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Ex post evaluation of implicit grid loss at Skagerrak interconnector.

Indhold

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Introduction

The implicit grid loss management has been in operation on the Skagerrak interconnector since February 2021. This note presents a more efficient “light handed” approach to the assessment of the first two years of operation of implicit grid loss management at the Skagerrak interconnector between BZ DK1 and NO2.

The NRA approval of implicit grid loss management from 2019 was conditional on the TSOs, Energinet and Statnett, presenting an ex-post evaluation of the operation of implicit grid loss management on the Skagerrak interconnector after two years of operation. The evaluation initially outlined by the NRAs is comprehensive, thus the expected effort to be allocated for this work might not be proportional to the outcome. Or in other words, sufficient insight from assessing the first two years of operation can be gained with less resources by choosing a more efficient approach, as explained below. Our approach and results from the assessment is presented in the following chapters.

The statement of understanding between the Danish utility regulator and the Norwegian energy regulatory authority reads as follows in the box below.

EVALUATION OF THE FIRST 2 YEARS OF OPERATION OF ILF

K. Energinet / Statnett shall produce a report in English, for the evaluation of the first 2 years of operation of the application of ILF on the Skagerrak Interconnector.

L. The evaluation shall, in the respect of the actual, experienced effects of the application of ILF on the Skagerrak Interconnector, contain:

a. Calculations of the effects on physical power flows, grid losses, and grid loss costs, for both AC grids and HVDC interconnectors, located in CCR Nordic,

b. explanations of method and parameters for modelling of losses in AC grids,

c. an analysis of socio-economic effect including market effect and grid losses,

d. an analysis of arbitrage between day-ahead and other markets,

e. an analysis of the implications for the balancing markets, notably the market for manual reserves (mFFR), and

f. a comparative analysis with a scenario of ILF not being applied on the Skagerrak Interconnector.

M. Those calculations and analyses are as a starting point to be performed according to the same analytical tools and methods, applied in “Analyses on the effects of implementing implicit grid losses in the Nordic CCR” of 30 April 2018, by the Nordic TSOs.

Source: Dec. 2019; STATEMENT OF UNDERSTANDING BETWEEN THE DANISH UTILITY REGULATOR AND THE NORWEGIAN ENERGY REGULATORY AUTHORITY, ON THE APPLICATION OF IMPLICIT LOSS FUNCTIONALITY ON THE SKAGERRAK INTERCONNECTOR.

Approach to assessment

The Danish and Norwegian TSOs, Energinet and Statnett identifies two concrete issues with the proposed assessment/evaluation by the NRAs:

1. The purpose of the entire amounts of calculations are not explicitly clear. The calculations of e.g. flows, losses and costs in a. and e. “an analysis of the implications for the balancing markets,

notably the market for manual reserves (mFFR)" cannot be a goal in itself, but can only serve as a mean to do an evaluation of the e.g. social welfare (economic) impact. Without a clear purpose of the evaluation, there is a risk of spending manpower for the analysis with no or little benefit.

2. Given that the purpose might be to assess the social welfare, an ex post evaluation, as required by the NRAs, entails (in m.) setting up a numerical simulation of the power market / system in order to follow the same approach as in the report *Analyses on the effects of implementing implicit grid losses in the Nordic CCR*. This is very cumbersome, yet achieving the goal of the analysis, but with far more resources than necessary. Moreover, given the potential negative effects from implicit grid loss management at the Skagerrak interconnector, the best solution for solving this, is to implement implicit grid loss management at the Kontiskan and Storebælt DC interconnectors as well. As per February 2024 the TSOs of Energinet and Svenska Kräftnet (together with Fingrid for Fennoskan) has launched a project with the purpose of implementing implicit grid loss management on these interconnectors.

However, the NRA statement does provide some reasoning for the evaluation which seems in line with the TSO understanding of why an ex post assessment is relevant.

> *I. As long as ILF is only implemented in the day ahead market, there exists a risk that the expected reduction in grid losses from ILF will be offset by the market in the intraday market, so that physical transmission via the Skagerrak Inter-connector does not change according to the planned day-ahead change.*
>
> *J. It should also be considered that the application of ILF solely on the Skagerrak Interconnector carries a risk that power flows may seek alternative routes, and which may potentially have been mitigated by applying ILF on the more or all of the interconnectors in Capacity Calculation Region Nordic (CCR Nordic).*

We apply this reasoning as a point of departure for our suggestion for a light handed approach. Also, the TSOs Energinet and Statnett got an approval from the national NRAs to perform a more light handed assessment on November 16th 2023.

Expected social gain from implicit grid loss management.

As a principle there is no reason to do a larger (ex post) impact assessment/evaluation of implicit grid loss management as the net gain will always be at least 0 and probably positive and never negative. The reason is that implicit grid loss management is an internalization of an externality, where the internalization can be theoretically shown always to have a positive social impact. However, in line with the leakage issues when it comes to CO_2 abatement, taxation in only EU might lead to CO_2 emissions "moving" to other non-EU countries. Doing a partially implementation on only one interconnector, when more routes exist between given source and sink, and in only one time frame (DA market), when more time frames exist, might lead to "leakage" when it comes to grid loss. A geographical "leakage" is the risk of external flows taken a detour when implicit grid loss management is not implemented on all relevant interconnector and a timeframe-"leakage" is the risk of arbitrage between market time frames, when implicit grid loss management is not implemented in all time frames.

The motivation and focus for analysing the risk of external flows and arbitrage is de facto the potential risk of not having a positive welfare impact and in a worst case can be negative:

- Compared to a situation without implicit grid loss management, *external flows* might lead to a grid loss in the AC grid and other DC interconnectors which is larger than the decrease in loss at Skagerrak in hours of little or no price difference. However, it is not given ex ante, that the grid loss followed by external flows is larger. This can only be assessed by numerical/statistical analysis.
- Compared to a situation without implicit grid loss management, the *arbitrage* will never lead to a social loss compared to the reference of doing nothing, but will only offset the potential gain obtained for the DA market. In a worst case scenario where all exchange of power on Skagerrak is moved from DA to ID, in the relevant hours, the potential gain from implicit grid loss management would only be neutralised, thus there is de facto no impacts from implementing implicit grid loss management.

So, the overall approach is the following:

- *The objective:* The purpose of the evaluation is to assess the impact in terms of social welfare.
- *The focus:* As the main (and only) concerns when it comes to negative effects of implicit grid loss on Skagerrak is the external flow and arbitrage, we will (only) focus on this in addition to welfare as there is no reason to expect that other negative effects can be significant.
- *The approach:* We will provide an estimation of welfare impact based on a simple approach where only price/flow data from Skagerrak (NO2/DK1) and adjacent interconnectors will be applied. For the results to be valid we apply the assumption that external flows are not significant. We don't need to do market simulations in order to have an idea of potential social impact. Insights can be gained by applying the actual historical data from the DA and ID market for the period February 2021 to December 2023. Yet we will try to asses the magnitude of external flows.

Methodology and result

The first step is to identify when implicit grid loss management can be identified to have had an actual impact on the power market and grid loss in the system. This is the hours where the implicit grid loss factor of 2,9% will be effective, thus in hours where the price difference between DK1 and NO2 is not higher than 2,9%. This is done in order to identify if it is possible to do any analysis at all and isolate the hours where further analysis can be done. In these hours we will/may observe flows below max capacity yet having a price difference. Only in hours of small price differences is of interest, as hours with price differences above 2,9% the DA flow on Skagerrak, as well as other part of the Nordic CCR, are not affected significantly by implicit grid loss management; the flows would be the same with and without implicit grid management.

Computing the price difference for all hours of the two-year period shows that in 20 % of all hours or 4,914 hours for the period March 2021 to December 2023, the price difference has been less than 2,9%. These are the hours that are candidate for further analysis.

Welfare assessment

The social impact is defined as the sum of the market impact and the impact on total grid loss. Implicit grid loss management is an allocation constraint, thus the pure market impact can be expected to be a loss. Market impact is understood as the sum of change in consumer surplus, producer surplus and congestion rent in the DA market. On the other hand; not exchanging electricity when the marginal cost of losses is larger than the price difference between NO2 and DK1, compared to explicit loss management, is a social gain. If gain from reduced losses on Skagerrak is larger than the social loss for market, the overall gain is positive.

Leaving out the possibility of external flows (and arbitrage) we do expect an overall positive gain from implicit grid loss management. We will calculate social gain of imp loss management by applying the approach illustrated in the figures below. Figure 1 illustrates how the grid loss can be modelled as an externality, where Figure 2 illustrate the impact we are quantifying.

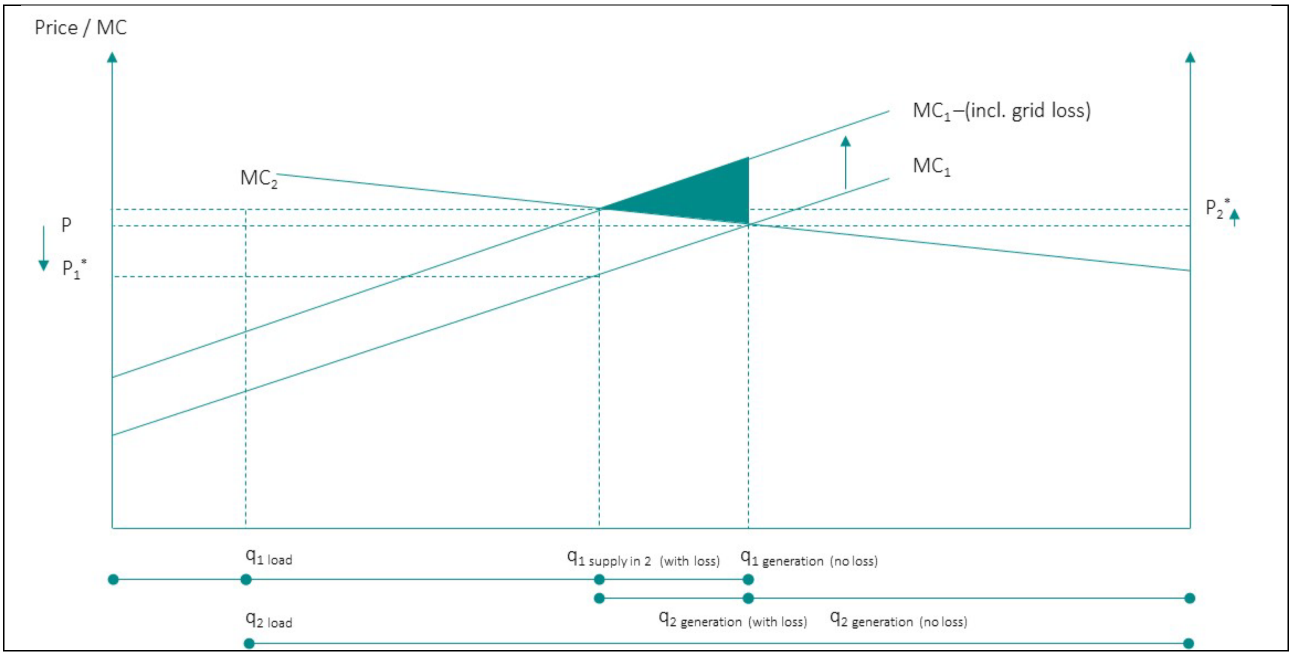
Figure 1: How grid loss can be modelled as an externality

Externality
The grid loss on an interconnector between two bidding zones can be modelled as a traditional externality. In the figure this is illustrated as a shift in the supply curve of BZ 1, for the part of the BZ1 supply curve that is applied for export to BZ2; the net export curve. The marginal external cost of grid loss is the vertical distance between MC1 with and without grid loss for the net export curve of BZ1. The reason why the net export curve is shifted vertically is that the cost of the thermal grid loss in the interconnector is now part of the marginal cost of supply for export. The MC1 curve incl. grid loss can be regarded as the import price at BZ2. The is completely parallel to modeling e.g. the CO2 externality.

The marginal social cost
An interconnector can be seen as a remote generator (from the importing BZ). The social marginal cost of such a "generator" (MC1 – incl. grid loss) is the sum of the social marginal cost of the generator that is the marginal generator to be applied for import in BZ2 *and* the value/cost of the grid loss.

The efficiency loss
If the grid loss is not part of the market prices, this will induce a cost / social efficiency loss equal the green triangle in the figure. This is a social loss as the generation in BZ1 between $q_{1\text{ supply in 2 (with loss)}}$ and $q_{1\text{ generation (no loss)}}$ could be substituted by BZ2 generation at a lower social cost: in that generation interval $MC1_{netexport}$ >MC2.

Main assumptions
- Linear loss factor (however, in the figures not a percentage as in real implementation, but a constant)
- The power market consists of two bidding zones 1 and 2. BZ 1 as the exporting zone and BZ2 as the importing zone.
- The supply curve of BZ 1 is depicted on the left Y-axis and supply curve of BZ 2 is depicted on the right Y-axis and the length of the X-axis is equal to the sum of load in BZ 1 and 2. Price elasticity of demand is zero to keep things simple
- Explicit loss purchase if left out



The impact we are quantifying, based on the light-handed approach, is basically to compute the green area in the Figure 2 below. We can see that the green area is the net impact of changes in consumer-, producer surplus and congestion rent, thus there is no reason to compute these numbers explicitly as we can compute the green directly based on the actual historical market data. We do this by the market data from DA market, where the green area is calculated as:

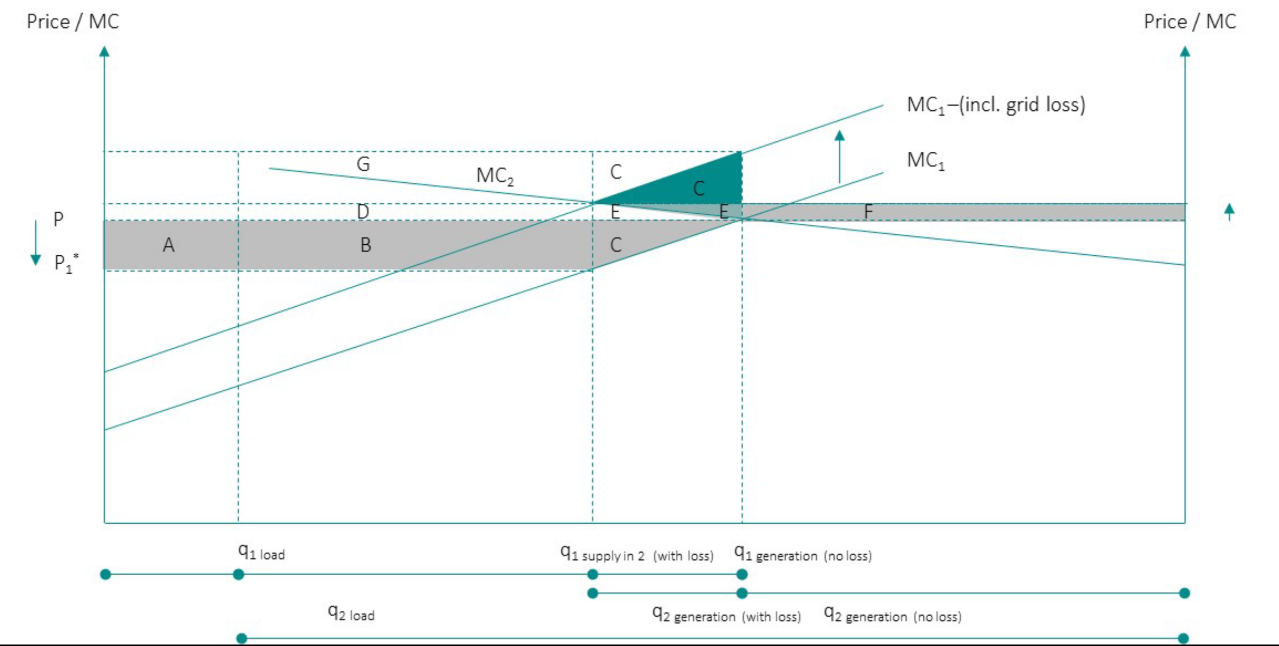
- The observed price difference between DK1 and NO2 times
- The difference between max capacity and the actual flow, which is assumed to be the decrease in flow to the implicit grid factor. This difference is the difference between $q_{1\ \text{generation (no loss)}}$ and $q_{1\ \text{generation (with loss)}}$ times
- ½ applying the formular for a triangle, assuming that the supply curves are linear and increasing in cost

Or

$$Welfare\ impact\ = \sum_{1}^{t=n} \Delta price_t x\ (\text{q1 generation (no loss)})_t - \ (\text{q1 supply in 2 (with loss)})_t\ x\ ½$$

Where *t* is market time unit (hour) and *welfare impact* is thus the total welfare impact in the observed period March 2021 to December 2023, isolating the hours where the loss factor has had an impact. We apply only the generation, thus we make an simplification and we assume that consumption has a price elasticity of 0. This assumption does not fully hold, but we don't expect this simplification to have a significant impact as a high share of the electricity consumption is close to non price elastic.

Figure 2: Welfare impact If line is initially un-congested



Impact assessment:
Pricing

- Taking the externality into account in pricing, the price in BZ1 will decrease from a common *P* to P_1^* and increase to P_2^* respectively
- Implicit loss management will insert a wedge between the “supply side” of BZ1 and the “demand side” of BZ2 just as an externality tax for any other commodity
- The generation q_1 will decrease, due to the higher cost of export (loss), thus the generation of q_2 will increase

Impact on market	Δ impact
PS BZ1	-A-B-C (grey)
PS BZ2	+E+F (grey)
CS BZ1	+A
CS BZ2	-D-E-E-F
TSO CR	+B+D
Net gain market	**-C-E**

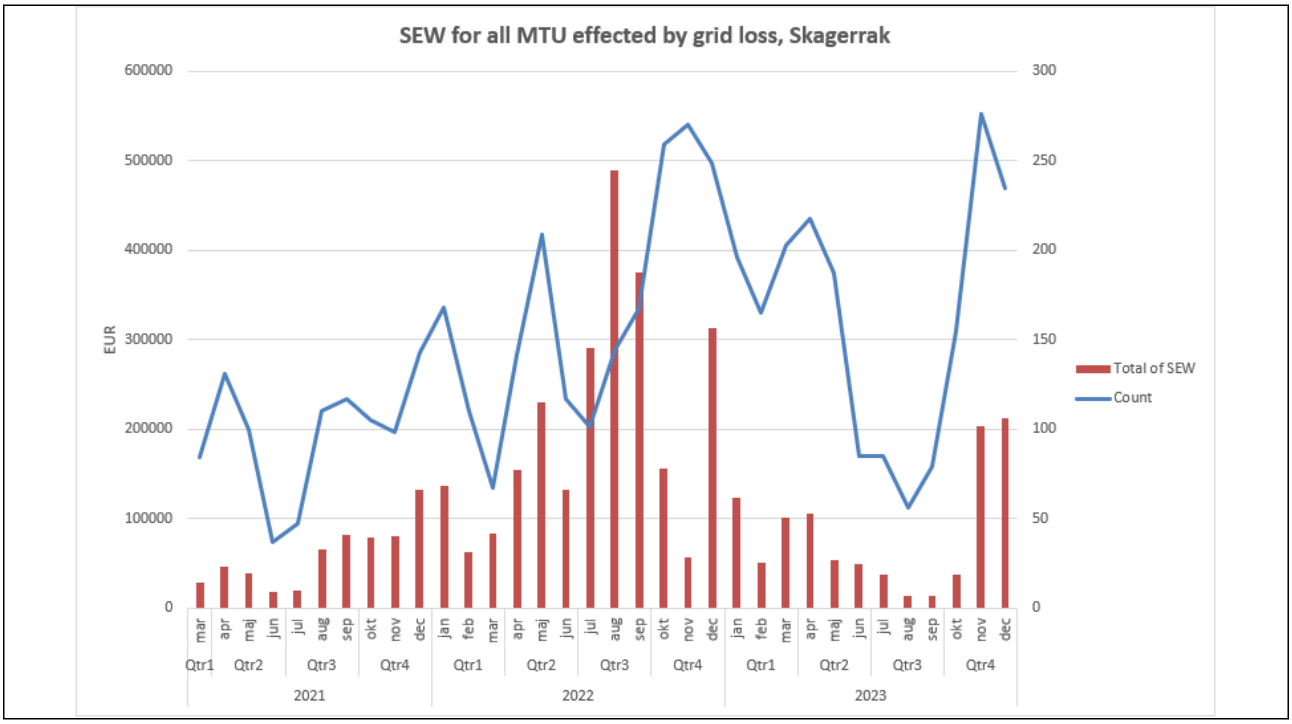
Impact on externality cost	Total cost
Cost of loss - no imp loss management	G+D+C+C+E+E
Cost of loss - with imp loss management	G+D
Reduction in cost of loss	**C+C+E+E**

Impact of social cost (sum of market and externality)	Total cost
Net gain market	-C-E
Reduction in cost of loss	C+C+E+E
Social gain of imp loss management	**C+E**

Based on the above approach, the total socio-economic welfare can be calculation to 4 mill € for the entire period or a yearly benefit of 1.4 mill €. For comparison, the simulation results in the 2018 Nordic TSO report *Analyses on the effects of implementing implicit grid losses in the Nordic CCR* shows a benefit of app. 2.7 mill. € for a 16 month period for Nordic, equal to a yearly benefit of 2 mill. €. We conclude that the realized benefit of 1.4 mill €/year are within a ballpark estimate of the expected benefit of 2 mill €/year.

Looking at the monthly distribution of socio-economic welfare, we see that main benefit is around summer 2022, SEW indicated by the red bars.

Figure 3; monthly distribution of SEW and number of hourly observation when implicit grid loss had impact



Source: Energinet EnergiDataService

At first glance this seems counter intuitive as this period was characterized by huge (marginal) cost differences between Nordic (hydro) and Continent (gas), thus the Skagerrak interconnector should be utilized 24-7. The huge utilisation of the interconnector is indeed supported by the relatively low number of observation where the implicit loss factor has an impact (blue curve). The reason why the SEW is high is because the value of saving the marginal MWh of grid loss is higher in this period compared to the remaining periods between Feb. 2021 and Dec 2023. In the summer 2022 the European energy crises peaked, thus electricity prices and cost of electricity peaked accordingly. So, even that a relatively small amount of MWh grid loss was saved during this summer, each MWh had a very high value.

Distribution of welfare gain

In the Nordic CCM version from October 2020 it says in Article 6:

> *The implicit loss factor is a correction mechanism for a negative external effect incentivising the market to respect the cost of electricity losses on HVDC interconnections in the market coupling. The implicit loss factor may be applied on an HVDC interconnection if an EU-wide welfare economic benefit can be demonstrated to the NRAs.*

It means concretely that the economic evaluation of implementation of a loss factor shall not only cover the Nordic area, but the entire SDAC (Single Day Ahead Coupling) area. From the light handed approach we cannot conclude on the distribution of welfare between the Nordics and the remaining SDAC area. But what we can conclude:

- The overall welfare is positive, thus positive EU-wide welfare economic benefit can be demonstrated to the NRAs
- We don't know the distribution of market welfare impact between Nordics and the remaining SDAC, thus we cannot say if the loss in market welfare is located in the Nordics or remaining SDAC. Most of the loss in market welfare is probably located in DK1 and NO2.
- The gain from reduced grid losses will be allocated to Danish and Norwegian consumers as the decrease in cost of explicit grid loss purchase by the TSOs will reduce consumer tariffs.

External flows

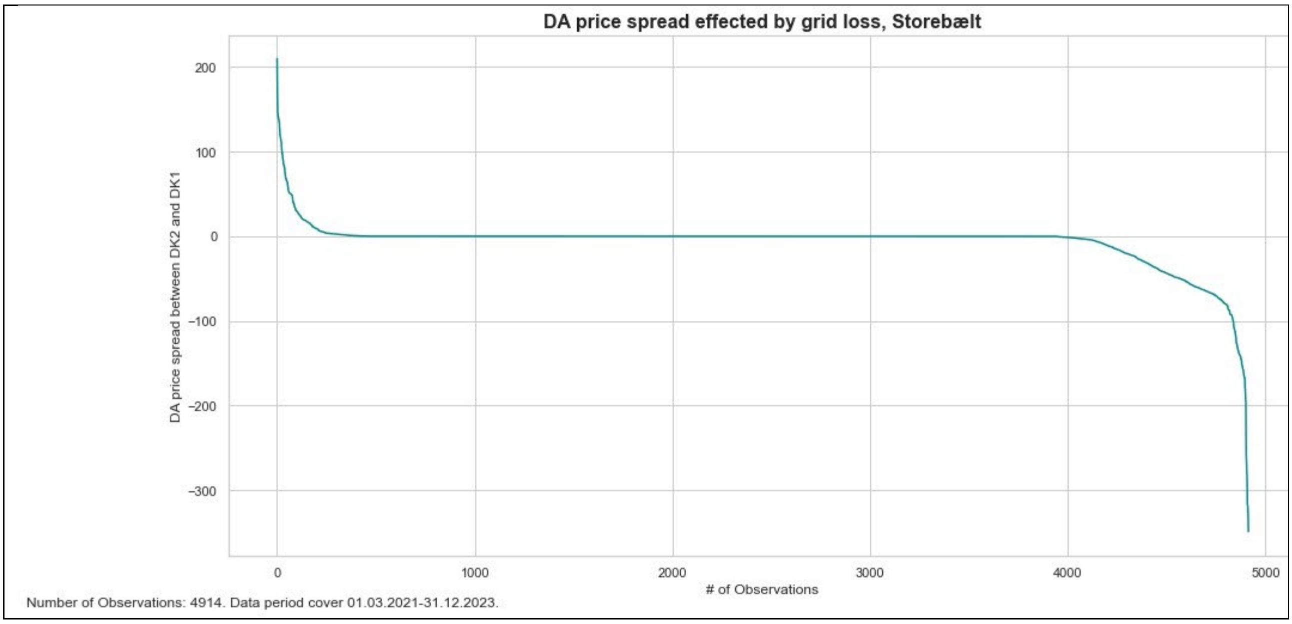
As no full monty power system simulation has been performed we need a proxy for assessing the external flows in the system and thus the impact on grid loss in the internal AC grid and other DC interconnectors. Our focus will be on flows on other DC interconnectors/routes between DK1 and NO2 as explicit historical market data exist for these. We assume that the main impact of implicit loss management on Skagerrak to be found in DK1 and NO2, thus this is also the main driver for external flows between DK1 and NO2. If data indicate no significant increase in (external) flows on relevant DC interconnectors we conclude that this holds true for the internal AC grid as well, thus we assume some correlation between internal and external flow.

For the Skagerrak interconnector, where DK1 and NO2 is the source and zink (depending on flow direction), risk of un-wanted external flows exist, going along two alternative routes; Hasle →Kontiskan (via SE3) and Storebælt (via SE 4 and DK2) and vice versa as no implicit grid loss management has been implemented. More flows can in theory also take a “detour” between NO2 and DK1 via the Nordlink (Norway/Germany) or NorNed (Norway/Nederland). However, for these interconnectors, implicit grid loss management has been in operation since the commissioning of the interconnectors, thus an increase in flow will be within the boundaries of a social welfare net gain as the externality has already been internalised.

Without simulations it is, however, difficult to decompose the actual historical DA flow between BZs into flows due to “efficient market coupling” and (additional) external flows due to imp loss at Skagerrak interconnector. As an alternative, we have applied the following proxy for the external flows. In hours where the imp loss at Skagerrak is effective, meaning hours of price difference initially not higher than the loss factor of 2,9%, we have computed the degree of congestions on Kontiskan and Storebælt. If these BZ borders are systematically congested, while Skagerrak is not, could indicate the existence of external flows. We apply the magnitude of price spread to compute the congestions, where zero price spread indicate no congestion.

In the period March 1st 2021 and December 31st 2023 implicit grid loss on Skagerrak had an impact in 4,914 hours. Figure 4 illustrates the price spread for these hours for DK1-DK2. From the figure the price spread was zero in app. 4,000 hours or 80%. This illustrates that there were no congestions in the majority of hours. We cannot rule out that there was no external flow, but in case of external flow this did not lead to (significant) congestions on this BZ border.

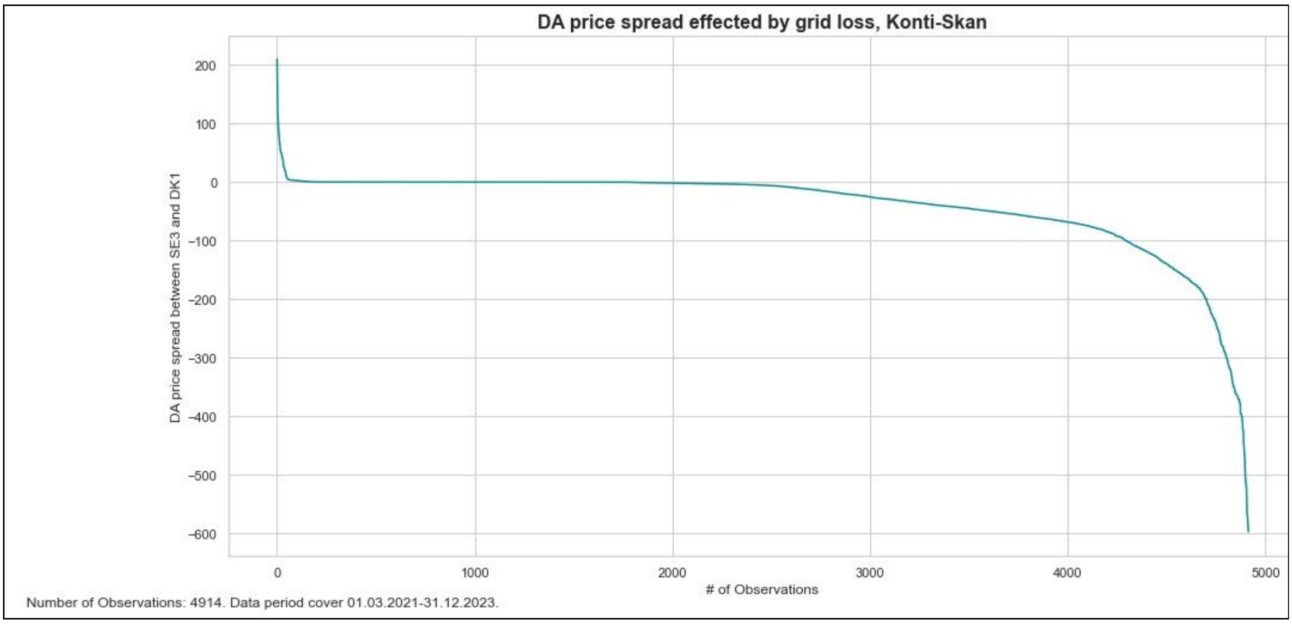
Figure 4: DA hourly price spread between DK1-DK2



Source: Energinet EnergiDataService

For the BZ border SE3-DK around 2500 hours or 50% of the relevant hours there is no price spread, thus indicating a low level of external flow, cf. Figure 5.

Figure 5: DA hourly price spread between SE3-DK1



Source: Energinet EnergiDataService

From the approach taken we cannot rule out no existing of external flow. However, the solution to the potential problem is to implement implicit grid loss management of these interconnectors as well. And this is exactly what is going on. The TSO of Energinet and Svenska Kraftnät has launched a project aiming at implementing implicit grid loss management on Kontiskan and Storebælt.

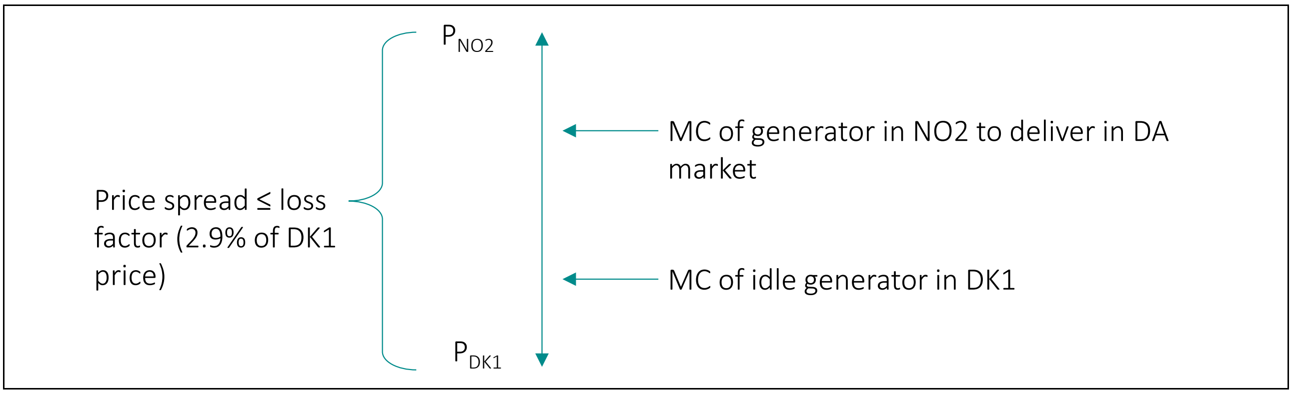
Arbitrage DA→ID

Implementing implicit grid loss in the DA market, but not the ID market, may in theory, create an arbitrage possibility for "moving" trade from DA to ID. The idea is that in the DA market implicit grid loss will create a price difference without full utilisation of the interconnector, leaving a room for arbitrage in the ID market as the cost of grid loss is not internalised. We have focused on the actual historical ID exchange on Skagerrak to identify arbitrage. If significant more electricity is traded ID compared to DA in the same price direction as DA, this might indicate arbitrage.

Leaving out the need for balancing for market participant, strategic interaction between ID and DA still can be beneficial if the individual market players can have an impact on pricing. However, we do argue that expected amount of arbitrage, due to implicit gris loss management in DA, cannot be expected to be significant. This is due to fact that it will probably not be profitable to do arbitrage. The reasoning is explained based on an example:

- Situation: NO2 high DA price zone and DK1 DA low price zone, yet there is idle interconnector capacity after the DA market is cleared (due to the implicit loss factor kicking in)
- Assume a particular generator in NO2 are set to deliver in DA market
- This NO2 generator may consider going into the ID market to find a counter part with lower marginal costs (generator) (or consumer Willingness-To-Pay) to fulfil the obligation towards the DA market
- In case this counter party shall be located in DK1 (arbitrage), this counter party shall have MC / WTP above DA price in DK1 in order to be able to supply, as the counterparty would have been activated in DA in the first place
- The potential counter party in DK1 cannot have a MC / WTP above the NO2 DA price as other potential suppliers in NO2 might be more relevant.
- It can therefore be concluded that for arbitrage to be profitable, the supply price of potential supplier of DK1 shall be between price of DK1 and NO2 and this spread cannot be larger than 2.9% of DK1 price as the price spread shall be due to the loss factor being active for this particular hour and not congestions, where the latter is due to larger differences in MC than 2.9%.
- In case price spread is above 2,9%, due to congestions, the loss factor has no real impact for these hours and this price spread would also initially be active in the ID market, thus arbitrage is not profitable (nor possible due to congestions)

Figure 6: price spread and arbitrage ID vs DA

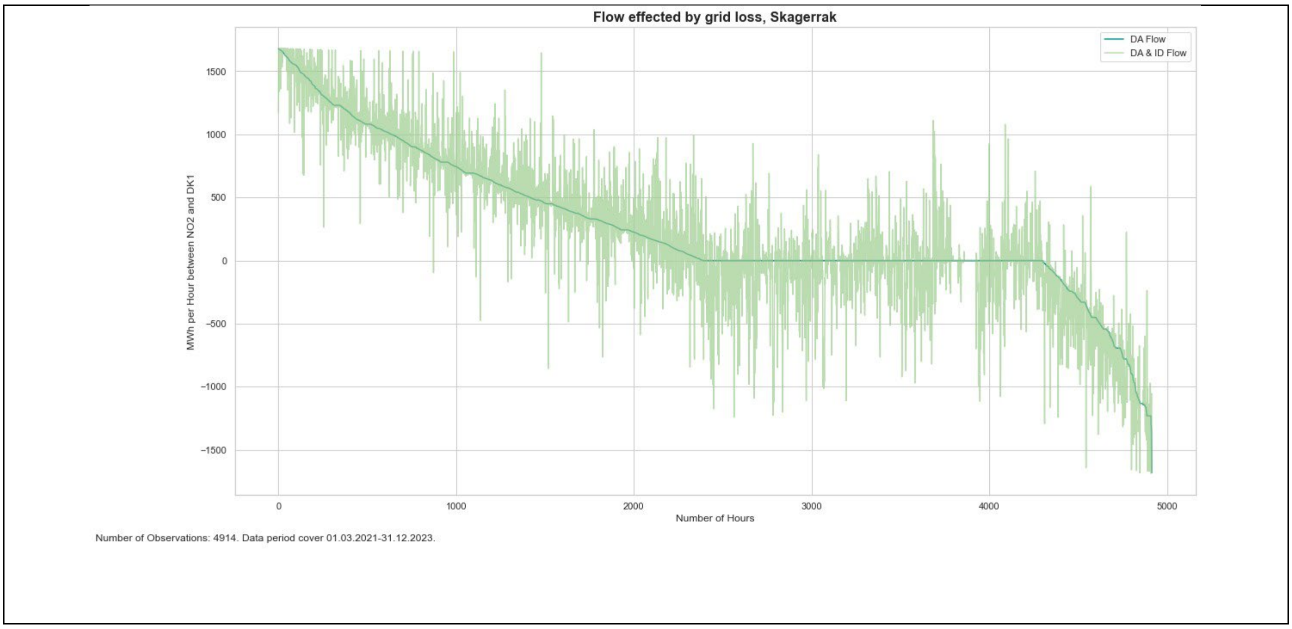


- So for arbitrage to take place, three conditions must simultaneously be fulfilled :
    - The MC of the idle generator of DK1 shall be above the DK1 DA price, otherwise it would have been activated in the DA market in DK1 in the first place
    - The MC of the idle generator of DK1 shall be lower than DA price of NO2, otherwise it will not pay for the NO2 generator to make a deal with DK1 generator
    - The price spread cannot go above the loss factor of 2.9% as a higher spread will be due to congestions, which will also be effective in the ID market
    - → this is illustrated in Figure 6.

We do assess that the likelihood for these conditions to be fulfilled as rather low, thus arbitrage may not take place.

Even though we do not expect huge amount of arbitrage, we have thus computed the ID flow in addition to the DA flow. If arbitrage takes place this will show as same direction of flow in ID as in DA. In Figure 7 we can, however, see that at first glance it does not seems to be the case. The figure shows that in case of flow different to 0, the ID flow (light green) is evenly distributed around the DA flow (the dark green duration curve).

Figure 7: Hourly DA and ID flow on Skagerrak in hours of implicit grid loss being active



Note: The dark green line is the duration curve of DA flow and the light green is the additional flow (+/-) due to ID trades. Positive numbers (above 0 on the x-axis) is flow from NO2 to DK1 and vice versa

Source: Energinet EnergiDataService

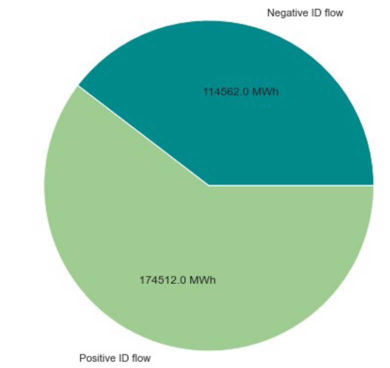
The curve in Figure 7 consist of three segments. DA flow from NO2 to DK1, the left side of the curve, zero DA flow, middle part of the curve and DA flow from DK1 to NO2, right. If we look at the amount of energy (MWh) that is contains in the ID flow for each of the three segments, we see that this is not 100% evenly distributed around the DA flow. This is illustrated in Figure 8 for each of the three segments. E.g. if DA flow is towards NO2, around 174,5 GWh is in the same direction, where only 114,5 GWh is in the opposite direction.

For DA flows towards one of the two BZs it seems that between 60-80% of the ID energy is in the same direction, illustrated in Figure 8 below. However, we do not consider this as arbitrage ID→DA due to implicit grid loss. We consider this speculation due to strategic market behavior as data on bidding behavior indicates that market players does not submit bids in accordance with best DA forecasts (reference: informal talks with NRAs).

Figure 8: distribution of ID flows (same/opposite) with DA as reference on DK1-NO2.

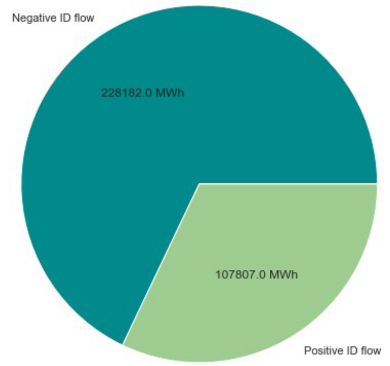
Towards DK1

Split between positive and negative ID flow effected by grid loss, positive DA flow, Skagerrak



Number of Observations: 2390. Data period cover 01.03.2021-31.12.2023.

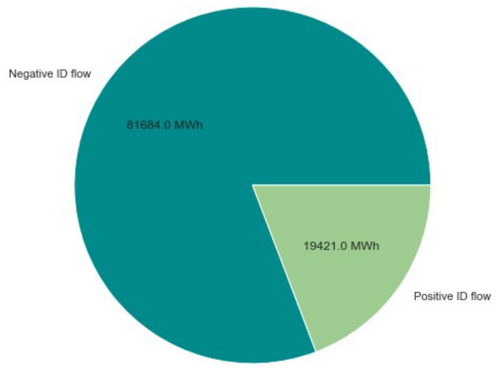
Split between positive and negative ID flow effected by grid loss, zero DA flow, Skagerrak



Number of Observations: 1909. Data period cover 01.03.2021-31.12.2023.

Towards NO2

Split between positive and negative ID flow effected by grid loss, negative DA flow, Skagerrak



Number of Observations: 615. Data period cover 01.03.2021-31.12.2023.