ahead market is high enough to ensure a gain that can cover the introduced cost of implicit grid loss. This is also reflected in Figure 1 above, where there are no marked changes in the intraday trading after implementation of implicit grid loss on NorNed.

However, this is not the same situation for the trading on Skagerrak between the bidding areas Western Denmark and Southern Norway, where on average there is an electricity price difference of EUR 1.6, EUR 3.4 and EUR 3.3, respectively, for 2013, 2014 and 2015.[4] The standard deviation of EUR 46.5, EUR 10 and EUR 9.5, respectively, for the years 2013, 2014 and 2015 is relatively higher than in NorNed. Furthermore, between Western Denmark and Southern Norway there has only be an electricity price difference of approximately 61 percent, 65 percent and 38 percent, respectively, of the hours in the years 2013–2015. Given the low electricity price difference, compared to the high standard deviation, it suggests that the great

[3] For the sake of comparison, data are used from the period before implementation of implicit grid loss on NorNed.
[4] For the sake of comparison, data are used from the period before implementation of implicit grid loss on NorNed.

majority of hours are characterised by a minor electricity price difference, where there are usually a few hours with a high electricity price difference. For example, when seen in isolation, when there is a limitation on Skagerrak in situations with high wind production in Western Denmark.

Overall, when the electricity price difference is very low during most hours, and there is only a minor share of hours over a year with a high electricity price difference, then the expectation is that there will be greater interest among market participants in moving the trading from the day-ahead market to the intraday. This is because the smaller electricity price difference also means that the marginal grid loss cost (which is included in the electricity price in the day-ahead market) will result in a greater drag on the gain in the day-ahead market, which is why market participants may choose to instead trade in the intraday market.[5]

However, the balance responsible party who chooses to bet on this arbitrage opportunity accepts a great risk if, instead of setting a bid in the day-ahead market, it bets on obtaining a gain in the intraday market. Among other things, it is a risk with respect to the balance responsible party being exposed to any new information that may arise during the period of time from the day-ahead market to the intraday that may affect the electricity price. This is particularly also the case in Denmark, where wind production affects the electricity price to a large extent. The balance responsible party must also be sure that it has a counterpart in the intraday market, which depends on the liquidity in the market. Furthermore, many of their deliberations here are based on game theory, as the balance responsible party cannot allow itself to speculate with the entire portfolio on the above arbitrage opportunity and must also consider the acts of the other balance responsible parties. A balance responsible party will only make use of the described arbitrage opportunity if risks are made up for by the potential gain. It is concluded that, based on the minor losses on the cable, the potential gain is not high enough for there to be major shifts from the day-ahead over to the intraday market.

[5] This is also illustrated in the example on page 35 in the NWE report "NWE Day-Ahead Market Coupling Project Introduction of loss factors on interconnector capacities in NWE Market Coupling" from April, 2013.

Appendix – Illustration of worst case example

To illustrate the worst case example, let us suppose that we have a connection between area A and area B and there are only these two areas. If we assume that the connection can transfer 100 MW and further assume that there is a loss factor of 2 percent on the connection, then at full flow on the connection 2 MW of energy will be lost that is purchased by the TSO through explicit grid loss handling.

In order to ensure that the example is not complicated too much, we assume that we look at one hour, and we assume that the exchange of energy can only occur from area A to area B. It is further assumed that the capacity that is not used in the day-ahead market is fully used in the intraday market. [6]

The example below assumes that the supply and demand curves are identical in the day-ahead and the intraday market, i.e. that there are congestion income and loss costs, which is essential for the socio-economic result.

Let the electricity price in area A be P_A and the electricity price in area B be P_B.

Explicit handling of grid loss in the day-ahead market:

Day-ahead market: 10 MW flow from area B to area A $P_A = P_B = 10\ EUR$.

Congestion income is thus:

$$(P_B - P_A) * flow = (10 - 10) * 10\ MW = 0\ EUR$$

⇨ No congestion income.

The grid loss cost[7] for the TSO is:

$$lost\ energy\ * \ price\ bidding\ zone\ B = 0{,}2\ MW * 10\ EUR = 2\ EUR$$

The total TSO day-ahead cost is thus:

$$Congestion\ incomme\ - Grid\ loss\ costs = 0\ EUR - \ 2\ EUR = -2\ EUR$$

Intraday market: 90 MW flow from area B to area A

No congestion income is generated in the intraday market.

The grid loss cost for TSOs is provided by:

$$lost\ energy\ * \ price\ bidding\ zone\ B = 1{,}8\ MW * 10\ EUR = 18\ EUR$$

The total TSO intraday cost is thus:

$$Congestion\ incomme - Grid\ loss\ costs = 0\ EUR - \ 18\ EUR = -18\ EUR$$

Seen as a whole, the TSO thus has a cost of:

TSO day-ahead cost + TSO intraday cost = -20 EUR

[6] In reality, it is probably not likely that all capacity in the day-ahead market remains unused and that all trading will occur exclusively on the intraday market, based on the risk that is involved.

[7] In this entire example, the grid loss cost is calculated at the electricity price in the export area (which is B) where the loss is purchased, which is the method on Skagerrak. On the Kontek Interconnector, for example, it is always Eastern Denmark that constitutes the reference electricity price. The socio-economic loss as a result of consumer loss is generally attributed to the import area. However, this is not included in the calculation here.

By introducing implicit grid loss in the example above, where there is no full flow and no electricity price difference, the flow can become smaller while at the same time an electricity price difference arises in the day-ahead market.

<u>Implicit handling of grid loss in the day-ahead market:</u>

<u>Day-ahead market:</u> 5 MW flow from area B to area A $P_A = 10{,}2, P_B = 10\ EUR$

"Congestion income" is thus:

$$lost\ energy\ *\ price\ bidding\ zone\ B = 0{,}1\ MW * 10\ EUR = 1\ EUR$$

The grid loss cost is[8]:

$$lost\ energy\ *\ price\ bidding\ zone\ B = 0{,}1\ MW * 10\ EUR = 1\ EUR$$

The total TSO day-ahead income/cost is thus:

$$Congestion\ incomme - grid\ loss\ costs = 1\ EUR - \ 1\ EUR = 0\ EUR$$

⇨ No congestion income.

<u>Intraday market:</u> 95 MW flow from area B to area A

No congestion income is generated in the intraday market.

The grid loss cost for TSOs is provided by:

$$lost\ energy\ *\ price\ bidding\ zone\ B = 1{,}9\ MW * 10\ EUR = 19\ EUR$$

The total TSO intraday cost is thus:

$$Congestion\ incomme - grid\ loss\ costs = 0\ DKK - \ 19\ EUR = -19 EUR$$

<u>Seen as a whole, the TSO thus has a cost of:</u>

TSO day-ahead cost + TSO intraday cost = -19 EUR

Ostensibly, the cost for the TSO is reduced by EUR 1 by implementing implicit grid loss. However, this is only ostensibly, because the loss cost for the day-ahead market flow of 5MW has moved from the TSO to the market participants.

This means in principle that a surcharge must be imposed on the market participants in the day-ahead market that is equal to:

$$Loss\ factor * MW\ flow\ i\ day\ ahead\ market * price\ bidding\ zone\ B$$
$$= 0{,}02 * 5MW * 10\ EUR = \ 1\ EUR$$

The above EUR 1 , which shall be allocated to the market participants, is added to the intraday market cost of EUR 19 for the TSO, after which the total loss cost is obtained.

As with explicit loss handling, the total loss cost with implicit grid loss is thus EUR 20 as well.

Based on the underlying assumptions, this example shows that the worst case outcome from full transfer from the day-ahead to the intraday market leads to implementation of implicit grid loss not resulting in any socio-economic change in relation to the situation with explicit grid loss handling.[9]

[8] It is no longer the TSO that bears this cost. Under implicit grid loss, the cost is assigned to the consumer in the electricity price.

[9] In reality, this is probably not the case, but the expectation is nevertheless that the situation will not become worse.