Single Electricity Market
(SEM)

Balancing Market and Capacity Market Options Consultation Paper

SEM-19-024

30 May 2019

EXECUTIVE SUMMARY

Since Go-Live of the amended SEM energy trading arrangements on 1st October 2018 the performance of the Balancing Market has provided some causes for concern.

The extremely high prices on 24th January 2019, caused *inter alia* by the North-South Tie Line constraint, caused particular concern and the SEM Committee decided, at their meeting on 28th March 2019, to direct SEMO to raise an Urgent Modification to the Trading & Settlement Code to implement a specific change. This Modification removed certain constraints, including the North-South Tie Line constraint, from the imbalance pricing process, in order to reduce the possibility of further extreme pricing events.

Following the implementation of this Modification on 2nd May 2019, the SEM Committee is now consulting on two further options for potential change to the balancing market design and settlement process. The first option involves changes to the Balancing Market and would remove all constraints from the imbalance pricing process. The second option involves changes to the Capacity Market settlement rules and would remove the exposure to Difference Charges for those units which were available to deliver but could not be dispatched up to meet their reliability option obligation due to a binding Operational Constraint.

This consultation paper outlines these two options, assesses them against policy and outcomes, and presents a number of questions for respondents to consider.

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1. INTRODUCTION

1.1 Background

Since Go-Live of the amended SEM energy trading arrangements on 1st October 2018 the Regulatory Authorities (RAs) have been reviewing market outcomes in the different timeframes.

The Balancing Market is a critical market in the SEM, and it was anticipated that the new market design would entail higher volatility in the Balancing Market than was seen in the original SEM gross mandatory ex-post pool. A certain amount of volatility in the Balancing Market is to be welcomed, as long as it is caused by market fundamentals, as it will encourage liquidity in the ex-ante markets and encourage market participants to be balance responsible. Since the beginning of the new market however the performance of the Balancing Market has provided some causes for concern.

The RAs are cognisant that a balancing market price should send two sets of signals. The first signal is to ensure that market participants generally trade into balance. This is sent by ensuring there is a reasonable level of volatility in the price. The second signal is to influence market participant behaviour in near to real time. It is for this reason that imbalance prices are calculated and published as near to real-time as possible. This second signal is predicated on the price, and in particular price movements, being reflective of system fundamentals. The RAs are particularly concerned that this second signal is not being sent effectively.

Over the first 6 months of the amended SEM energy trading arrangements, prices in 5-minute Imbalance Pricing Periods have gone as low as minus 1,000 €/MWh and as high as 5,636.62 €/MWh. This has fed through to 30-minute Imbalance Settlement Prices ranging from as low as minus 238 €/MWh to as high as 3,773.69 €/MWh. The RAs are not concerned around this level of volatility *per se*, but rather around some of the inputs into the price-setting process and the impact of System Operator Flags and Non-Marginal Flags on the price, and around the effect such prices have on capacity contract holders which are available but cannot deliver due to binding Operational Constraints.

24th January 2019

The high imbalance prices which occurred on 24th January 2019 and which reached 3,773.69 €/MWh in one half-hour, have caused particular concern as:

1) The SEM overall was actually long at the time; and

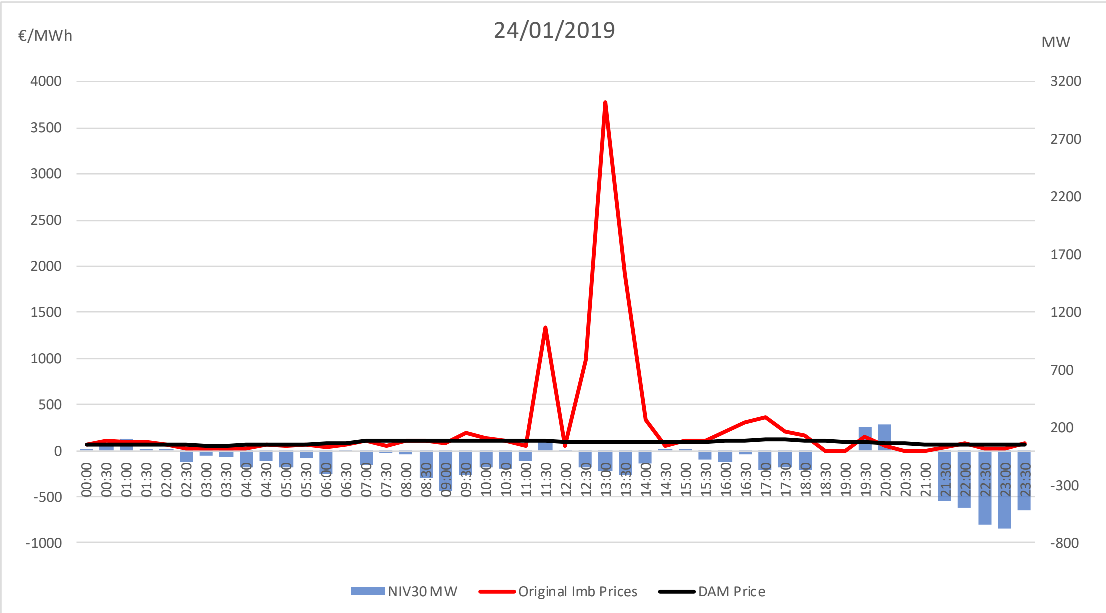
2) The imbalance price was set by an expensive peaking unit in Northern Ireland which was initially dispatched out-of-merit for non-energy reasons.

The expected behaviour of the market, generally, is that:

1) When the Net Imbalance Volume (NIV) is positive, i.e. the market is short going into the Balancing Market, then the TSO has to dispatch up units and so the imbalance price should be higher than the Day Ahead Market price; and
2) When the NIV is negative, i.e. the market is long going into the Balancing Market, then the TSO has to dispatch down units and so the imbalance price should be lower than the Day Ahead Market price.

Figure 1 below shows, for 24th January 2019, the imbalance price in red, the Day Ahead Market price in black and the NIV in blue (on the secondary axis). It can be seen that the market is long at midday (the NIV is negative), and there is nothing unusual about the Day Ahead Market price, but the Imbalance price reaches over 3,770 €/MWh.

Figure 1



The sequence of events which lead to this happening on 24th January 2019 are summarised at a high level as follows:

1) There was a high forecast of wind at the Day Ahead stage. Most of this wind was in Ireland but SEM is a single zone in Euphemia (the European Day Ahead algorithm) and so exports were scheduled in Euphemia from SEM as a whole to GB.
2) Thus Moyle (the interconnector between Northern Ireland and GB) was scheduled to export to GB. Note that Moyle has lower losses than EWIC and so is actually scheduled to export first in this scenario.

3) There was very little wind in Northern Ireland and very little margin of conventional generation.
4) An Amber Alert was called in Northern Ireland, which means that the system was one unit-trip away from Red Alert status.
5) There was considerable wind generation and significant margin of conventional generation in Ireland but the North-South Tie-Line became constrained and so no more energy could flow south-to-north from Ireland to Northern Ireland.
6) The TSO in Northern Ireland attempted to "counter-trade" with the TSO in GB (National Grid) to reduce exports on Moyle but National Grid did not accept the trades.
7) The TSO in Northern Ireland thus had to dispatch on some very expensive peaking units to ensure system security and stability in Northern Ireland.
8) The SEM overall was long but all the units in Ireland were removed from the pricing as they were "System Operator Flagged" due to the constraint on the North-South Tie-Line.
9) Most of the units in Northern Ireland were removed from the pricing as they were "Non-Marginal Flagged" due to being at their Higher Operating Limit.
10) This led to the expensive peaking units in Northern Ireland being the only units with QBOAs that were unflagged and thus free to set the price.
11) As the Price of the Marginal Energy Action (PMEA) was set by an action in the opposite direction to the NIV, the Price Average Reference (PAR) was not applied, and this further sharpened the price.

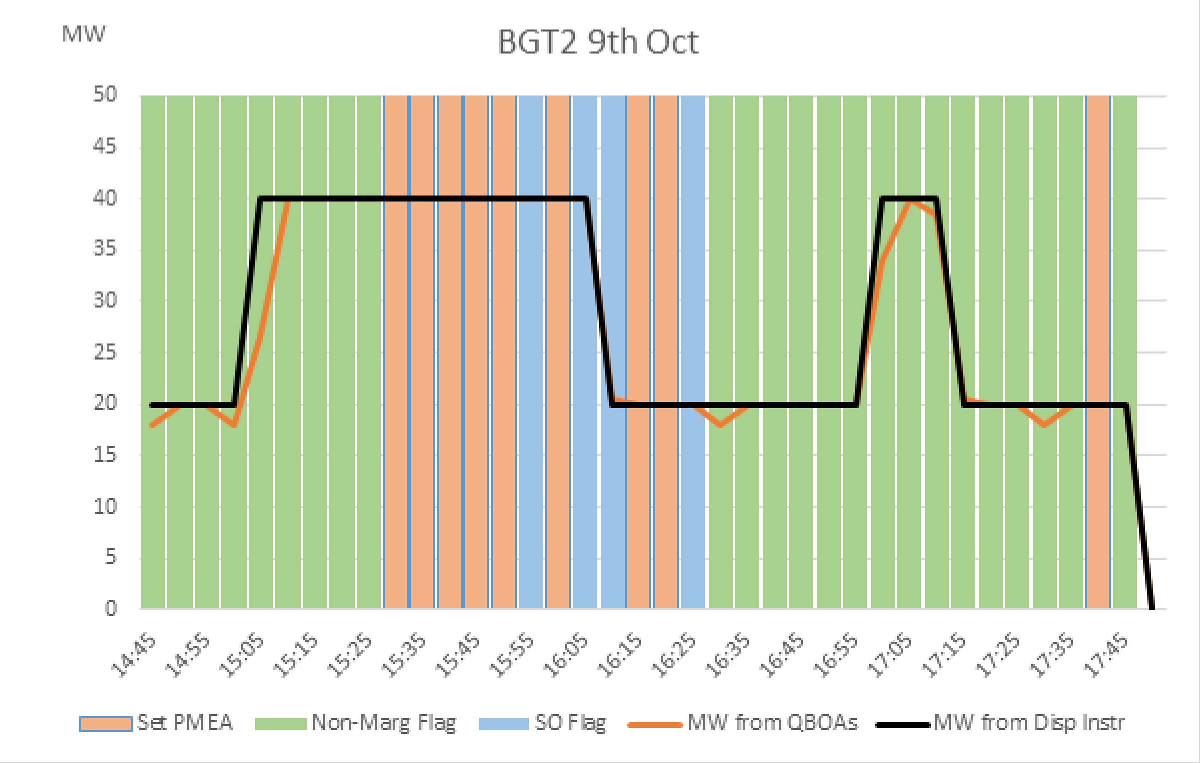
The market design is such that there should be one unconstrained pricing zone for the entire market in the Balancing Market. Where a constraint limits the TSO's choice of unit for operational reasons then this should not change the definition of the marginal unit, i.e. the unit which is actually generating in actual dispatch, and which would have generated the final MWh to meet demand had the constraint not been there. The SEM Committee is concerned that the Balancing Market design, and the detailed TSO Flagging and Tagging methodology specifically, has led to the situation, in some cases, where an expensive unit in a constrained area is setting the clearing price for the whole Balancing Market. This is not a good outcome from either a market design standpoint or an economic standpoint.

9th October 2018

On 9th October 2018, high prices were also set in the Balancing Market by an expensive peaking unit in Northern Ireland, BGT2, which had initially been dispatched out-of-merit for non-energy reasons due to an Amber Alert. On this day the Amber Alert in Northern Ireland was caused by two large units tripping in close succession. The 5-minute imbalance prices on this day reached nearly 1,800 €/MWh, which fed through to 30-minute imbalance prices of up to 1,453 €/MWh.

BGT2 was System Operator flagged or Non-Marginal flagged in most of the 5-minute periods in which it was dispatched, but in some 5-minute periods it was not flagged and set the Price of the Marginal Energy Action (PMEA) at over 5,000 €/MWh. Figure 2 below shows the unit's actual dispatch in MW over the period in question (from the Dispatch Instructions issued to the unit) and for each 5-minute period shows whether the unit was either System Operator flagged; Non-Marginal flagged; or price setting.

Figure 2



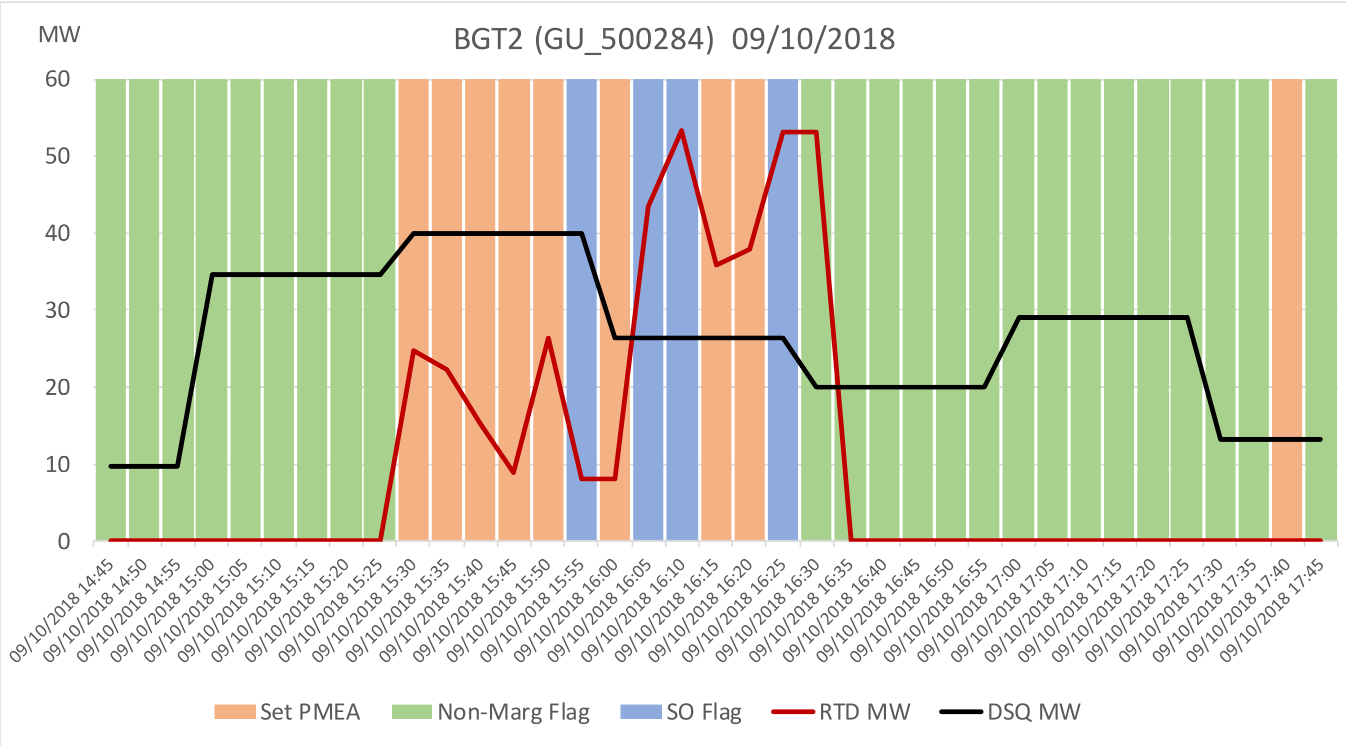
It is not possible to understand why the unit was, or was not, Non-Marginally flagged from this graph alone, due to the fact that the System Operator Flags and Non-Marginal Flags are an output of the TSOs' Real Time Dispatch (RTD) tool.

The RTD tool is the TSOs' software used to provide indicative incremental and decremental dispatch decisions close to real-time for units which are committed or scheduled to be committed. The RTD tool uses a Security Constrained Economic Dispatch optimisation to produce MW dispatch advice based on real-time system conditions and forecasts from 10 minutes before real-time for one hour at 5-minute resolution, every 5 minutes. The inputs to the RTD include Commercial Offer Data, Technical Offer Data, the commitment status of units as determined by the Real Time Commitment and Long Term Scheduling tools, the operational constraints and the actual real-time physical output of units taken from State Estimators.

The output of the RTD is an Indicative Operations Schedule which meets the operational constraints while balancing supply and demand, and which is used to provide incremental and decremental dispatch advice. Further outputs of this Indicative Operations Schedule are System Operator Flags for each unit which is bound by an operational constraint, and Non-Marginal Flags for each unit which is 1) generating at its Lower Operating Limit; 2) generating at its Higher Operating Limit; or 3) ramping up or down at its ramping limit (all within the Indicative Operations Schedule, not necessarily in actual dispatch).

Figure **3** below shows BGT2's dispatch quantities (in MW) and RTD output over the relevant periods on 9th October 2018, and for each 5-minute period shows whether the unit was SO Flagged, Non-Marginal Flagged or price setting. The RTD value in each 5-minute period comes from the most recent Indicative Operations Schedule. Where the unit is Non-Marginally Flagged it is either at its Lower Operating Limit (8MW in this case), Higher Operating Limit (58MW in this case) or ramping limit within the Indicative Operations Schedule, although in actual dispatch the unit was never at its Lower or Higher Operating Limits and over many 5-minute periods was not ramping at all.

Figure 3



After considering this example, the SEM Committee has concerns that the non-marginal flagging element of the imbalance pricing process is creating undue and unintuitive volatility in pricing outcomes, and is thus undermining the value of the imbalance price as a signal to market participants to get into balance.

Negative Prices

The SEM Committee is also concerned regarding the level of negative prices that have occurred since 1st October 2018. There have been a significant number of instances where the imbalance price has been set at a negative value by decremental bid prices submitted by a small number of units which have priority dispatch. This occurs under the current imbalance pricing methodology where all available non-priority dispatch units have been dispatched down to their Lower Operating Limit and the TSO must begin dispatching down units with priority dispatch in order to balance supply and demand, as units at their Lower Operating Limit (in the RTD Schedule) are Non-Marginally flagged. The SEM Committee is mindful that these negative prices could have significant effects on the consumer via their effect on the TSOs' Dispatch Balancing Costs (DBCs) and the PSO Levy in Ireland.

1.2 Initial steps taken

The SEM Committee decided, at their meeting on 28th March 2019, to direct SEMO to raise an Urgent Modification to the Trading & Settlement Code to implement a specific change in order to reduce the possibility of further extreme pricing events, while further approaches are investigated and developed (including this consultation).

This change involves the removal of a number of System Operator Flags in the imbalance pricing algorithm. The System Operator Flags to be removed relate to constraints that relate to upper MW limits on the Transmission System. These constraints are listed below:

- **S_MWR_ROI** – upper MW limit on transfers from Ireland to Northern Ireland on the North-South Tie-Line. Also takes into account the rescue/reserve flows that could occur immediately post fault inclusive of operating reserve requirements; this is required to ensure the limits of the Tie-Line are respected.
- **S_MWR_NI** – upper MW limit on transfers from Northern Ireland to Ireland on the North-South Tie-Line. Also takes into account the rescue/reserve flows that could occur immediately post fault inclusive of operating reserve requirements; this is required to ensure the limits of the Tie-Line are respected.
- **S_MWMAX_CRK_MW** – upper MW limit on exports from the Cork area.
- **SWMAX_STH_MW** – upper MW limit on exports from the Southern region.

The rationale for this change is to exclude System Operator Flags relating to these constraints from the imbalance pricing process as they have had the unintended consequence of causing extremely high prices to date or have the potential to do so in future given constraints in different areas of the system.

This proposed change (Mod_09_19) was approved at the TSC Modifications Committee Meeting 91 on 18th April 2019, and was subsequently implemented by SEMO effective from 2nd May 2019[1].

[1] All information on Mod_09_19 on SEMO website link here.

1.3 Further options

Two further options are being consulted upon in this paper.

The first option involves changes to the Balancing Market and is called “Simple NIV tagging”. Simple NIV tagging removes all System Operator Flags and Non-Marginal Flags from the imbalance pricing algorithm so that the most expensive actions are NIV-tagged from the top (or bottom) of the stack of actions until the stack of actions left for pricing is equal in volume and direction to the NIV. The effect of Simple NIV tagging is to use price and the NIV itself as the system to identify energy and non-energy actions. Any actions with a price which is more expensive than the marginal action, and any actions in the opposite direction to the NIV, are identified as non-energy actions.

The second option involves changes to the Capacity Market and would remove the exposure to Difference Charges for those units which were available to deliver but could not be dispatched up to meet their reliability option obligation due to a binding Operational Constraint.

The rest of this consultation paper further outlines these two options, assesses them against policy and outcomes, and presents questions for respondents to consider. The SEM Committee are open to alternatives and would welcome suggestions from respondents. A question relating to alternatives is provided in section 3.5.

2. OPTION ONE: SIMPLE NIV TAGGING IN THE BALANCING MARKET

2.1 Introduction

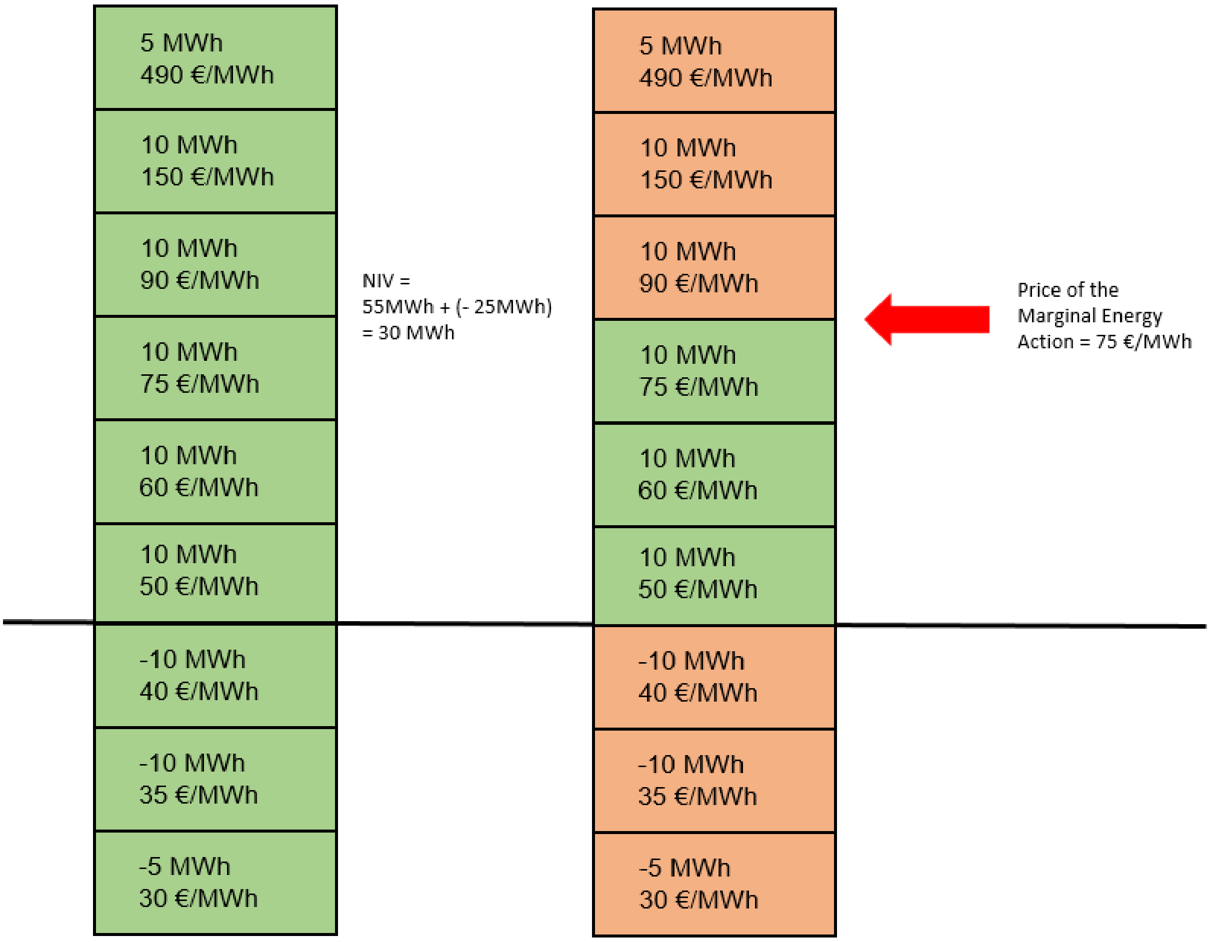
There is an option to amend the Flagging and Tagging Approach being used in the Balancing Market by removing the System Operator Flags and Non-Marginal Flags from the imbalance pricing algorithm. This option was referenced by the SEM Committee previously in its Amended Trading & Settlement Code decision paper (SEM-17-024) as a mechanism open to the SEM Committee if the imbalance price was unduly volatile (this is outlined in further detail in the next section).

The effect of removing the System Operator Flags and Non-Marginal Flags from the imbalance pricing algorithm is that the most expensive actions are NIV-tagged from the top (or bottom) of the stack of actions until the stack of actions left for pricing is equal in volume and direction to the NIV. This is why this option is referred to as “Simple NIV tagging”.

The effect of Simple NIV tagging is to use price and the NIV itself as the system to identify energy and non-energy actions. Any actions with a price which is more expensive than the “price of the marginal energy action”, and any actions in the opposite direction to the NIV, are identified as non-energy actions.

Figure 4 below outlines an example of imbalance pricing using Simple NIV tagging. In this example there are 55MWh of incremental actions and 25MWh of decremental actions in the stack. Therefore the NIV is 30MWh. The most expensive actions are NIV-tagged from the top of the stack of actions until the stack of actions left for pricing is equal to 30MWh. The Price of the Marginal Energy Action is the price of the most expensive untagged action, which in this example is 75 €/MWh.

Figure 4



It should be noted that the system constraints and unit constraints are not removed from the TSOs' scheduling and dispatch tools under this option. Therefore only the imbalance pricing algorithm is affected by this option, not scheduling and dispatch itself.

This section first assesses the Simple NIV tagging option against the I-SEM market design. Then analysis is presented on both the actual imbalance prices which occurred in the five months subsequent to I-SEM Go-Live on 1st October 2018, and the theoretical imbalance prices which would have pertained if Simple NIV tagging had been in place, and Simple NIV tagging is assessed against these results. Finally a number of consultation questions are presented for respondents to consider.

2.2 Assessment of Simple NIV tagging with regards to the market design

This section assesses the Simple NIV tagging option against the I-SEM market design. The option is assessed against the High Level Design; the Detailed Design; the Detailed Rules and Implementation Stage; and the market power mitigation decision.

The High Level Design

The I-SEM High Level Design (HLD) decision paper[2], by necessity, left some important definitions and identifications to the detailed design stage and detailed rules & implementation stage. Most importantly, the definition of the marginal unit for energy balancing actions and the TSO system to identify energy and non-energy actions were left to later stages.

The HLD was clear and unambiguous that:

- A marginal pricing mechanism would be employed for energy balancing actions; and
- There must be only one imbalance price in each time period.

Simple NIV tagging is in line with the HLD, as:

- it defines the "marginal unit for energy balancing actions" as that unit which produced the last MWh of energy which met the NIV (or that unit which was turned down to meet the NIV, in the case where the market is long);
- it is a marginal pricing mechanism;
- it produces only one imbalance price in each time period; and
- it uses price and the NIV itself as the system to identify energy and non-energy actions. Any action with a price which is more expensive than the marginal action, and any action in the opposite direction to the NIV, is identified as non-energy.

The Detailed Design

The I-SEM detailed design (markets) consultation paper[3] put forward four options regarding imbalance pricing, which were:

1) Flagging and Tagging Approach;
2) Simple Stack;

[2] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-14-085a%20I-SEM%20SEMC%20Decision%20on%20HLD.pdf
[3] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-15-026%20I-SEM%20ETA%20Markets%20Consultation%20Paper_0.pdf

3) Unconstrained Stack with Plant Dynamics Included; and
4) Unconstrained Unit from Actual Dispatch.

In the I-SEM detailed design (markets) decision paper[4], Options 2 and 3 were ruled out by SEM Committee as they involved the use of an unconstrained schedule, similar to that used in the old SEM, to set the imbalance price and it was decided that only units that were actually physically delivering energy (or actually physically being turned down) should be able to set the imbalance price.

The SEM Committee chose the Flagging and Tagging Approach (Option 1) from the remaining two options as:

- it sets the price on the most expensive action taken by the TSOs, that is not tagged as non-energy, to meet the net imbalance volume (NIV);
- the Unconstrained Unit from Actual Dispatch (Option 4) would on the other hand identify the price of the next unconstrained action that could be taken by the TSO; and
- it was considered to be more strongly aligned with the intention of the HLD as it identifies the marginal action taken to meet the NIV.

The SEM Committee views Simple NIV tagging as being in line with these detailed design policy decisions.

The detailed design (markets) decision paper left the identification of energy and non-energy actions to the Detailed Rules and Implementation stage, but outlined that:

- Imbalance prices should be based on the actions taken by the TSO to balance the system;
- The approach should be capable of delivering prices shortly after the trading period;
- The approach should not be overly influenced by any TSO subjectivity in determining which actions, or parts of actions, are classified as non-energy and thus excluded from the calculation of imbalance prices; and
- The basis of the price calculation should be transparent.

Simple NIV tagging meets all of these criteria. In the context of the detailed design decision:

- The imbalance prices which result from Simple NIV tagging are based on the actions taken by the TSO to balance the system;
- It delivers prices shortly after the trading period;
- It is not influenced by any TSO subjectivity in determining which actions, or parts of actions, are classified as non-energy and thus excluded from the calculation of imbalance prices;

[4] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-15-065%20I-SEM%20ETA%20Markets%20Decision%20Paper.pdf

- The basis of the price calculation is transparent;
- The process for the classification of actions taken by the TSOs avoids ambiguity; and
- It is completely automated.

The Detailed Rules and Implementation stage

The aim of the detailed rules and implementation stage was to translate the relevant I-SEM detailed design decisions into:

- the amended Trading & Settlement Code; and
- TSO/Market Operator systems which would implement said Code.

A Market Rules Working Group (MRWG) was established to work on this and included the TSOs, the RAs and market participants.

The concept of System Operator Flags and Non-Marginal Flags being taken from the TSOs' Real Time Dispatch tool and used to identify energy and non-energy actions was introduced to the design during this stage. The concept of a 5-minute Imbalance Pricing Period (IPP) was also introduced to the design during this stage, in order that the System Operator Flags and Non-Marginal Flags could be taken directly from the Real Time Dispatch tool as it produces schedules at 5-minute resolution.

The SEM Committee published an Amended Trading and Settlement Code decision paper[5] alongside the Amended Trading and Settlement Code itself. In this paper the SEM Committee outlined that it understood the concerns expressed by market participants regarding the potential volatility of imbalance prices and noted that the Trading and Settlement Code Amendments provided a number of potential mechanisms available in the event that imbalance prices were to be unduly volatile to the extent of negatively affecting efficient trading across market timeframes. The SEM Committee highlighted the ability to turn off the System Operator flagging and Non-Marginal flagging steps of the Flagging and Tagging process, which would lead to a greater level of NIV tagging of expensive actions in order to reach the NIV, as one potential mechanism to reduce volatility should it be required.

Market Power mitigation

Local market power exists in electricity markets when only a subset of available units, and in some cases only a single unit, can meet certain operational constraints and so the TSOs'

[5] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-17-024%20Trading%20and%20Settlement%20Code%20Amendments%20Decision%20Paper_0.pdf

choices in dispatch are limited. Such units may, or in some cases must, be dispatched by the TSO even if their bid-offers are out-of-merit.

The SEM Committee's I-SEM Market Power Mitigation decision paper[6] outlined that the Flagging and Tagging Approach combined with the application of bidding controls to units' complex 3-part offers would mitigate local market power in the Balancing Market. This was considered to be the case as any action taken out-of-merit to meet operational constraints would be flagged as a non-energy action, would not set the imbalance price, and would be settled at the unit's complex 3-part offer (or the imbalance price).

The SEM Committee considers, however, that the current Flagging and Tagging Approach is not mitigating local market power in all scenarios as intended. For example, units in Northern Ireland have local market power when south-to-north flows on the North-South Tie-Line are binding, but are not automatically flagged out of the imbalance pricing process, as was seen on 24th January 2019. MW transmission constraints are not explicitly System Operator flagged in the Real Time Dispatch schedule[7], so actions on units that have local market power due to such constraints are not automatically being flagged as non-energy actions (for MW transmission constraint reasons, although they could be flagged for some other reason).

The SEM Committee considers that Simple NIV tagging, on the other hand, is in line with the SEM Committee's market power mitigation decision. Under Simple NIV tagging any actions with a price which is more expensive than the marginal action are identified as non-energy actions and settled at their complex 3-part offer (or the imbalance price).

Decremental Bids from Priority Dispatch Units

The I-SEM Detailed Design (building blocks) decision paper[8] outlined that decremental prices submitted by units with priority dispatch would be used for settlement purposes only and would not be price setting in the Balancing Market. The SEM Committee considers that there was a failure to implement this policy decision during the detailed rules and implementation stage. There have been a significant number of instances where the imbalance price has been set at a negative value by decremental bid prices submitted by units which have priority dispatch. This often occurs under the current pricing methodology where all available units have been dispatched down to their Lower Operating Limit and the TSO must begin dispatching down units with priority dispatch in order to balance supply and

[6] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-024%20I-SEM%20Market%20Power%20Decision%20Paper.pdf

[7] The S_MWR_ROI, S_MWR_NI, S_NWMAX_CRK_MW and SWMAX_STH_MW constraints were exceptions to this but they have been removed from the imbalance pricing process. In any event they were not being applied in such a way that would mitigate local market power.

[8] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-15-064%20I-SEM%20ETA%20Markets%20Building%20Blocks%20Decision%20Papers.pdf

demand, as units at their Lower Operating Limit (in the RTD Schedule) are Non-Marginally flagged.

While Simple NIV tagging by itself does not explicitly implement this policy decision it significantly reduces the instances described above as units dispatched down to their Lower Operating Limit are not automatically precluded from setting the imbalance price.

2.3 Assessment of Simple NIV tagging with regards to modelling results

The TSOs have modelled the prices that would have pertained for the first five months of the revised SEM if Simple NIV tagging had been in place and provided this data, both 5-minute prices and 30-minute prices, to the RAs.

This section presents summary analysis of both the actual 30-minute imbalance prices (called "original imbalance prices" hereafter) which occurred in the five months subsequent to I-SEM Go-Live on 1st October 2018, and the 30-minute imbalance prices which would have pertained if Simple NIV tagging had been in place.

Note that further detailed analysis is presented in APPENDIX: DETAILED ANALYSIS OF SIMPLE NIV TAGGING.

Descriptive Statistics

Table 1 below outlines descriptive statistics for the NIV (in MW), the original imbalance price, the Simple NIV price, the Day Ahead Market (DAM) price, the Market Back Up price (which is a weighted average of the DAM price and IDM prices), the System Demand and Wind Generation.

Table 1

	NIV30 (MW)	Original Imbalance Price (€/MWh)	Simple NIV Price (€/MWh)	DAM Price (€/MWh)	BackUp Price (€/MWh)	System Demand (MW)	Wind Generation (MW)
Average	63.59	66.06	72.06	70.40	70.398	4464.31	1669.65
Median	71.64	56.19	55.52	66.45	66.40	4623.43	1630.84
Max	1316	3773.69	635.57	365.04	365.24	6485.12	3927.88
Min	-1305	-281.16	-144.49	-10.29	-10.64	2678.34	23.55
Standard Deviation	355.12	89.70	61.37	31.46	31.43	866.02	984.98
Coefficient of Variation	5.58	1.36	0.85	0.447	0.446	0.19	0.59
Kurtosis	0.541	471.577	15.302	13.389	13.253	-1.111	-1.141

The Simple NIV prices have a significantly lower standard deviation and coefficient of variation than the original imbalance prices. However, they have a significantly higher standard deviation and coefficient of variation than the DAM price, which is important as the imbalance price should still allow for some price volatility. The kurtosis of the Simple NIV prices are significantly lower than that of the original prices, while still being higher than that of the DAM prices.

The Simple NIV prices have a lower maximum price, and a less negative minimum price, than the original imbalance prices, and a higher average price than the original imbalance prices (due to less negative prices). Indeed the average Simple NIV price is higher than the average DAM price, while the average original imbalance price is lower than the DAM price. This is more in line with expectations as the average NIV over the period was positive at 62.59 MW.

Correlations

Table 2 below shows the correlation of each variable with every other variable.
The most important correlations for this analysis are highlighted in red but there are other interesting correlations also.

Table 2

	NIV30	Original Imbalance Price	Simple NIV Price	DAM Price	BackUp Price	System Demand	Wind Generation
NIV30		0.484	0.714	0.320	0.315	0.182	-0.407
Original Price			0.519	0.282	0.285	0.235	-0.230
Simple NIV Price				0.326	0.313	0.208	-0.354
DAM Price					0.99	0.527	-0.424
BackUp Price						0.518	-0.425
System Demand							0.092
Wind Generation							

Scatter Plots

Figure 5 below shows a scatter plot of the 30-minute prices against the NIV, with prices on the vertical axis and the NIV (in MW) on the horizontal axis. Figure 6 is a "zoomed in" version of the same scatter plot. The original imbalance prices are the blue dots and the Simple NIV prices are the orange dots.

The outlier extremely high prices are clear in the original imbalance prices. Some of these occur when the NIV is negative (i.e. the market is long) which is not an expected outcome. The greater number of negative prices is also clear in the original imbalance prices. Some of the most negative price occur when the market is not that long, or indeed is short (i.e. the NIV is positive), which is again not an expected outcome.

Figure 5

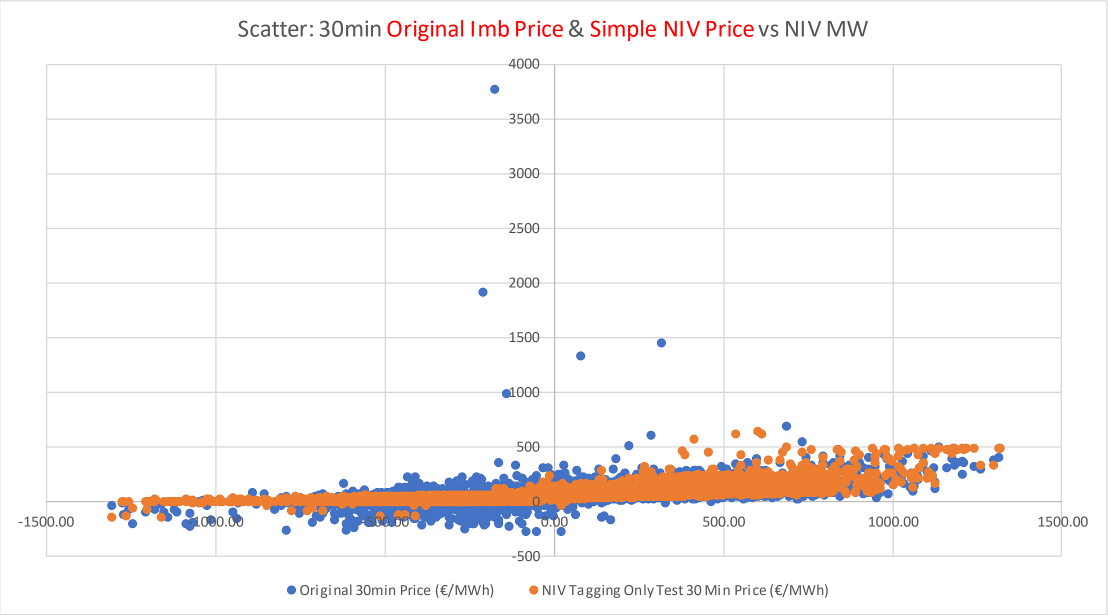


Figure 6

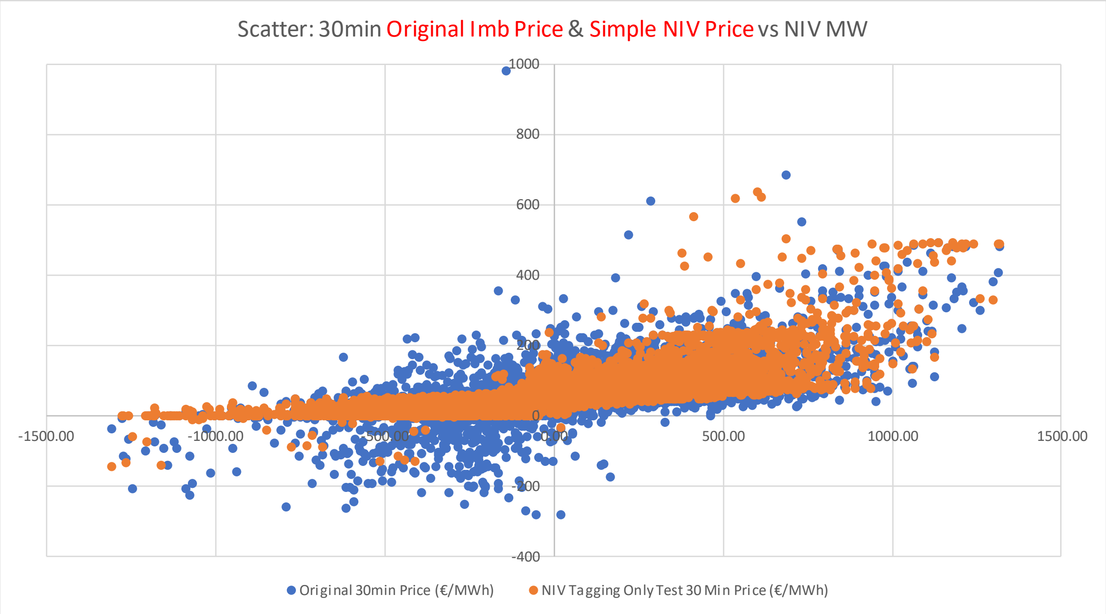


Figure 7 below shows a scatter plot of the difference between the 30-minute prices and the DAM price, against the NIV, with price differences on the vertical axis and the NIV (in MW) on the horizontal axis. Figure 8 is a "zoomed in" version of this scatter plot. The original imbalance prices minus the DAM price are the blue dots and the Simple NIV prices minus the DAM price are the orange dots.

When the NIV is positive the imbalance price would generally be expected to be higher than the DAM price, and when the NIV is negative the imbalance price would generally be expected to be lower than the DAM price. Therefore we would expect most of the dots in these graphs to be in the upper-right and lower-left quadrants.

The most concerning thing in these scatter plots is the number of blue dots in the upper-left quadrant (some of which are very high). Each of these blue dots represents a half-hour where the original imbalance price was higher than the DAM price when the NIV was negative (i.e. the market was long).

Figure 7

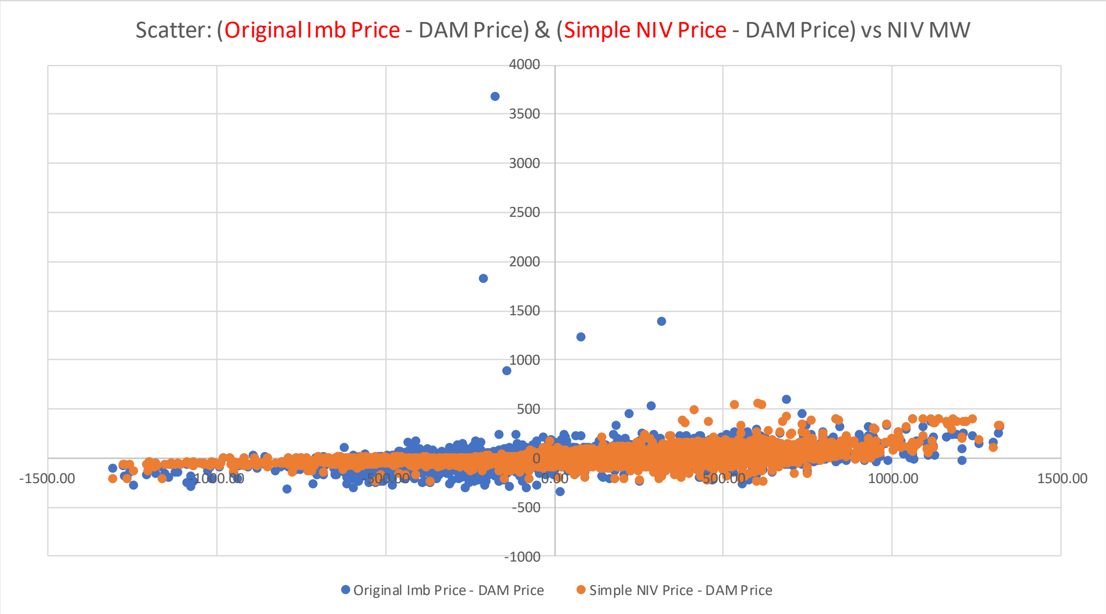
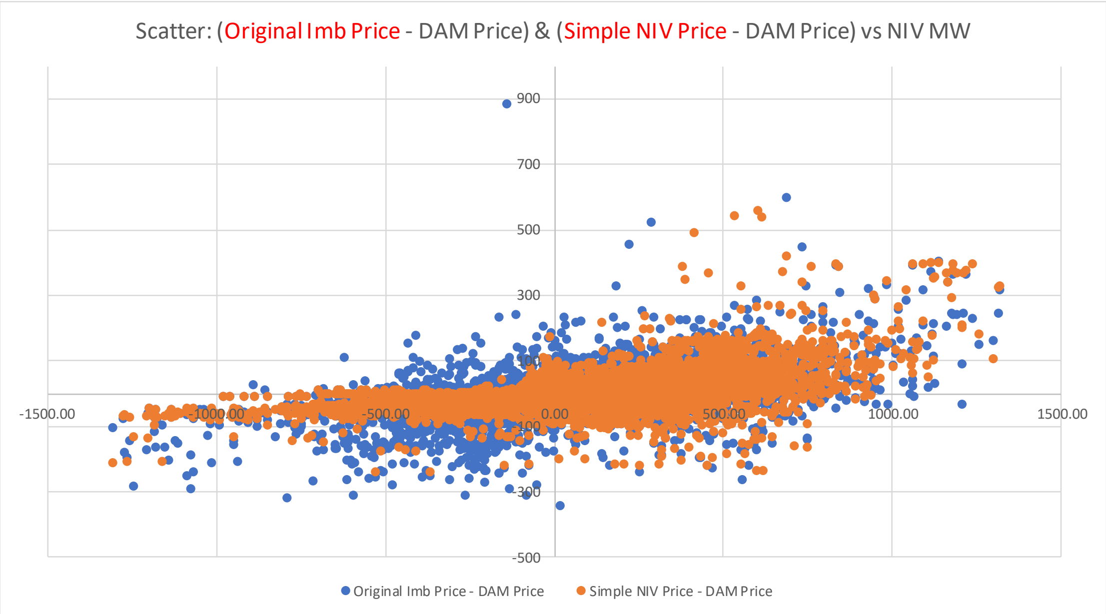


Figure 8



Regression Analysis

Regression analysis was carried out on the 30-minute original imbalance prices and the 30-minute Simple NIV prices to determine how much of the variation in both sets of prices was explained by the following independent variables:

- NIV;
- System Demand; and
- Wind Generation.

The results are outlined in detail in the APPENDIX: DETAILED ANALYSIS OF SIMPLE NIV TAGGING and the summary results are shown in Table 3 below. In summary:

- The NIV, the system demand and wind generation all explain some of the variation in the original imbalance price;
- Of the three independent variables, the NIV is the most important in explaining variation in the original imbalance price;
- The NIV, the system demand and wind generation all explain some of the variation in the Simple NIV price;
- Of the three independent variables, the NIV is the most important in explaining variation in the Simple NIV price;
- The adjusted R Square values of 0.261 and 0.523 for the regressions against the original imbalance price and the Simple NIV price respectively, when all three independent variables are included, indicate that twice as much variation in the Simple NIV price, compared to the original imbalance price, is explained by these three independent variables.

Table 3

	Original Imbalance Price	Simple NIV Price
Adjusted R-Square	0.261	0.523
P-value: NIV	0.00	0.00
P-value: System Demand	0.00	0.00
P-value: Wind Generation	0.00	0.00

Regression analysis was also carried out on:

- The difference between the original imbalance price and the DAM price against the NIV; and
- The difference between the Simple NIV price and the DAM price against the NIV.

The summary results are shown in Table 4 below. At a high level, the NIV explains more than twice as much of the variation in the difference between the Simple NIV price and the DAM price, than the variation in the difference between the original imbalance price and the DAM price.

Table 4

	Original Imbalance Price minus DAM Price	Simple NIV Price minus DAM Price
Adjusted R-Square	0.142	0.309
P-value: NIV	0.00	0.00

Analysis of the imbalance price against the Day Ahead Market price and the NIV

In this section the imbalance prices over the course of the day are compared with the DAM prices and the NIV. Generally, when the NIV is positive the imbalance price would be expected to be higher than the DAM price, and conversely when the NIV is negative the imbalance price would be expected to be lower than the DAM price.

The figures below show the average profiles over the entire period from 1st October 2018 to 28th February 2019. In Figure 9 the original imbalance price is compared with the DAM price and the NIV, in Figure 10 the Simple NIV price is compared with the DAM price and the NIV, and in Figure 11 the difference between both the original imbalance price and the Simple NIV price and the DAM price is compared with the NIV. Generally, when the NIV is positive the imbalance price minus the DAM price would be expected to be positive, and conversely when the NIV is negative the imbalance price minus the DAM price would be expected to be negative.

The averaged profiles below show that the averaged original imbalance prices tend to be below the DAM price overnight, even though the averaged NIV is positive in most half hours overnight. The average Simple NIV price is closer to what would be expected overnight, as it is above the DAM price. Both the original imbalance prices and the Simple NIV prices are lower than the DAM price over the peak hours despite the fact that the NIV is positive. Again this is not as expected but there have been instances of very high imbalance prices over these hours and this has likely sent a signal back to the DAM. It should be noted that averaging effects will have a significant effect within these average profiles.

10 individual days are examined in more detail in the subsequent pages.

Figure 9

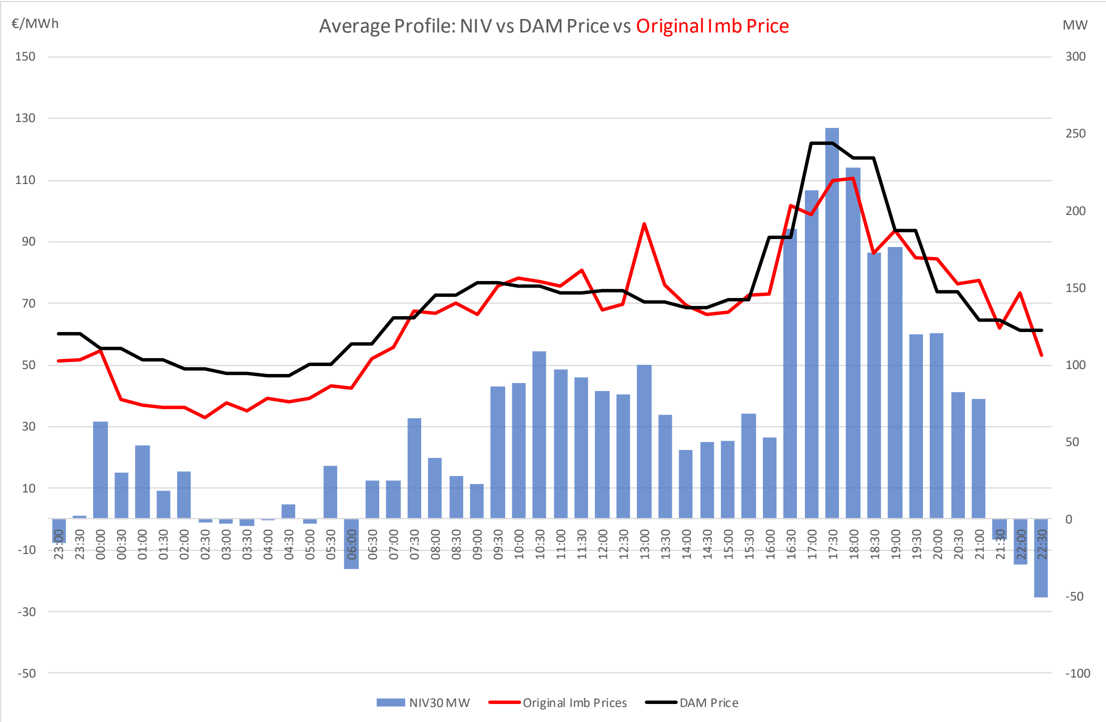


Figure 10

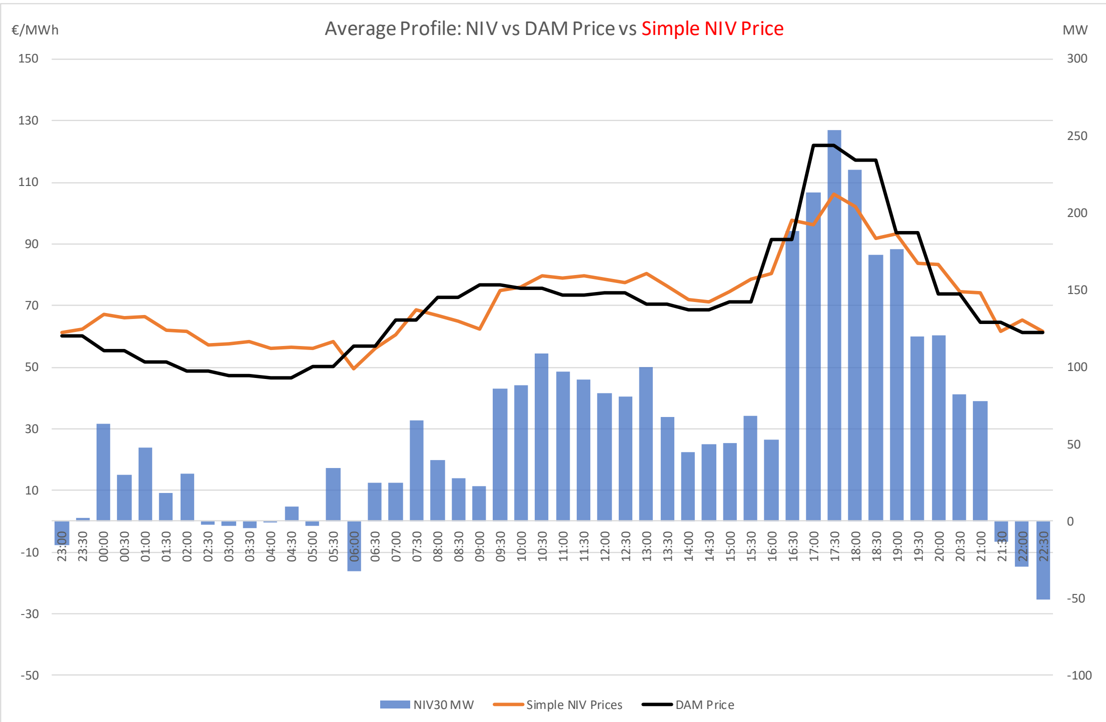
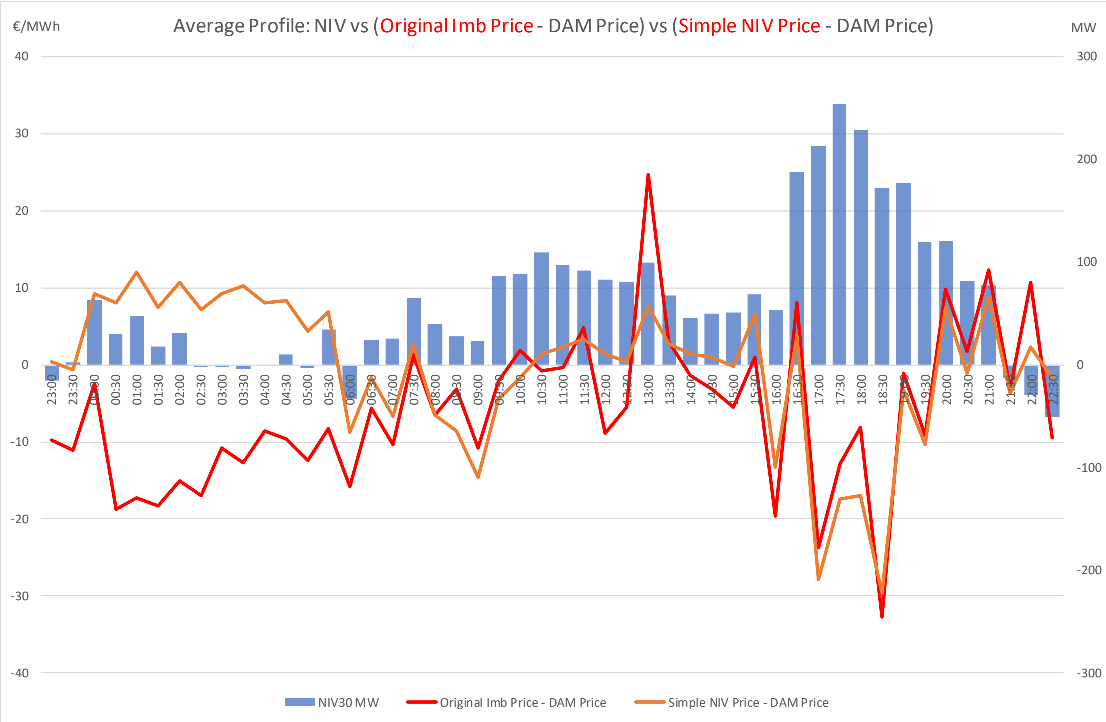


Figure 11

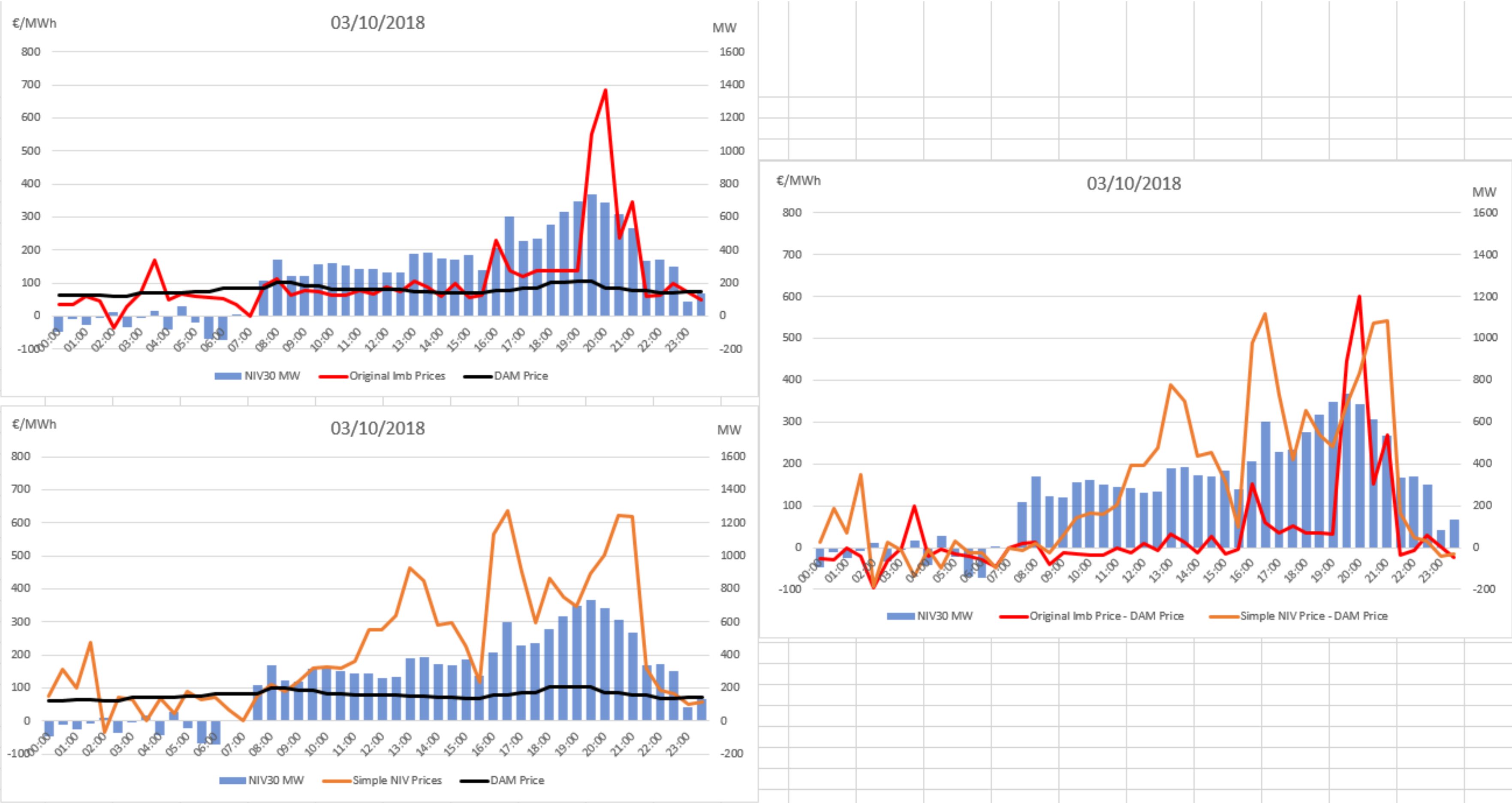


For the 10 individual days that are examined in the following pages:

- the graph in the upper left shows the original imbalance price (red line) against the DAM price (black line) and NIV (blue columns);
- the graph in the lower left shows the Simple NIV price (orange line) against the DAM price (black line) and NIV (blue columns); and
- the graph on the right shows difference between the original imbalance price and the DAM price (red line) & the difference between the Simple NIV price and the DAM price (orange line) against the NIV (blue columns).

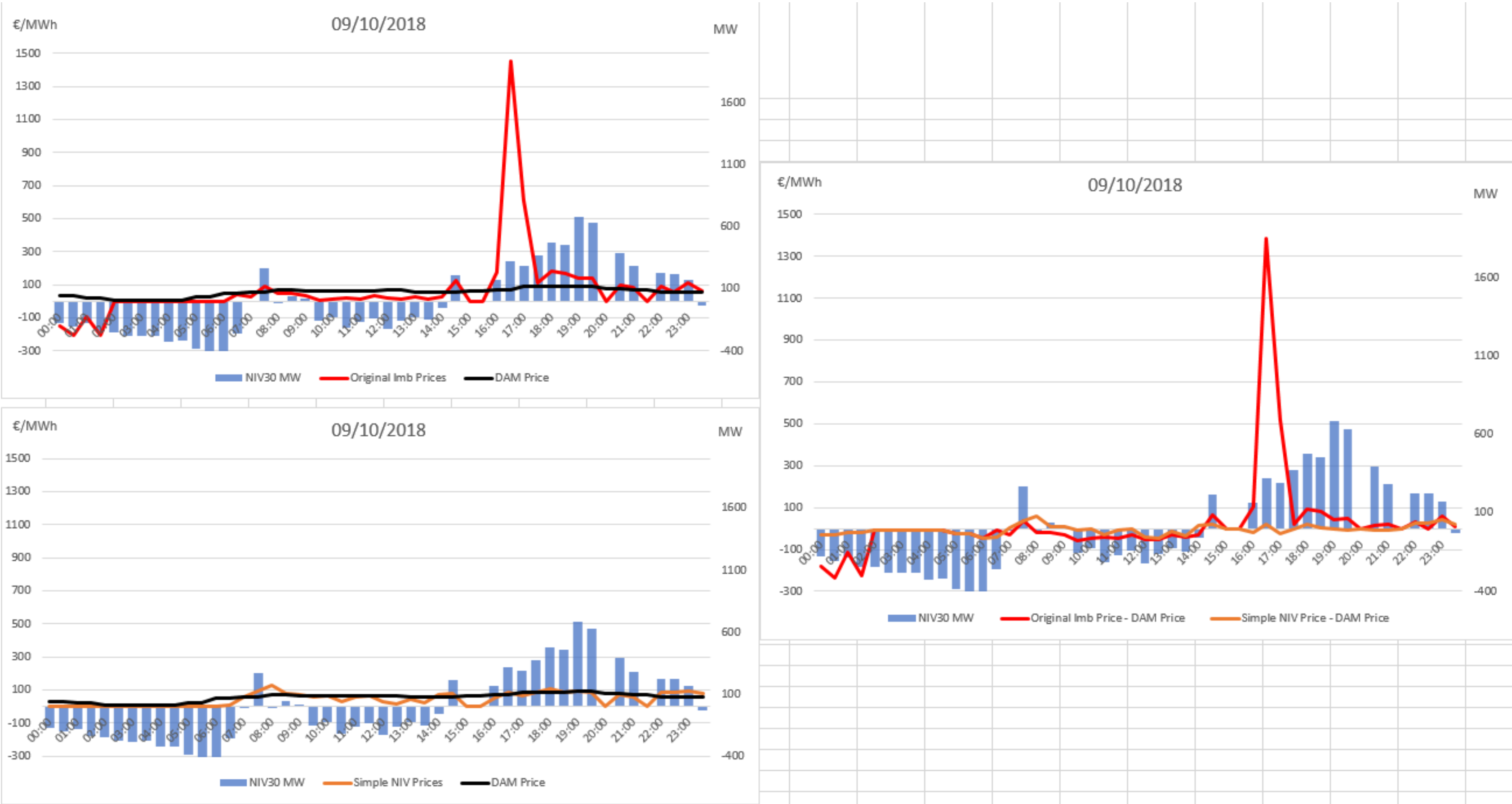
03/10/2018: The first RO difference payment event occurred on 03/10/2018, when the imbalance price went over 500 €/MWh. The graphs below show that there would have been similar RO difference payment events on this day if simple NIV tagging was used to set the imbalance price. The Simple NIV price doesn't go as high but it does go over 500 €/MWh, and for more half hours. Note that this is the only day on which RO difference payments would have occurred if Simple NIV tagging was used.

Figure 12



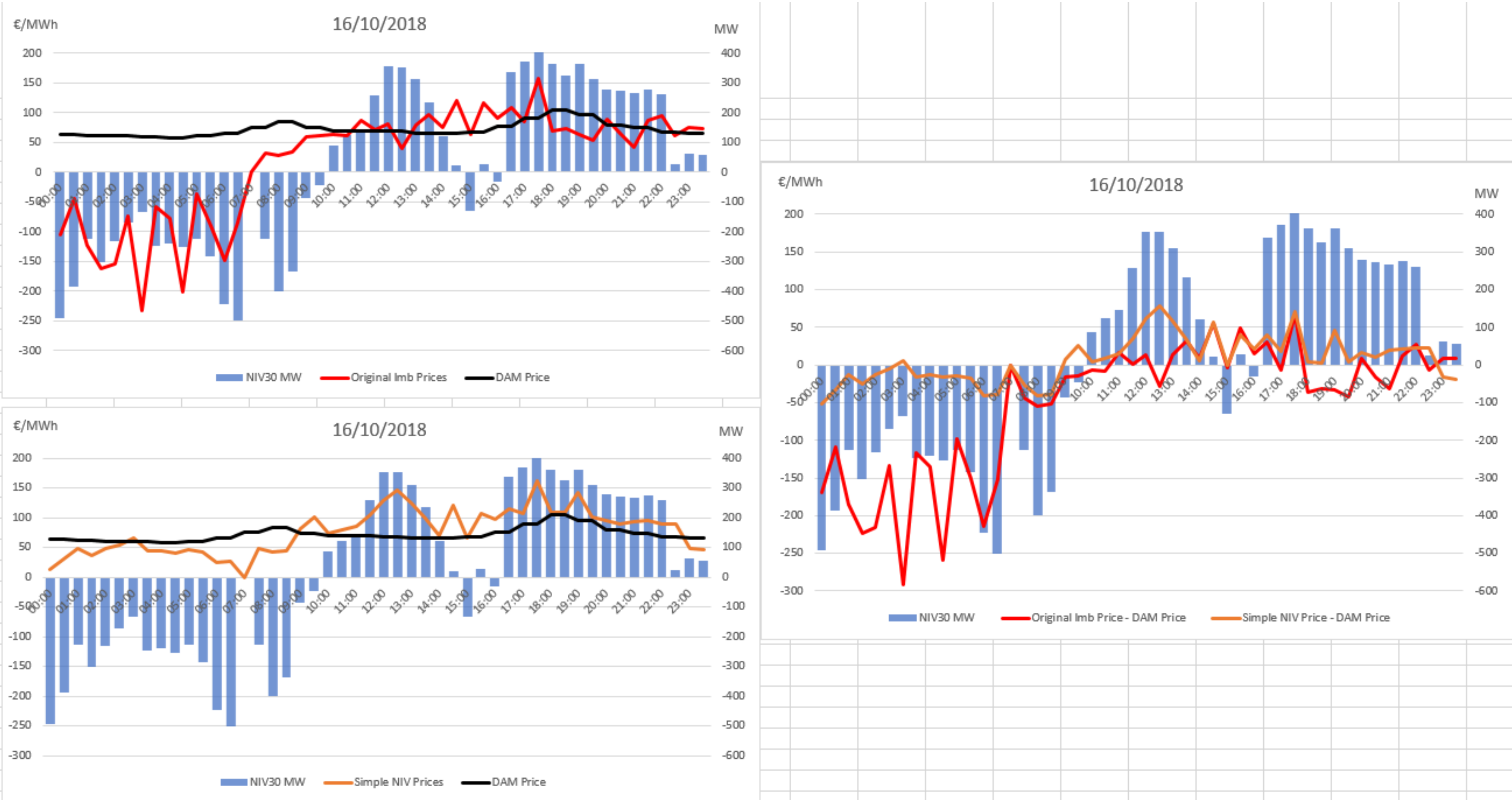
09/10/2018: The second RO difference payment event occurred on 09/10/2018, when a peaking unit in Northern Ireland set the imbalance price at nearly 1,500 €/MWh. The graphs below show that this RO difference payment event would not have occurred on this day if Simple NIV tagging was used to set the imbalance price. The Simple NIV price is close to the DAM price all day. This makes sense as the NIV was not extreme on this day and the high imbalance price was set due to an Amber Alert in Northern Ireland rather than significant overall shortage on the system.

Figure 13



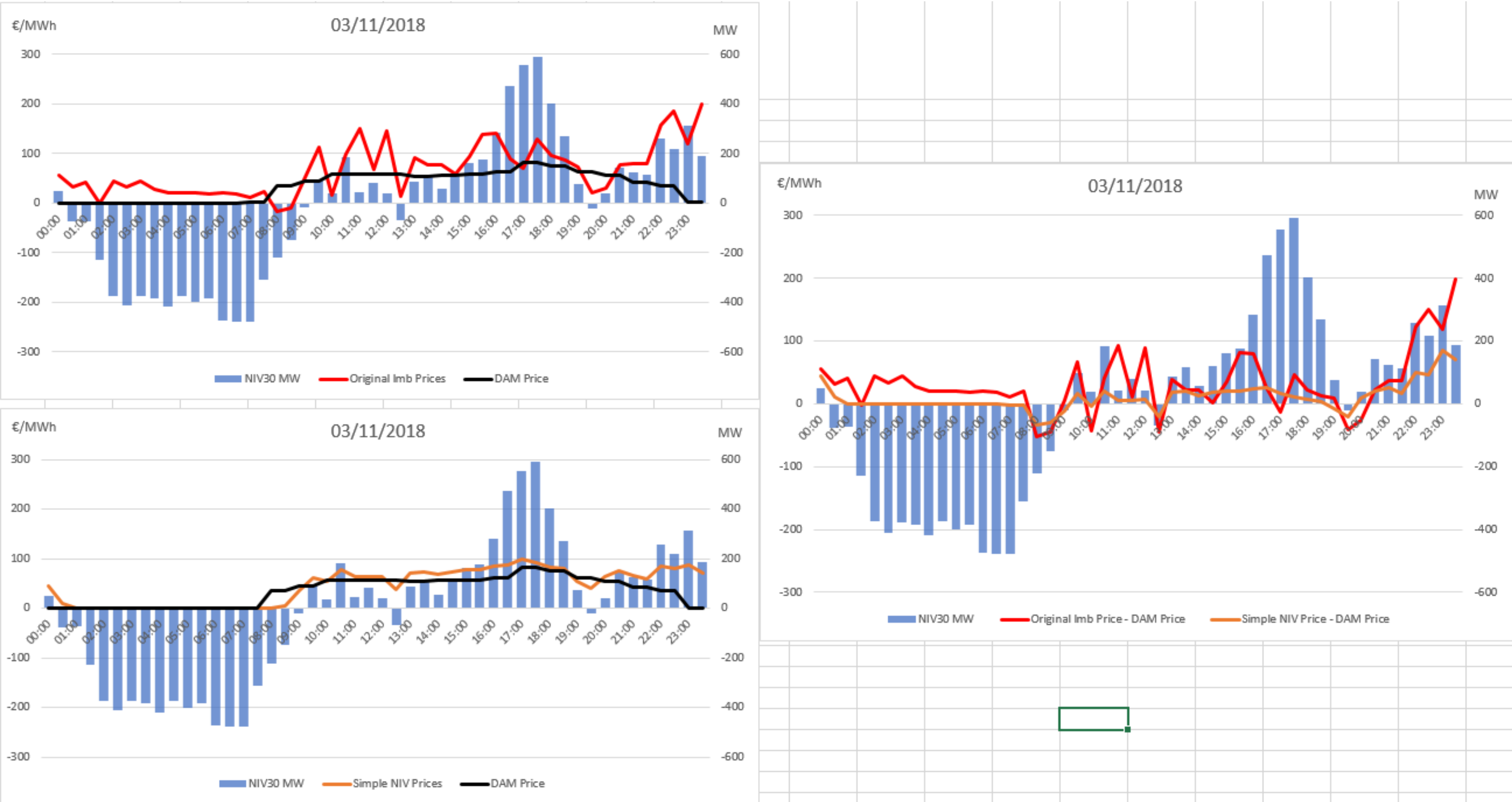
16/10/2018: On 16/10/2018 significant negative prices are seen in the original imbalance prices overnight. The Simple NIV prices behave as expected overnight and are below the DAM price, but they do not go negative. Later in the day the original imbalance prices go below the DAM price despite the fact that the NIV is positive – this does not occur with the Simple NIV price as they are higher than the DAM price.

Figure 14



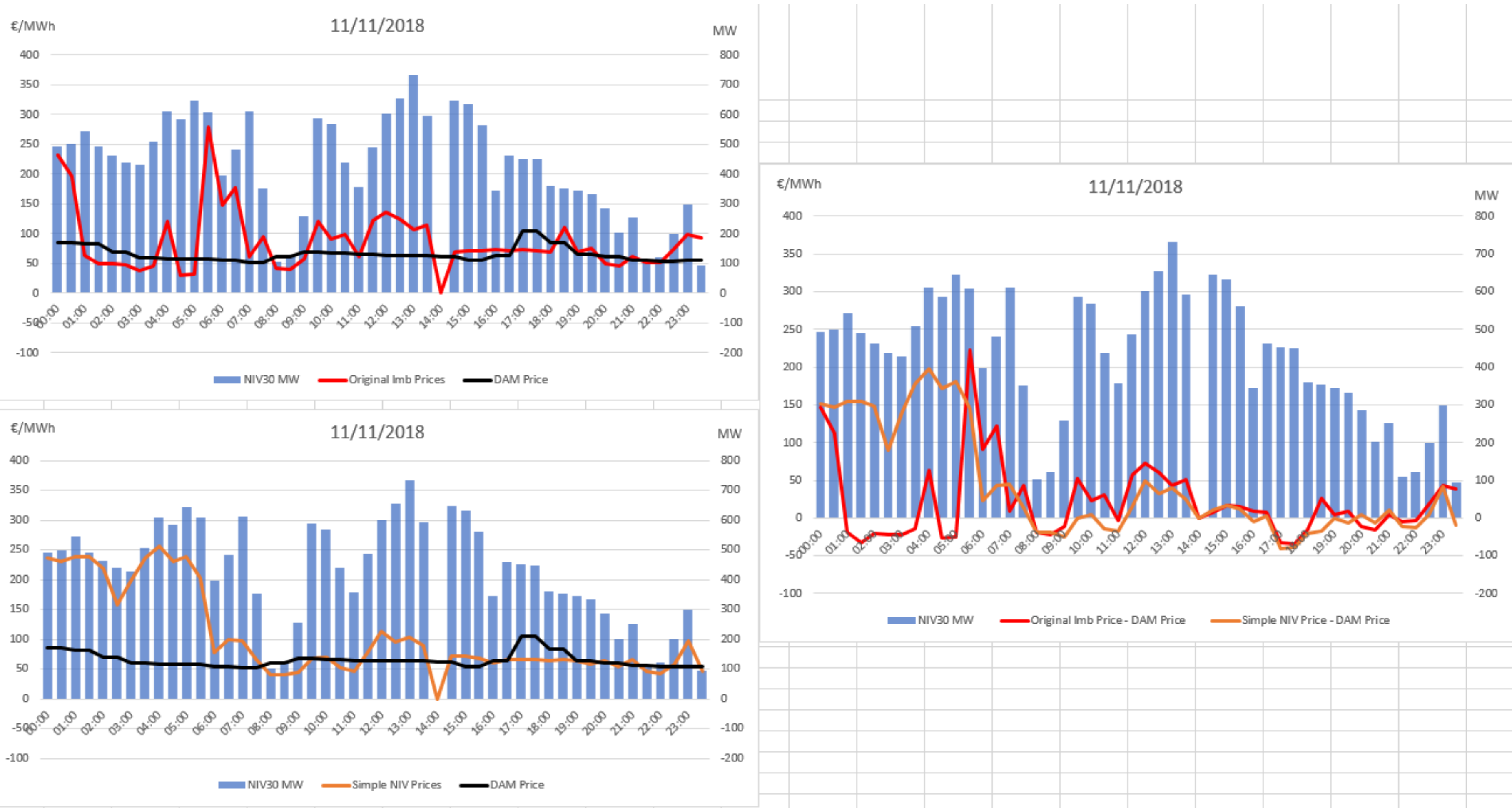
03/11/2018: On 03/11/2018 the original imbalance prices stay above the DAM price overnight despite the fact that the NIV is negative. It should be noted here that the DAM price overnight is 0 €/MWh and this was probably based on the expectation of negative imbalance prices. The Simple NIV price also goes to 0 €/MWh overnight. In the final hours of the day the DAM price returns to 0 €/MWh but the original imbalance prices go to approximately 200 €/MWh. The Simple NIV prices also increase but stay below 100 €/MWh.

Figure 15



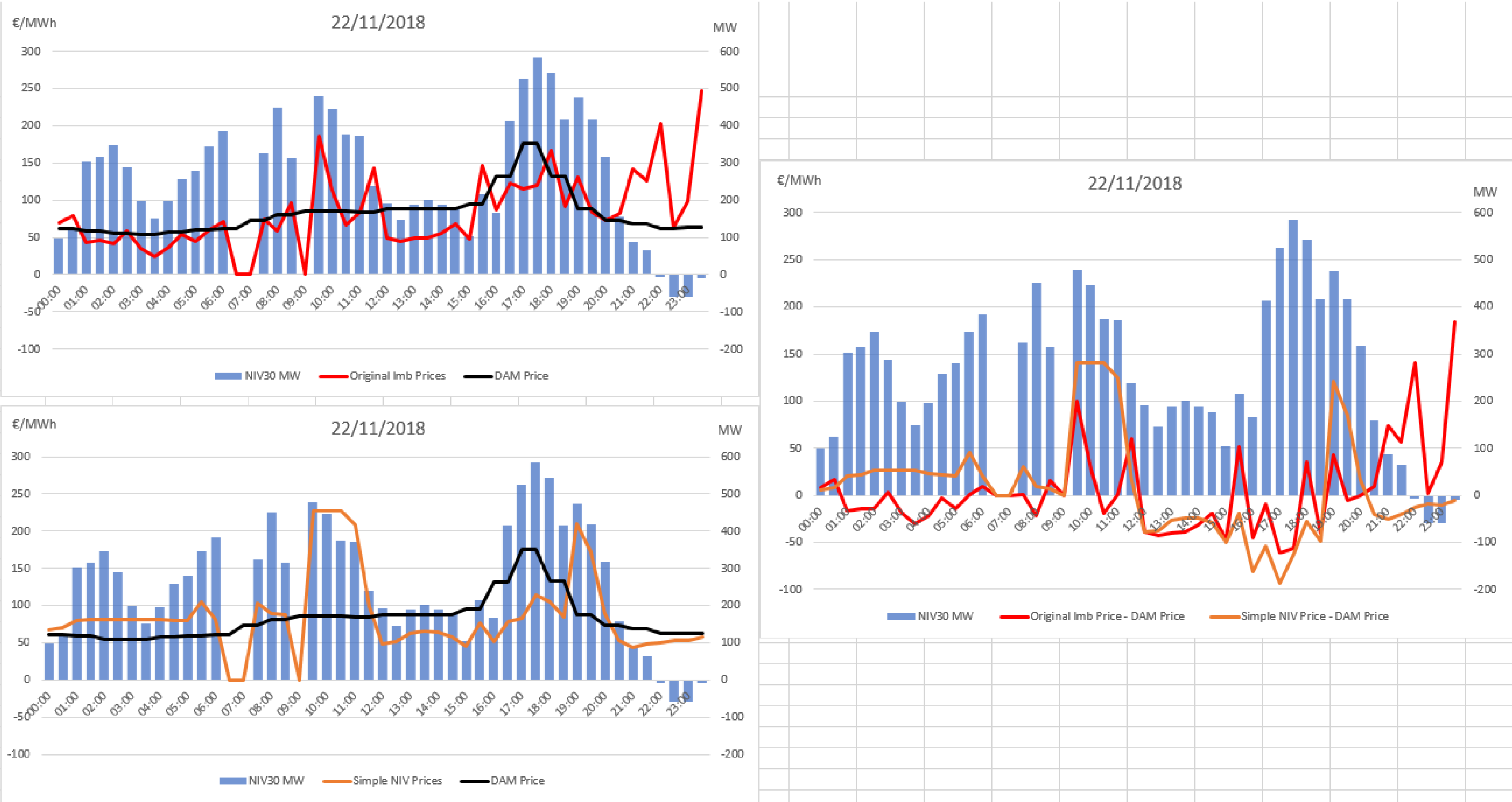
11/11/2018: On 11/11/2018 the original imbalance prices went below the DAM price overnight despite the fact that the NIV was significantly positive (approximately 500MW). In contrast, the Simple NIV prices are significantly higher than the DAM price overnight, which is more line with what would be expected.

Figure 16



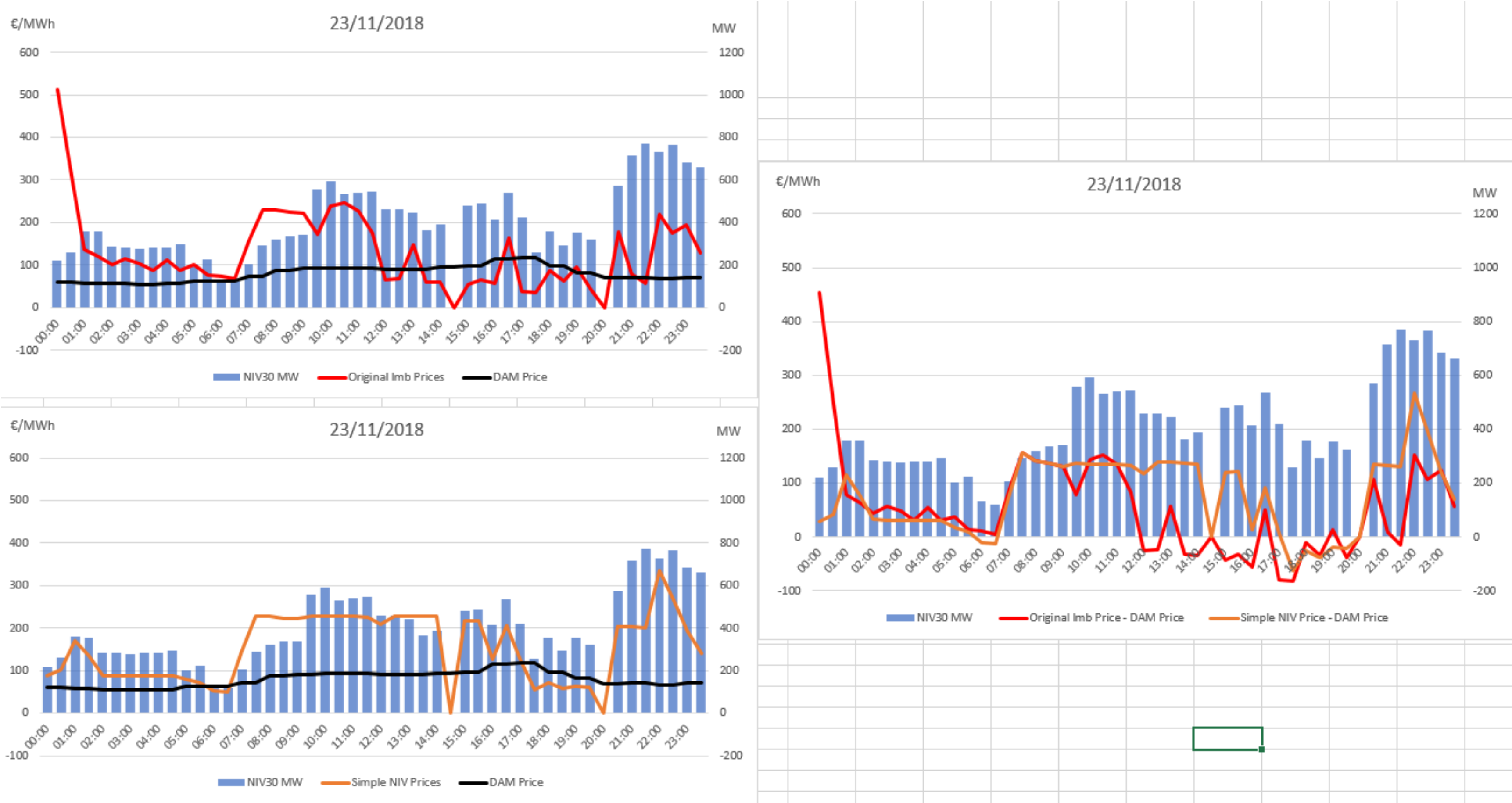
22/11/2018: On 22/11/2018 the original imbalance price jumps to 250 €/MWh at 23:30, despite the fact that the NIV is actually negative. The Simple NIV prices are below the DAM price in this period.

Figure 17



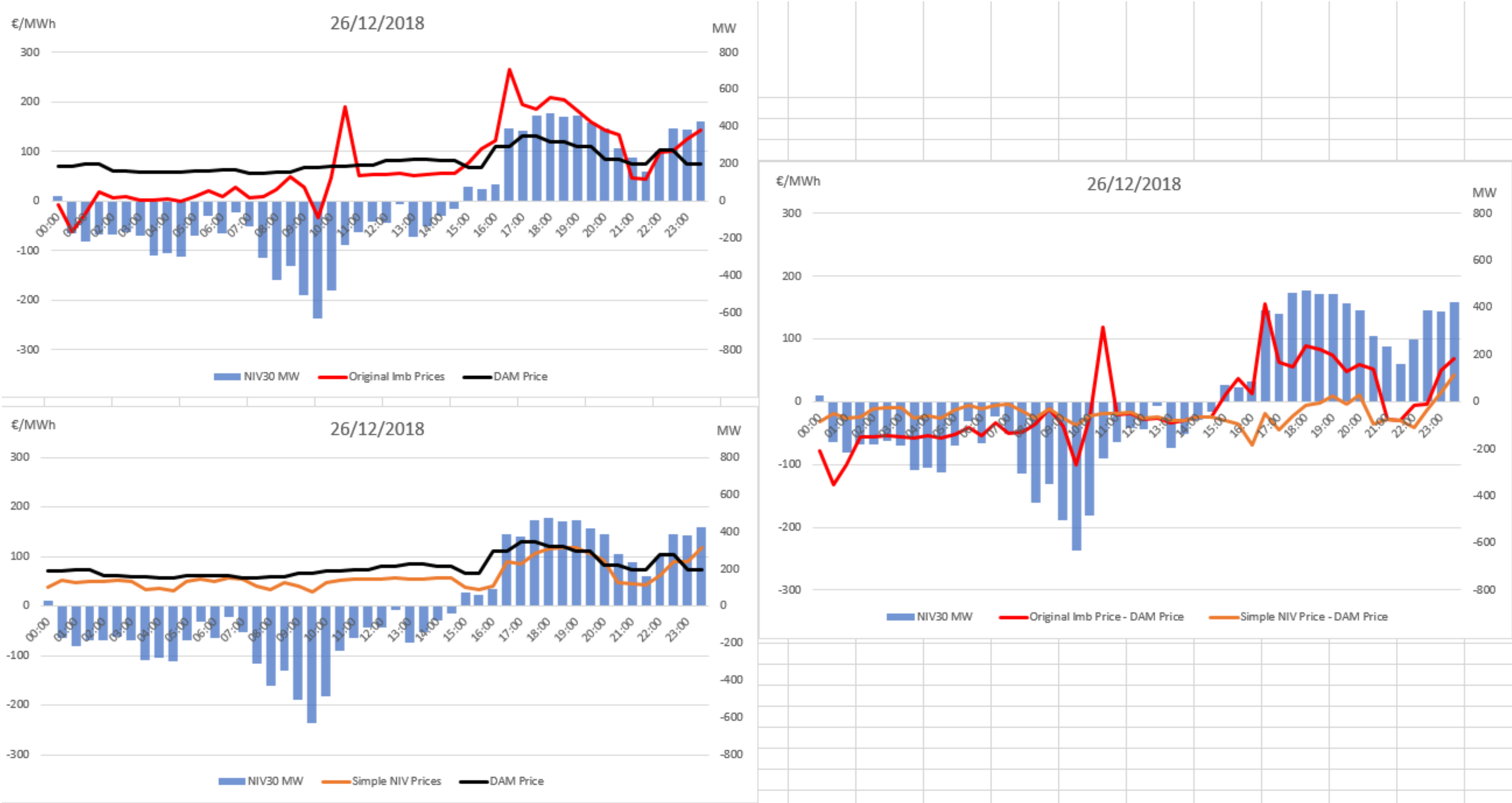
23/11/2018: The third, albeit smaller, RO difference payment event occurred on 23/11/2018 when the original imbalance price went to 514 €/MWh at 00:00. The NIV was positive at this time but was only approximately 200MW. The Simple NIV price was approximately 100 €/MWh at this time. The original imbalance price then goes below the DAM price at 12:00 and 14:00 despite that fact that the NIV is approximately 400MW at these times. The Simple NIV price stays above the DAM price in these periods.

Figure 18



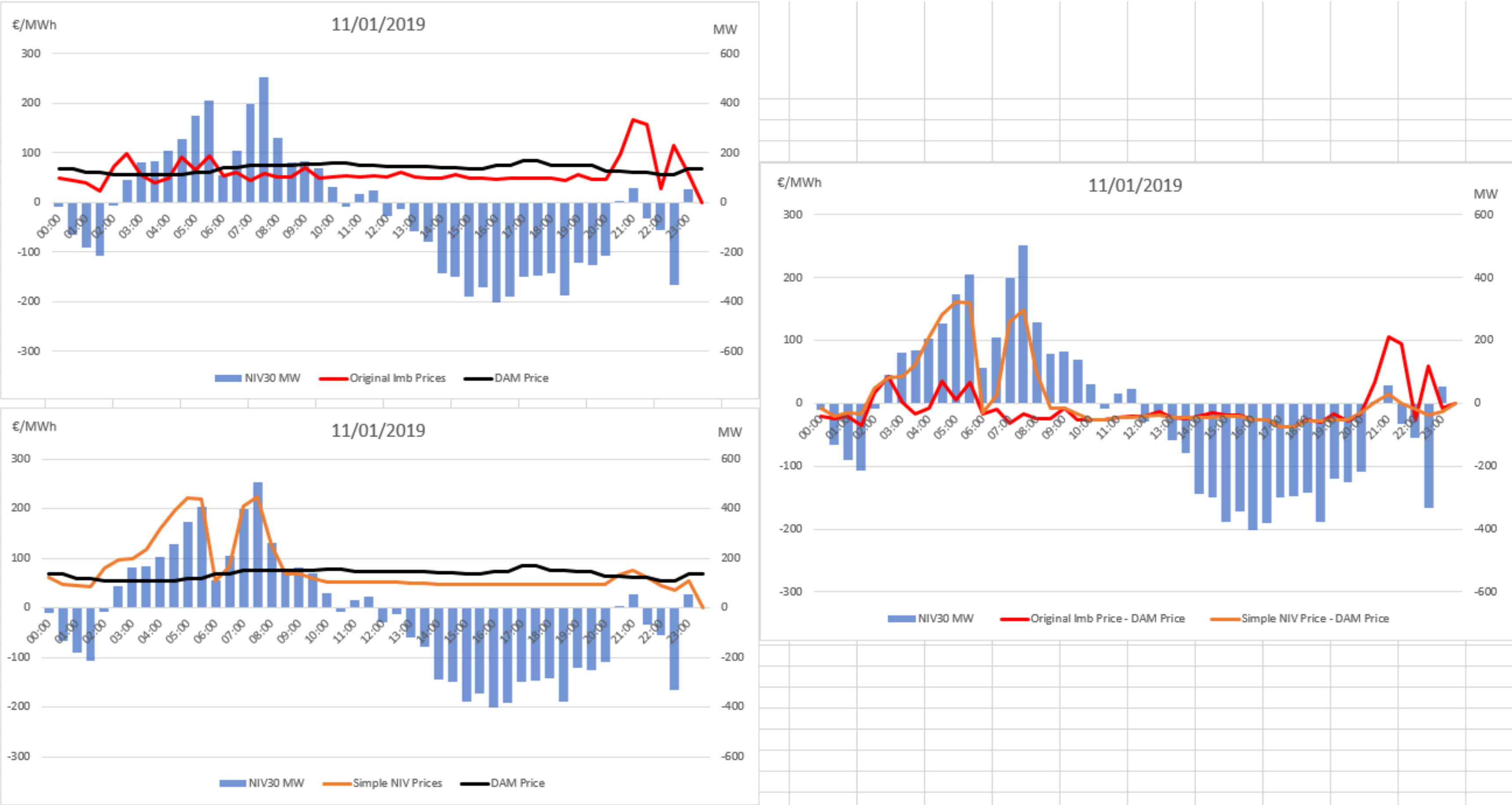
26/12/2018: This day is examined as it is one of the only days where the original imbalance price behaves more in line with expectations than the Simple NIV price. The NIV is approximately 400MW over the peak hours and the original imbalance price is higher than the DAM price as expected while the Simple NIV price stays below the DAM price. Even on this day however the original imbalance price jumps to 200 €/MWh for one half hour only at 11:00 when the NIV is negative.

Figure 19



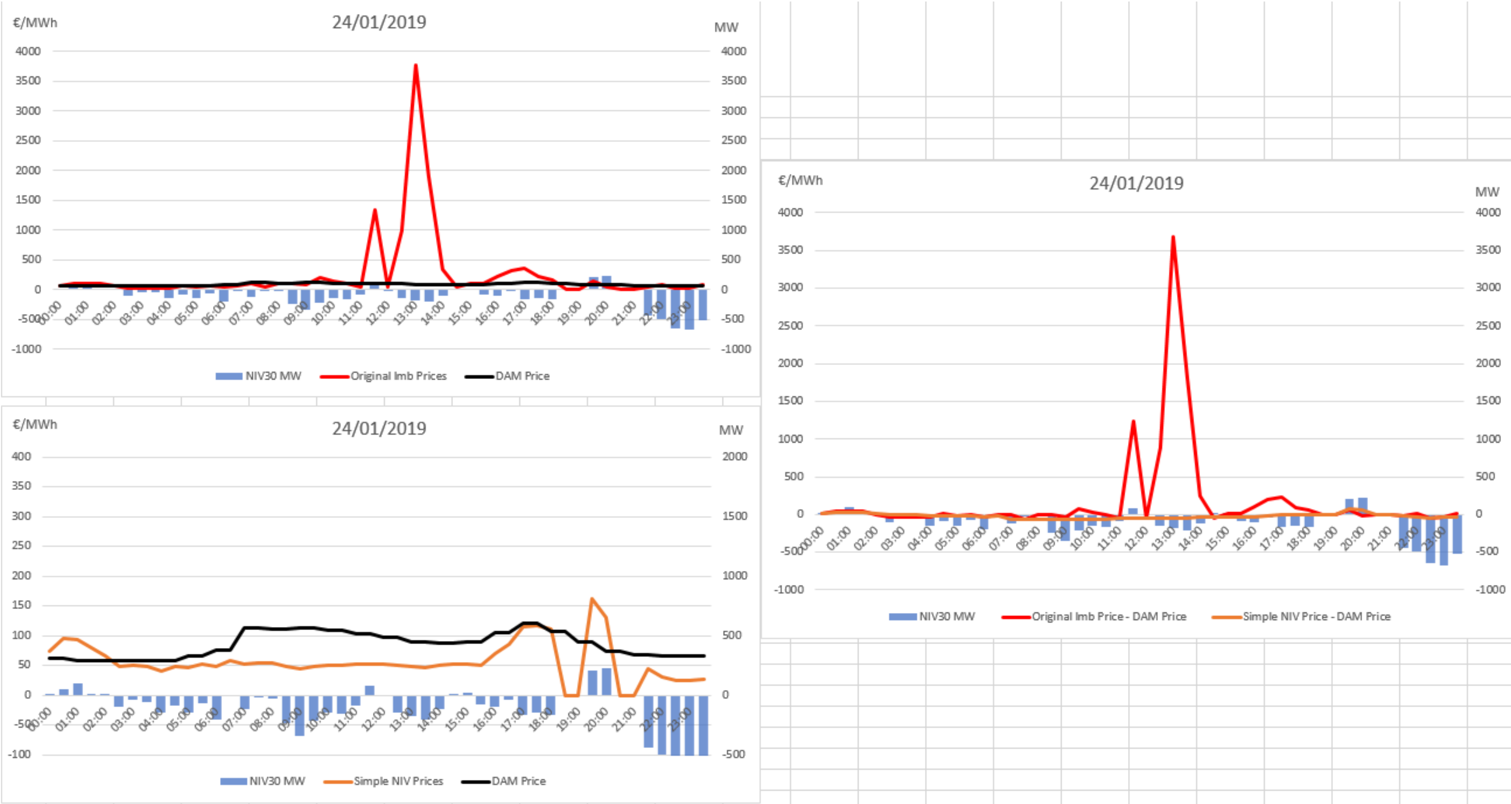
11/01/2019: On 11/01/2019 the Simple NIV price follows the expected pattern very well. It is slightly below the DAM price from 00:00 to 02:00 while the NIV is moderately negative, then increases over the DAM price in line with the NIV going positive, then drops back below the DAM price when the NIV goes negative. At 21:00 it rises above the DAM price for one period, exactly when the NIV goes positive for one period. The original imbalance price does not follow the expected pattern as well.

Figure 20



24/01/2019: The fourth, and most significant by far, RO difference payment event occurred on 24/01/2019 when the original imbalance price went to 3,773.69 €/MWh. The high price was set at 13:00 by an expensive peaking unit in Northern Ireland due to constraints on south-to-north flows on the Tie-Line and the NIV was actually negative at this time (i.e. the market as a whole was long). The Simple NIV price follows the expected pattern closely and is below the DAM price for most of the day, only going above the DAM price when the NIV goes positive.

Figure 21



Conclusion

The analysis in this section and APPENDIX: DETAILED ANALYSIS OF SIMPLE NIV TAGGING shows that:

- Simple NIV tagging removes most of the extremely high imbalance prices;
- Simple NIV tagging removes a significant number of the negative imbalance prices;
- The average imbalance price produced by Simple NIV tagging is actually higher than the average original imbalance price, and is higher than the average DAM price (while the average original imbalance price is lower than the average DAM price);
- The imbalance prices produced by Simple NIV tagging are less volatile than the original imbalance prices, while still retaining significant volatility;
- The imbalance prices produced by Simple NIV tagging are explained to a significantly greater degree (i.e. approximately twice as much) by the NIV, System Demand and Wind Generation. These prices should thus be easier for market participants to forecast; and
- The imbalance prices produced by Simple NIV tagging act more in line with what would be expected given the DAM price and the NIV.

2.4 Consultation Questions regarding Simple NIV tagging

The SEM Committee is proposing to remove all System Operator Flags and Non-Marginal Flags from the imbalance pricing algorithm i.e. to use Simple NIV tagging in the Balancing Market.

The SEM Committee is of the view that Simple NIV tagging meets the I-SEM High Level Design, the I-SEM Detailed Design and the I-SEM market power mitigation decision; and that the modelling results show that pricing outcomes under Simple NIV tagging are preferable, given market fundamentals, to the pricing outcomes under the current methodology.

Respondents are asked to consider the following questions and to provide answers in their responses to this consultation.

2.1) Do you support this Simple NIV tagging option and its implementation in the SEM?

2.2) Do you have any concerns regarding moving to Simple NIV tagging in the Balancing Market, including the risk of unintended consequences? If so, please explain these concerns.

2.3) Do you agree or disagree that Simple NIV tagging meets the I-SEM High Level Design, the I-SEM Detailed Design and the I-SEM market power mitigation decision? If you disagree, please explain why.

2.4) Do you agree or disagree with SEM Committee's assessment that the pricing outcomes under Simple NIV tagging are preferable, given market fundamentals? If you disagree, please explain why.

3. OPTION TWO: REMOVAL OF DIFFERENCE CHARGES WHERE OPERATIONAL CONSTRAINTS ARE BINDING

3.1 Introduction

Since Go-Live (notably on 9th October 2018 and 24th January 2019) circumstances have arisen whereby certain Generator Units cannot be dispatched up by the System Operators due to the presence of an Operational Constraint on the system. In these instances, the Generator Units may be subject to Difference Charges where the imbalance price is higher than the strike price.

As part of TSC Modifications Working Group discussions on Modification proposal 32_18 SEMO proposed an alternative given the difficulties foreseen from a system implementation perspective with the original modification. The alternative proposed by SEMO has the aim to remove the exposure to Difference Charges of Generator Units whose scheduled output cannot be increased due to an Operational Constraint.

Currently, the System Service Flag (FSS) is set to zero, and thus removes exposure to Difference Charges, for units that are bound by the Replacement Reserves constraint only. The proposal suggested by SEMO at the TSC Working Group seeks to broaden the circumstances under which the FSS would be set to zero. This approach does not change the imbalance price and would not prevent prices above the strike price being calculated; however, it would change the implications of these prices in downstream capacity settlement.

This proposed option would be implemented by setting the System Service Flag to zero on a broader set of constraints that limit an increase in a unit's output, these are:

- **All Operating and Replacement Reserves (except Negative Reserves)** – currently Replacement Reserve only;
- **S_MWR_ROI, and S_MWR_NI** – when transfers from Ireland to Northern Ireland and vice versa are at a maximum;
- **S_SNSP_TOT** – when the System Non-Synchronous Penetration (SNSP) level is equal to the SNSP limit;
- **S_RoCoF** – ensures Ireland and NI power systems do not exceed Rate of Change of Frequency (RoCoF) limits;
- **S_MWMAX_NI_GT, S_REP_NI, S_REP_ROI, and S_MWMAX_ROI_GT** – combined MW output of OCGTs must be less than set MW number in Ireland and NI. This is required for replacement reserve in NI and Ireland;
- **S_MWMAX_CRK_MW , and S_MWMAX_STH_MW** – generation restriction in the Cork area and Southern Region; and
- **other constraints that may be added from time to time**.

Under this proposed option, units bound by a binding constraint would be flagged with a System Service Flag. This includes units that are included in the constraints that are available to deliver but OFF at the time. Units that are not available to deliver and/or not bound by the constraints listed above would not be flagged with a System Service Flag and thus would still be exposed to Difference Charges if the imbalance price went above the Strike Price.

In terms of implementation, should this option be supported in the SEM Committee decision following this consultation, a TSC modification (Appendix N: Flagging and Tagging) would need to be progressed through the Modification process together with a revision to the TSOs' Methodology for Determining System Operator and Non-Marginal Flags. Upon approval of a modification the decision could be implemented relatively quickly through configuration settings in the Central Market Systems, avoiding the longer timelines needed for system changes.

The initial steps taken as described in section 1.2 of this paper excludes System Operator Flags relating to certain constraints from the imbalance pricing process in order to reduce the possibility of further extreme pricing events, while further approaches are investigated and developed (including this consultation). These changes may reduce the likelihood of further extreme RO events like that which occurred on the 24th January 2019.

3.2 Description of issue

There have been several instances since Go-Live of Generator Units which hold Reliability Option (RO) obligations facing Difference Charges (where the imbalance price is higher than the RO strike price) while being unable to be dispatched up by the System Operators due to the presence of an Operational Constraint on the system. These affected units were in merit (in the balancing energy market), and available but were not delivering energy up to their RO MW level so were exposed to Difference Charges. These events occurred notably on 9th October 2018 and 24th January 2019.

For instance, on the 24th January 2019 Reliability Option holders across the island incurred difference charges totalling €7.023m. An amount of €1.605m was due to be paid to suppliers due to the imbalance price exceeding the strike price during that day. Based on this day there was a surplus in the socialisation fund of €5.418m between what was received and what was due to be paid out.

On the 9th October 2018 Reliability Option holders across the island incurred difference charges totalling €1.223m. An amount of €1.011m was due to be paid to suppliers due to the imbalance price exceeding the strike price during that day. Although not of the same scale as on the 24th January 2019, once again there was a surplus in the socialisation fund of €0.212m between what was received and what was due to be paid out.

The occurrence of these events is due to the interaction of a number of different factors, these include system characteristics, market design features and out-turn prices in specific trading periods. These key factors include:

- CRM design feature of the RO Market Reference Price (MRP) being split across the DAM, IDM and the BM;
- Operational Constraints on the system preventing certain Generator Units being dispatched up;
- Operational Constraints on the system interacting with the formation of the imbalance price; and
- Imbalance price turning out to be higher than the RO strike price.

The high imbalance prices which occurred on 24th January 2019 reached €3,773.69 MWh in one half-hour, even though the SEM overall was long at the time; with the imbalance price set by an expensive peaking unit in Northern Ireland which was initially dispatched out-of-merit for non-energy reasons. These type of events in the energy market interact with the CRM design, with the RO MRP being split across the DAM, IDM and the BM, meaning that a generator unit which could not be dispatched up due to Operational Constraints on the system (even though available) could face Difference Charges based on the imbalance price being above the RO strike price.

On the 24th January 2019 a portion of capacity in Ireland (in merit, available but not delivering energy up to their RO MW level dispatched) faced significant RO difference payments, even though these units could not respond to alleviate the issues on the system that day. Some units in NI were also in merit, available but not dispatched nor providing replacement reserve, and also faced significant RO difference payments.

3.3 Policy Background to this Option

CRM Design Overview

The High-Level Design (HLD) decision paper (SEM-14-085) was clear that an explicit capacity mechanism was required to deliver long term generation adequacy to ensure secure supplies for all-island consumers. The HLD described how the explicit quantity-based CRM would take the form of Reliability Options (RO) issued to capacity providers by a centralised party through a competitive auction. It was described how ROs are where the holder of the option is paid an annual payment in return for the TSO having the right to call on the RO holder to provide energy at a pre-determined strike price. The HLD set out advantages of the RO design in that it offers suppliers a hedge against high energy market prices.

As part of the CRM Detailed Design decision paper 1 (SEM-15-103) the decision was taken to have a single zone for capacity consistent with the single zone energy market. This was also preferable to help mitigate issues in relation to market power and therefore facilitate a more competitive outcome. The decision explicitly stated that the SEM Committee did not intend to introduce locational pricing in the CRM. Furthermore, this decision also decided on the principle of mandatory bidding for existing dispatchable plant within the capacity market.

Furthermore, as part of the CRM Detailed Design decision paper 1 the SEM Committee addressed to some extent concerns raised by capacity providers who may not receive energy payments to offset their difference payment liabilities due to circumstances beyond their control (paragraphs 3.3.79 to 3.3.82). Albeit this was considered predominantly from the perspective of the capacity provider not being sufficiently flexible to respond and therefore recommended to price that risk into their capacity auction bids. However, the SEM Committee did make it clear that capacity providers who are providing reserve or other system services in accordance with TSO instructions will have the relevant part of their Reliability Option commitment settled with reference to their reserves[9]/system services income (para 3.3.80).

Also, within CRM decision paper 1 the SEM Committee confirmed that RO difference payments will be due purely on a price-based trigger, not a scarcity-based trigger. Therefore, if prices rise above the Strike Price for reasons other than scarcity, suppliers will be protected and generators will be subject to difference payments (paragraph 3.3.94). However, in an effort to not place excessive risk on capacity providers, stop-loss limits were imposed to limit the level of Reliability Option difference payments a capacity provider could be exposed to. The stop-loss limits were further developed in CRM Parameters decision

[9] Later SEM Committee publication, clarified this as Replacement Reserve.

paper (SEM-17-022) with decisions being made on both a billing period and annual stop-loss limits being put in place.

In CRM decision paper 1 the SEM Committee decided that the Market Reference Price (MRP) of the RO would be the split market price option. Under this design option capacity providers' ROs are settled on:

- Volumes sold in the DAM at the DAM reference price;
- Volumes sold in intra-day markets at the intra-day MRP(s); and
- Any remaining Reliability Option volume at the BM reference price.

In the event that the sum of capacity provider's DAM and IDM volumes sold exceed its RO volume, DAM volumes are taken into account first, and then each IDM trade (or part trade) progressively in the order in which they are executed, until the volume of sales equals the RO volume.

During the CRM detailed design phase it became apparent that there was a need to recognise that in practice the transmission system is not indifferent to the location of capacity required to meet security of supply requirements across the island. While the capacity market is designed on the basis of a single zone, locational constraints have been introduced[10] specifically to the capacity auction with the introduction of locational capacity constraint area minimum MW requirements. The sole purpose of this is to ensure a minimum capacity is procured in the capacity auction in specific areas (currently Dublin and Northern Ireland) due to the presence of significant constraints on the all-island transmission network. With this auction format exception the capacity market is designed as a single zone for capacity, consistent with the single zone approach for the SEM energy markets.

The Capacity Remuneration Mechanism has been designed based on the High Level Design principles with the overall design receiving State Aid approval in November 2017.

Policy Background to this Option

In CRM Detailed Design decision paper 1 (SEM-15-103)[11] in paragraph 3.3.97 the SEM Committee recognised that capacity providers directed to provide operating reserve or other DS3 System Services should not be inappropriately disadvantaged when acting on instruction of the TSO. This detailed design decision was reflected through the Rules Working Group stage (meeting 13 held on 15th December 2016) to capture the SEM Committee's intention.

[10] CRM Locational Issues Decision Paper (SEM-16-081)
[11] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-15-103%20CRM%20Decision%201_0.pdf

In the CRM design developed through the Rules Working Group the System Service Flag (FSS) was introduced to remove the exposure to Difference Charges from Generator Units whose scheduled output was limited by an Operational Constraint and where this constraint relates to the provision of Replacement Reserve.

If a unit is contributing to a binding operational constraint for the provision of Replacement Reserve, in any Imbalance Pricing Period within an Imbalance Settlement Period, this approach sets the value of FSS for that Imbalance Settlement Period equal to 0. Therefore, units which the TSOs have not assigned a FSS equal to 0 are still exposed.

This option, which originates from a proposal suggested by SEMO at the TSC Working Groups, seeks to broaden the circumstances under which the FSS would be set to zero. It would extend the System Service Flag to all constraints that limit an increase in output on a unit. The proposed approach includes all Operational Constraints that would limit the increase in output of Generator Units (including DSUs) and would not be confined to the current Replacement Reserve constraints i.e. it would include all operating reserves, replacement reserves, all MW and MWR limit constraints, SNSP, etc.

The justification for this proposed change is to alleviate those units with Awarded Capacity under the Capacity Market who cannot be dispatched up by the TSOs due to the presence of an Operational Constraint on the system from incurring uncovered difference payments where the imbalance price is higher than the strike price.

The concern raised by Market Participants at the Modification Working Groups in relation to this issue is that, in their view, without making this change parties may be unable to manage their exposure to Difference Charges during Imbalance Settlement Periods in which the TSOs cannot increase the output of Generator Units due to binding Operational Constraints. However, these events would be expected to be significantly lower in both likelihood and severity should the measures in Option 1 (Simple NIV tagging) be implemented together with the existing measure already taken (Mod_09_19 outlined in section 1.2).

This modification proposal would remove the exposure to Difference Charges of Generator Units whose scheduled output cannot be increased due to an Operational Constraint. This would cover all Operating and Replacement Reserves (except Negative Reserves) that limit an increase in a unit's output, these are:

- **All Operating and Replacement Reserves (except Negative Reserves)** – currently Replacement Reserve only;
- **S_MWR_ROI, and S_MWR_NI –** when transfers from Ireland to Northern Ireland and vice versa are at a maximum;

- **S_SNSP_TOT –** when the System Non-Synchronous Penetration (SNSP) level is equal to the SNSP limit;
- **S_RoCoF –** ensures Ireland and NI power systems do not exceed Rate of Change of Frequency (RoCoF) limits;
- **S_MWMAX_NI_GT, S_REP_NI, S_REP_ROI, and S_MWMAX_ROI_GT** – combined MW output of OCGTs must be less than set MW number in Ireland and NI. This is required for replacement reserve in NI and Ireland;
- **S_MWMAX_CRK_MW , and S_MWMAX_STH_MW –** generation restriction in the Cork area and Southern Region; and
- **other constraints that may be added from time to time**.

This option seeks to broaden the circumstances under which the System Services Flag would be set to zero. This approach would not change the imbalance pricing, but impacts on the settlement process for those units available to deliver and bound by a constraint listed above.

3.4 Assessment of the option to remove Difference Charges where Operational Constraints are binding

SEMO carried out analysis on the effect of making this change for a number of specific dates of interest (9th October 2018 and 24th January 2019). This analysis was presented at Working Group 2 (falling out of Mod_32_18), and some of the results of this are shown below.

This analysis by SEMO compares the proposal to the arrangements which were in place at that time. However, it is important to caveat the following analysis due to the TSC Modification (Mod_09_19) having been approved and effective from 2 May 2019. This modification removed four System Operator Flags, which relate to constraints with an upper MW limit on the transmission system. This modification removes these constraints from the imbalance pricing process. Further information on this is provided in section 1.2.

Figure 22: 9th October 2018 – Arrangements at that time versus SEMO proposal

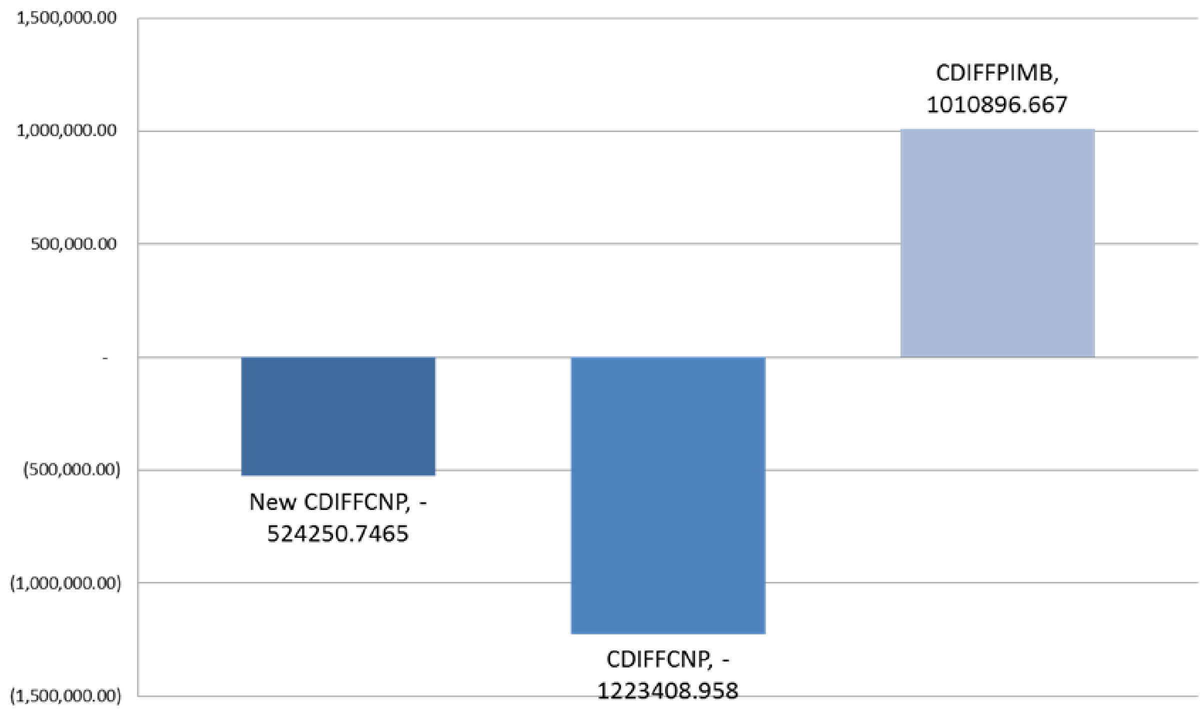


Figure 22 above shows that for on the 9th October 2018 an amount of €1.011m was due to be paid to suppliers due to the imbalance price exceeding the Strike Price during that day. Reliability Option holders across the island incurred difference charges totalling €1.223m. If this proposed option was in place the Reliability Option holders would have incurred a reduced amount of difference charges totalling €0.524m. However, based on this day alone a shortfall in the socialisation fund of €0.487m between what was due to be received and what was due to be paid out may have arisen. SEMO acknowledged the difficulty in estimating this figure at the Working Group and that the estimate of €0.524m may have been different due to a known issue in the systems at that time which has since been resolved.

Figure 23: 9th October 2018 – Arrangements at the time versus SEMO proposal (per unit basis)

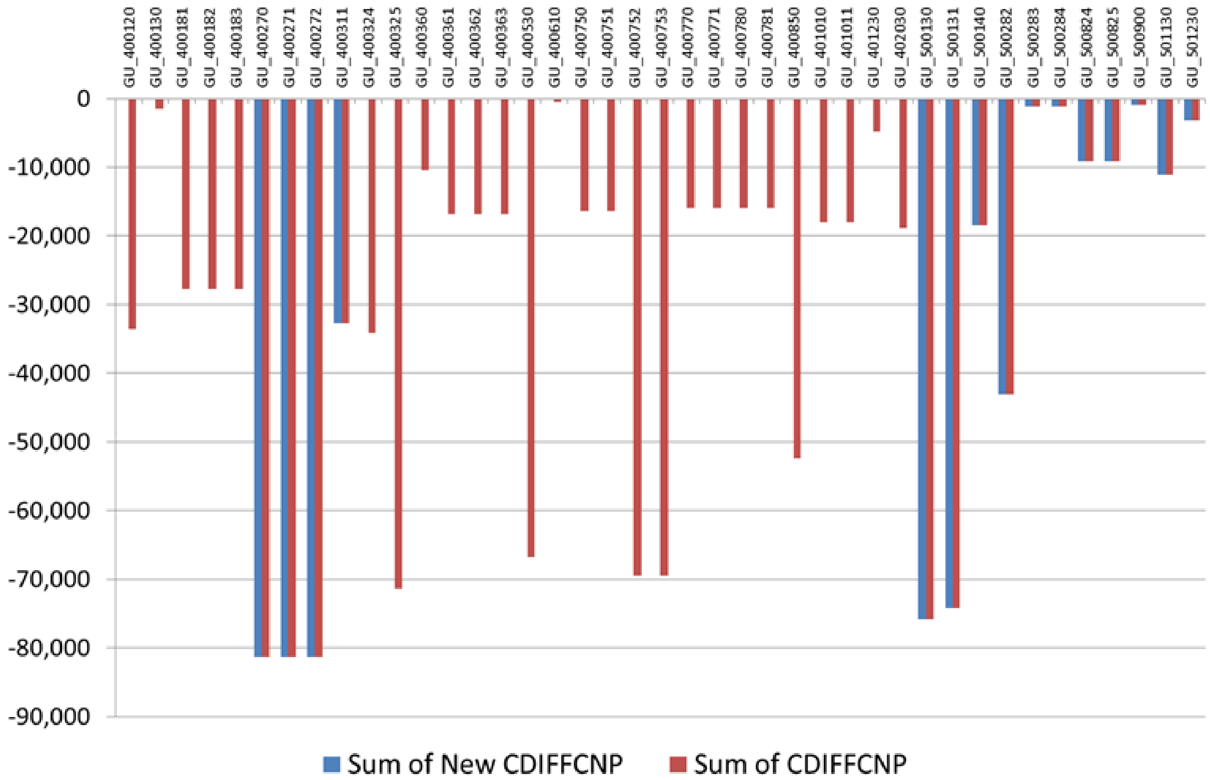


Figure 23 was presented at the Working Group and shows the capacity providers with a Reliability Option and their exposure to Reliability Option difference payments on 9 October 2018 (in red) and their estimated exposure if this option being consulted upon had been in place (in blue). This shows that some units would be protected (due to being bound by a constraint) while those who were not available to deliver and/or not bound by the constraint remained exposed to difference payments to the same extent.

Figure 24: 24th January 2019 – Arrangements at the time versus SEMO proposal

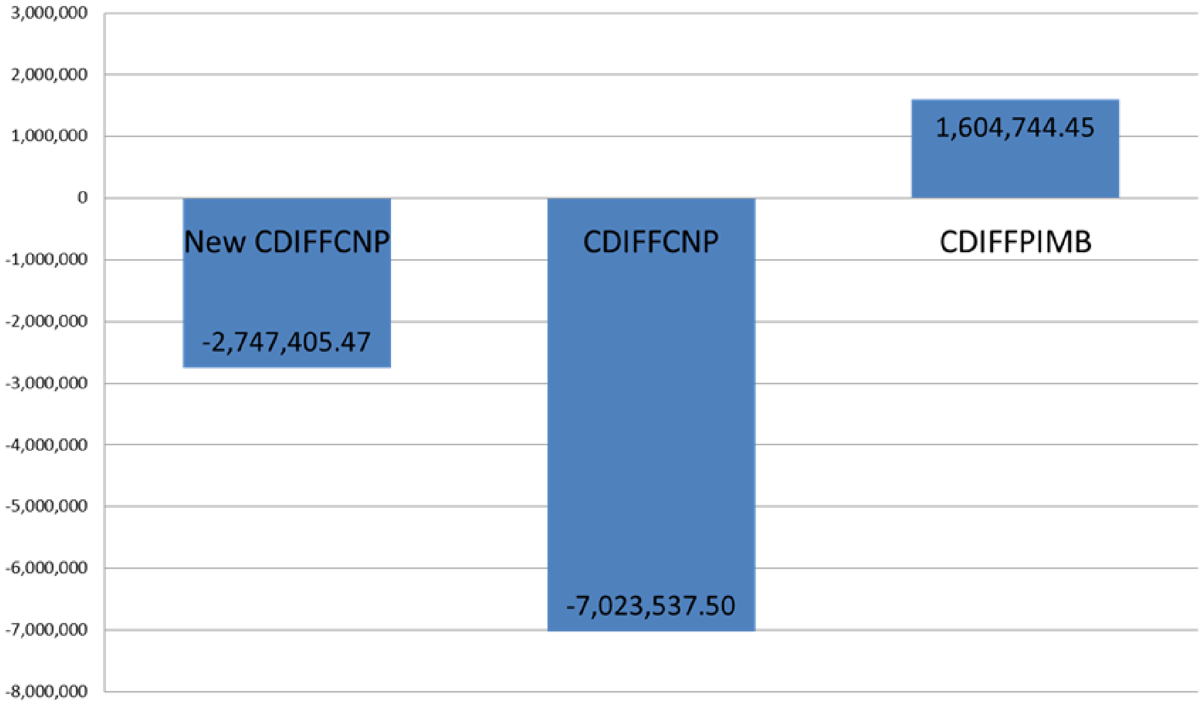


Figure 24 above shows that on the 24th January 2019 an amount of €1.605m was due to be paid to suppliers due to the imbalance price exceeding the strike price during that day. Reliability Option holders across the island incurred difference charges totalling €7.023m. If this proposed option was in place the Reliability Option holders would have incurred a reduced amount of difference charges totalling €2.747m. Based on this day alone a surplus in the socialisation fund of €5.418m between what was due to be received and what was due to be paid out is estimated.

Figure 25: 24th January 2019 – Arrangements at the time versus SEMO proposal (per unit basis)

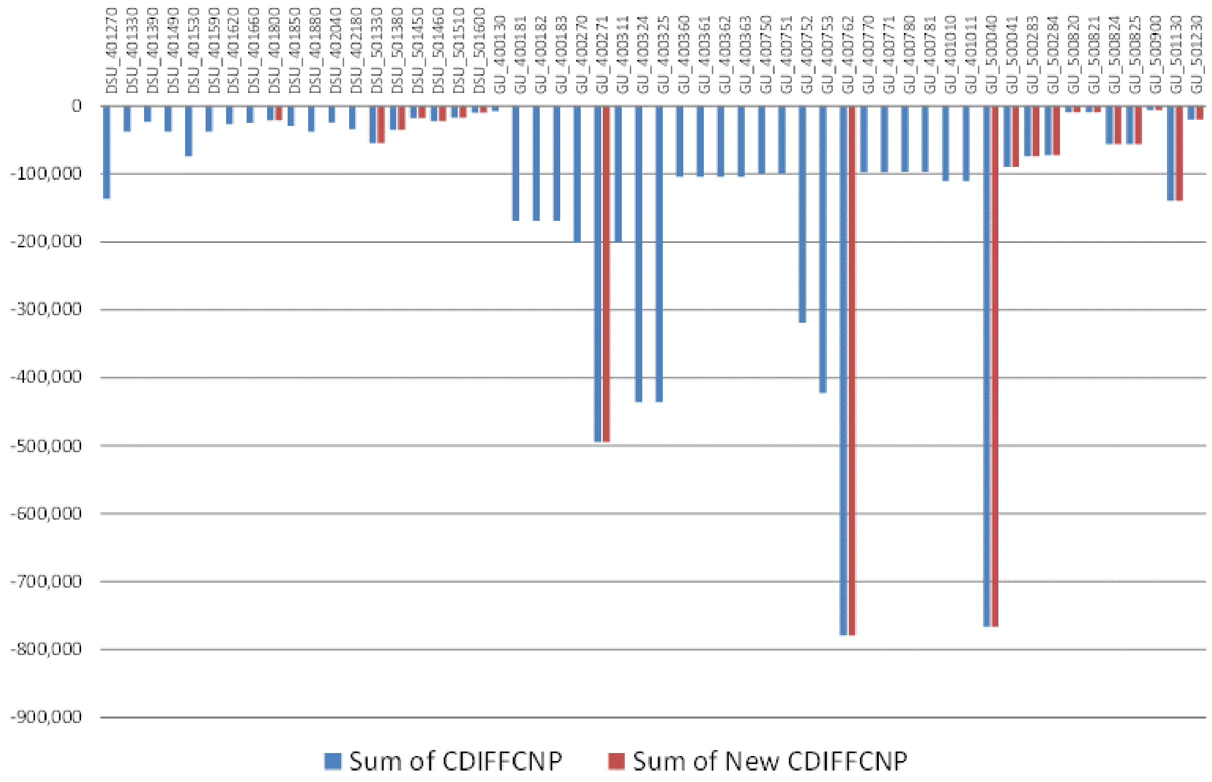


Figure 25 was presented at the Working Group and shows the capacity providers with a Reliability Option and their exposure to Reliability Option difference payments on the 24th January 2019 (in blue) and their estimated exposure if this option being consulted upon had been in place (in red). This shows that some units would be protected (due to being bound by a constraint) while those who were not available to deliver and/or not bound by the constraint remained exposed to difference payments to the same extent.

Summary of Assessment

Figure 22 shows the events of October 9th 2018 whereby under the arrangements at that time, circa €1.2m was paid in by generators and circa €1m was paid out to suppliers. With SEMO's proposed change on this date generators may have been required to pay the reduced amount of circa €0.5m due to the change to the System Service Flag reflecting Operational Constraints. This reduced exposure for generators on this specific date would not cover the amount required for the suppliers' (which remained unchanged) as part of the Reliability Option hedge. This highlights an issue that making any change to the exposure to Difference Charges may affect the balance of RO Difference Charges and Difference Payments i.e. the socialisation fund could be impacted. However SEMO acknowledged the difficulty in estimating this figure at the Working Group and that the estimate of €0.524m (estimate of Difference Charges with proposed change) may have been different due to a known issue in the systems at that time which has since been resolved.

The analysis carried out by SEMO covers two specific days of interest, it does not show the overall effect of this proposed change over a large number of days due to the fact that occurrence of these events has been rare. What this analysis does show is that SEMO's proposed change does prevent any repeat of an event like that which occurred on January 24th 2019 whereby units which could not be dispatched due to the presence of Operational Constraints were subject to Difference Charges. However with the implementation of Mod_09_19 effective from 3 May 2019, it is considered that the likelihood of such an event with extreme prices is now reduced.

The implementation of this proposal may change the short-term performance incentives for RO holders, with generators covered by certain Operational Constraints possibly facing reduced exposure for non-performance. While it is difficult to fully assess the effects of this without further market experience, the reduced exposure to difference payments by RO holders would map over to a widening of the 'hole in the hedge' – that part of the demand base not covered by difference payments – and a potential associated impact on the Capacity Market Socialisation Fund. This Fund is by design a backstop only and not intended to be called upon regularly.

In weighing the broader upsides and downsides of the option to remove exposure to the Difference Charges for generators behind an export constraint, a key upside would be that units that cannot be dispatched for network reasons, but are otherwise fully available to the limit of their control, would not be penalised when the Balancing Price exceeds the Strike Price. This would remove the commercial risk that is posed by that scenario for low-utilisation plant in particular, which regularly enter the BM with no ex-ante position for their RO to settle against. On the downside, this option could present a risk of introducing a hidden locational element to the Capacity Market by distorting the CRM auction in that the reduced risk of exposure to RO Difference Charges would, all else being equal, incrementally incentivise new plant to locate behind an export constraint instead of inside the constrained area. Further, existing units could observe a change in the competitive dynamic within the CRM, whereby units behind an export constraint would enjoy the disapplication of difference charges during these albeit rare periods, while those inside the constrained areas would not.

As set out already in section Initial steps taken 1.2, the SEM Committee decided to implement some changes quickly in order to reduce the possibility of further extreme pricing events while further approaches are investigated and developed (including this consultation). With these changes in place the likelihood of a pricing event like that which occurred on 24th January 2019 and the related RO Difference Charges are reduced.

Conclusion

This option, which originates from a proposal suggested by SEMO at the TSC Working Groups, seeks to broaden the circumstances under which the System Services Flag would be set to zero. This approach would not change the imbalance pricing, but impacts on the settlement process for those units available to deliver and bound by a constraint listed above. Meanwhile units that are not available to deliver and/or not bound by the following constraints would not be flagged with a System Service Flag and thus would still be exposed to Difference Charges if the imbalance price went above the strike price:

- **All Operating and Replacement Reserves (except Negative Reserves)** – currently Replacement Reserve only;
- **S_MWR_ROI, and S_MWR_NI –** when transfers from Ireland to Northern Ireland and vice versa are at a maximum;
- **S_SNSP_TOT –** when the System Non-Synchronous Penetration (SNSP) level is equal to the SNSP limit;
- **S_RoCoF –** ensures Ireland and NI power systems do not exceed Rate of Change of Frequency (RoCoF) limits;
- **S_MWMAX_NI_GT, S_REP_NI, S_REP_ROI, and S_MWMAX_ROI_GT** – combined MW output of OCGTs must be less than set MW number in Ireland and NI. This is required for replacement reserve in NI and Ireland;
- **S_MWMAX_CRK_MW , and S_MWMAX_STH_MW –** generation restriction in the Cork area and Southern Region; and
- **other constraints that may be added from time to time**.

The SEMO analysis is specific to two particular days. The SEM Committee would welcome respondents' views on this proposed option in the context of the wider market implications to help inform the outcome of this consultation. It is also worth bearing in mind when responding the initial step already taken in respect of the imbalance pricing process (outlined in section 1.2).

In terms of implementation, should this option be supported in the SEM Committee decision to this consultation, a TSC modification (to Appendix N: Flagging and Tagging) would need to be progressed through the Modification process together with a revision to the TSOs Methodology for Determining System Operator and Non-Marginal Flags. Upon approval of a modification the decision could be implemented relatively quickly through configuration settings in the Central Market Systems, avoiding the longer timelines needed for system changes.

3.5 Consultation Questions regarding the removal of Difference Charges where Operational Constraints are binding

The SEM Committee is seeking views on this proposed change to the Capacity Market which would remove Difference Charges for those units which are available to deliver but cannot be dispatched up to meet their reliability option obligation due to a binding Operational Constraint.

Respondents are asked to consider the following questions and to provide answers in their responses to this consultation.

3.1) Do you support this Capacity Market option and its implementation in the SEM?

3.2) Do you have any concerns regarding the removal of Difference Charges where Operational Constraints are binding, including the risk of unintended consequences? If so, please explain these concerns.

3.3) Do you consider this proposed change is in keeping with the broader CRM detailed design? Please explain your view.

3.4) Do you have any views on this option from a consumer perspective?

3.5) Do you have a strong view regarding an alternative option which could be implemented, i.e. preferably requiring only a configuration change rather than a system change?

4. NEXT STEPS

Interested parties are invited to respond to this consultation, providing answers to the questions set out in this paper.

Responses to this consultation paper should be sent to Thomas Quinn (tquinn@cru.ie) and Karen Shiels (Karen.Shiels@uregni.gov.uk) by 17.00 on Friday 12th July 2019.

The RAs will endeavour to progress a decision as soon as possible on these proposals recognising that any decision will also require a TSC modification to be progressed through the modification process and may also require changes to the TSOs' "Methodology for Determining System Operator and Non-Marginal Flags" paper. Upon these decisions SEMO can then progress the necessary system configuration changes to implement any decision coming out of this consultation.

Please note that SEM Committee intends to publish all responses unless marked confidential. While respondents may wish to identify some aspects of their responses as confidential, we request that non-confidential versions are also provided, or that the confidential information is provided in a separate annex. Please note that both Regulatory Authorities are subject to Freedom of Information legislation.

APPENDIX: DETAILED ANALYSIS OF SIMPLE NIV TAGGING

This Appendix presents analysis of both the actual imbalance prices (called "original imbalance prices" hereafter) which occurred in the five months subsequent to I-SEM Go-Live on 1st October 2018, and the theoretical imbalance prices which would have pertained if Simple NIV tagging had been in place.

The TSOs have modelled the prices that would have pertained if Simple NIV tagging had been in place and provided this data, both 5-minute prices and 30-minute prices, to the RAs.

There is data missing for some 5-minute and 30-minute periods, as detailed in the table below, but it shouldn't be significant enough to affect the analysis. Note that where the prices from Simple NIV tagging (called "Simple NIV prices" hereafter) are missing, the original imbalance prices are removed for the relevant time periods also for purposes of comparing like-with-like. Other variables such as the Day Ahead Market price, etc. are also removed for the relevant time periods in order to compare like-with-like.

5-minute data

Missing	1,551
Total	43,489
% Missing	3.6%

30-minute data

Missing	435
Total	7,248
% Missing	6.0%

More analysis was carried out on the 30-minute data as these are the prices which market participants are settled against and which market participants are thus most interested in. Other relevant data points such as Day Ahead Market prices can also be more easily compared with the 30-minute prices.

5-minute data: Descriptive Statistics, Scatter Plots and Price Duration Curves

Descriptive Statistics

Table **5** below outlines descriptive statistics for the 5-minute NIV (in MW), the 5-minute original imbalance price and the 5-minute Simple NIV price.

Table 5

	NIV5 (MW)	Original Imbalance Price (€/MWh)	Simple NIV Price (€/MWh)
Average	61.60	65.50	71.83
Median	70.52	52.22	54.33
Maximum	1366.82	5636.62	687.41
Minimum	-1471.13	-1000	-172.32
Standard Deviation	359.98	114.38	63.86
Coefficient of Variation	5.84	1.75	0.89
Kurtosis	0.491	958.93	14.662
Correlation with NIV		0.384	0.694

The 5-minute Simple NIV prices have a significantly lower standard deviation and coefficient of variation.

While the 5-minute Simple NIV prices have a higher average they have a significantly lower maximum price and a significantly less negative minimum price.

The 5-minute Simple NIV prices are significantly more correlated with the NIV.

The very high kurtosis value for the 5-minute original imbalance prices relative to the Simple NIV prices show that there are far more very high and very low prices in the original imbalance price data.

Scatter Plots

The following graphs show scatter plots of the 5-minute prices against the NIV, with prices on the vertical axis and the NIV on the horizontal axis. Figure 27 is a “zoomed in” version of Figure 26. The 5-minute original imbalance prices are the blue dots and the 5-minute Simple NIV prices are the orange dots.

The outlier extremely high prices are clear in the 5-minute original prices. Some of these occur when the NIV is negative (i.e. the market is long) which is not a good outcome. The greater number of negative prices is also clear in the 5-minute original prices. Some of the most extreme negative prices occur when the market is not that long, or indeed is short (i.e. the NIV is positive), which is again not a good outcome.

Figure 26

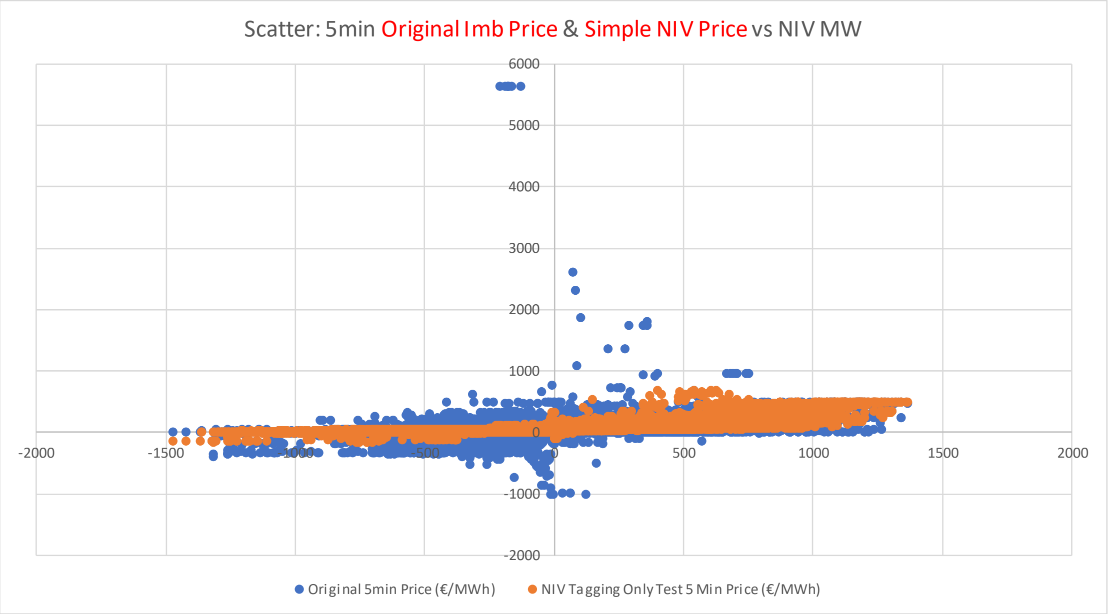
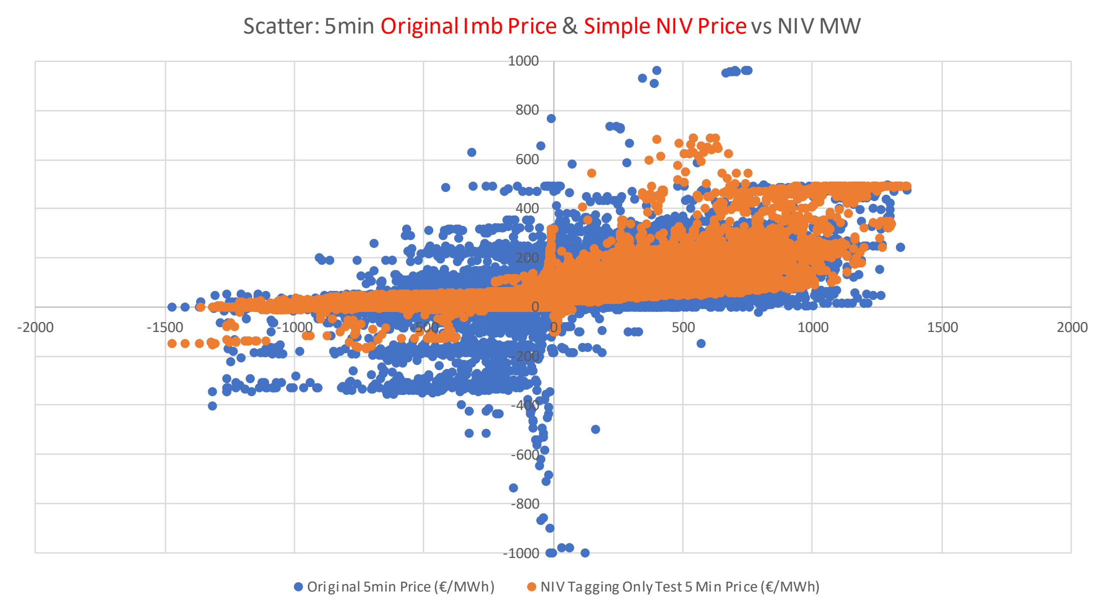


Figure 27



Price Duration Curves

The following graphs present the data as price duration curves. The blue line is the 5-minute original imbalance price and the orange line is the 5-minute Simple NIV price. The graphs "zoom in" to different points on the duration curves. It can be seen that the major differences in the price duration curves occur at the very high prices and the very low prices.

Figure 28

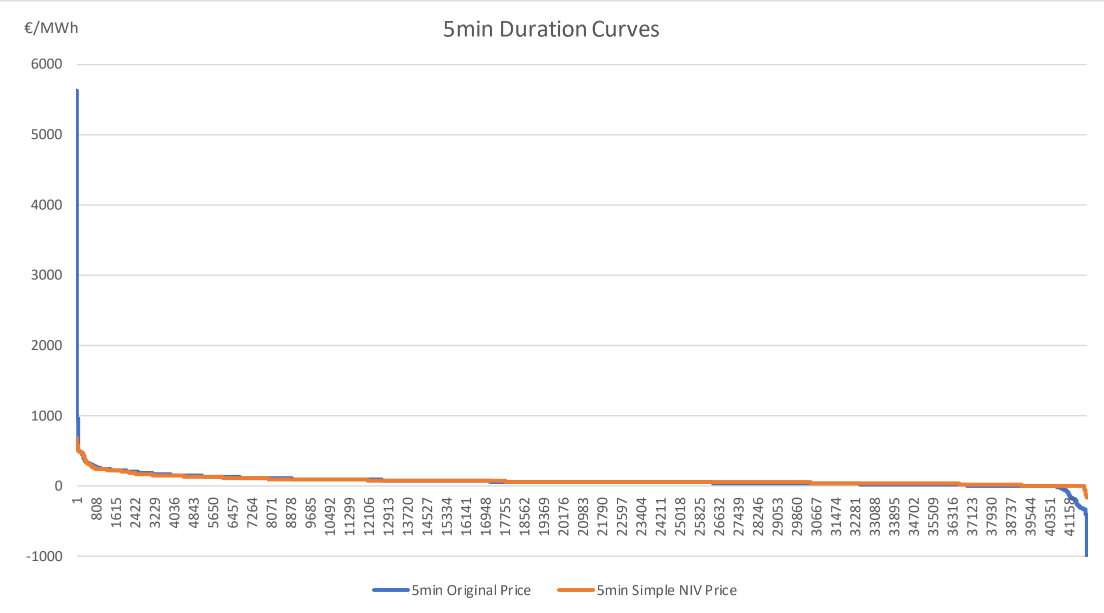


Figure 29

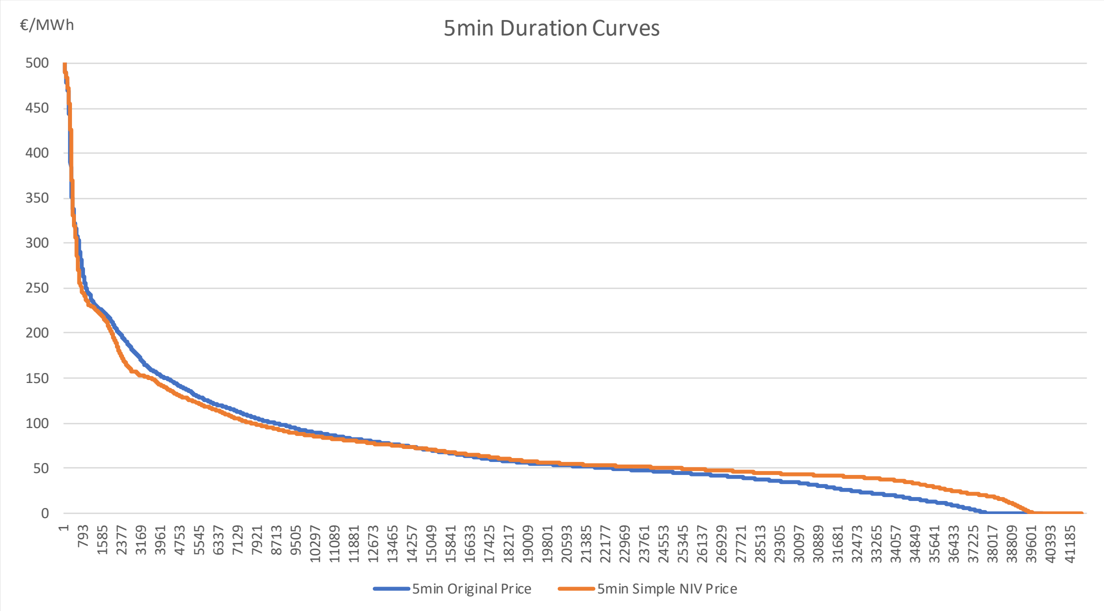


Figure 30

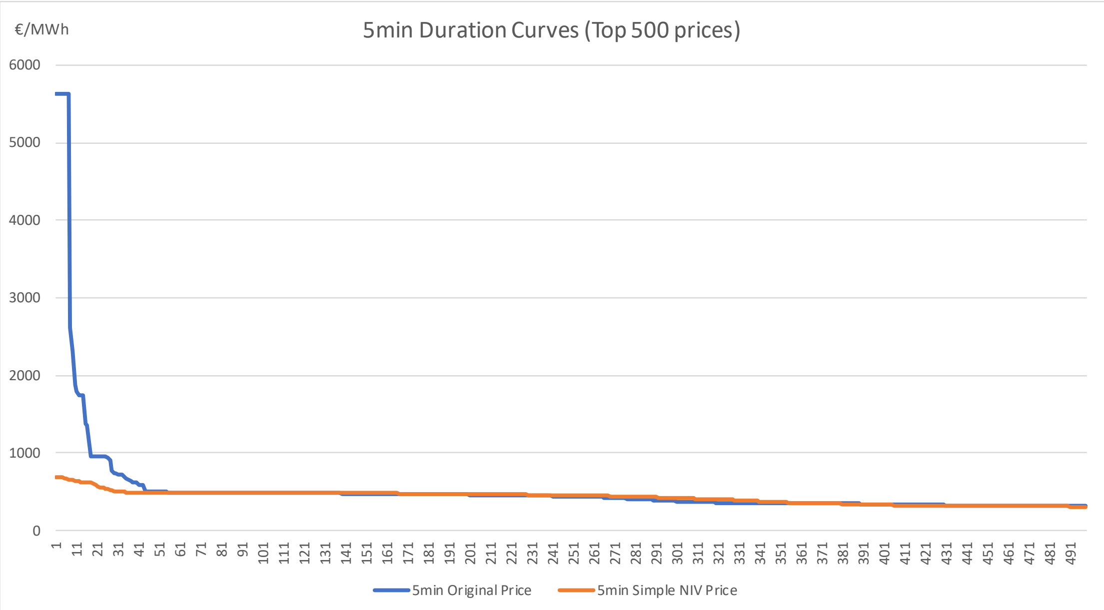
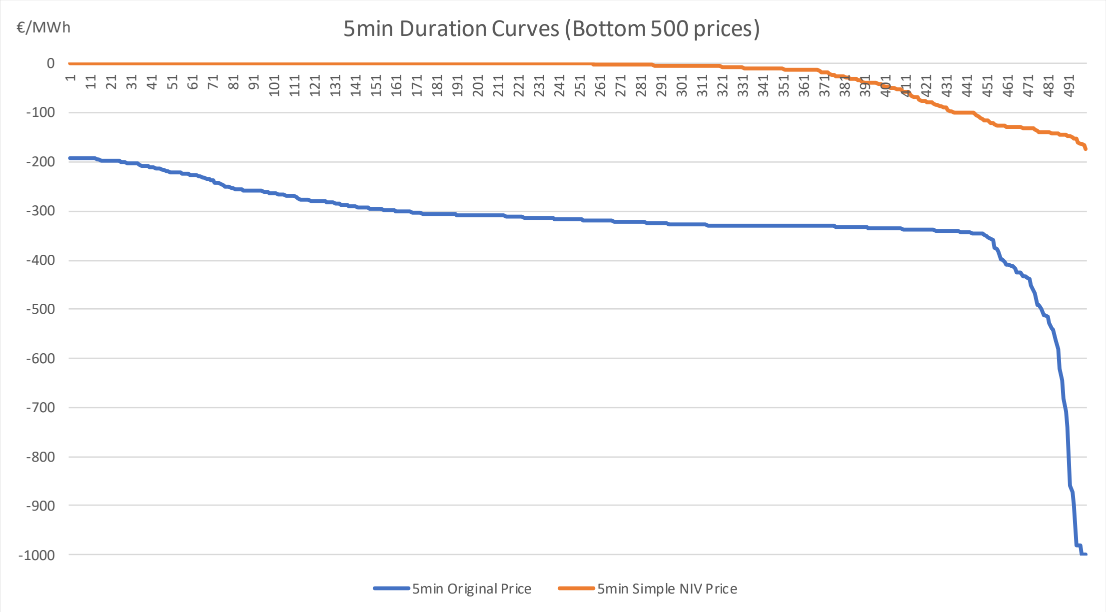


Figure 31


5min Duration Curves (Bottom 500 prices)
€/MWh
0
-100
-200
-300
-400
-500
-600
-700
-800
-900
-1000
5min Original Price
5min Simple NIV Price

30-minute data: Descriptive Statistics, Scatter Plots, and Price Duration Curves

Descriptive Statistics

Table 6 below outlines descriptive statistics for the NIV (in MW), the original imbalance price, the Simple NIV price, the Day Ahead Market (DAM) price, the Market Back Up price (which is a weighted average of the DAM price and IDM prices), the System Demand and Wind Generation.

Table 6

	NIV30 (MW)	Original Imbalance Price (€/MWh)	Simple NIV Price (€/MWh)	DAM Price (€/MWh)	BackUp Price (€/MWh)	System Demand (MW)	Wind Generation (MW)
Average	63.59	66.06	72.06	70.40	70.398	4464.31	1669.65
Median	71.64	56.19	55.52	66.45	66.40	4623.43	1630.84
Max	1316	3773.69	635.57	365.04	365.24	6485.12	3927.88
Min	-1305	-281.16	-144.49	-10.29	-10.64	2678.34	23.55
Standard Deviation	355.12	89.70	61.37	31.46	31.43	866.02	984.98
Coefficient of Variation	5.58	1.36	0.85	0.447	0.446	0.19	0.59
Kurtosis	0.541	471.577	15.302	13.389	13.253	-1.111	-1.141

The Simple NIV prices have a significantly lower standard deviation and coefficient of variation than the original imbalance prices. However, they have a significantly higher standard deviation and coefficient of variation than the DAM price, which is important as the imbalance price should still allow for some price volatility. The kurtosis of the Simple NIV prices are significantly lower than that of the original prices, while still being higher than that of the DAM prices.

The Simple NIV prices have a lower maximum price, and a less negative minimum price, than the original imbalance prices, and a higher average price than the original imbalance prices (due to less negative prices). Indeed the average Simple NIV price is higher than the average DAM price, while the average original imbalance price is lower than the DAM price. This is more in line with expectations as the average NIV over the period was positive at 62.59 MW.

Temporal Volatility

Table 7 below outlines descriptive statistics, when looking at the change from one half hour to the next for each variable (one hour to the next for the DAM Price, which is hourly).

Table 7

Change	NIV30 (MW)	Original Imbalance Price (€/MWh)	Simple NIV Price (€/MWh)	DAM Price (€/MWh)	BackUp Price (€/MWh)	System Demand (MW)	Wind Generation (MW)
Average (abs)	79.47	28.37	13.57	4.53	4.56	114.15	65.84
Max	598.62	2793.13	448.86	140.83	140.60	573.86	448.30
Min	-612.6	-1864.24	-459.96	-139.60	-139.09	-373.30	-448.89
Standard Deviation (abs)	77.35	64.56	23.40	11.20	11.06	98.85	60.78
Coefficient of Variation	0.97	2.28	1.72	2.47	2.43	0.87	0.92

Table 8 below gives the average change from one half hour to the next (one hour to the next for the DAM Price) as a % of the average value, for each variable. It shows that the original imbalance price changes on average by 43% of its average value from one half-hour to the next, which is very significant temporal volatility. The DAM price changes on average by 6% of its average value from one hour to the next, while the Simple NIV price changes on average by 19% of its average value from one half-hour to the next. This figure of 19% is further evidence that the Simple NIV price retains significant volatility, while not being as volatile as the original imbalance price.

Table 8

	NIV30 (MW)	Original Imbalance Price (€/MWh)	Simple NIV Price (€/MWh)	DAM Price (€/MWh)	BackUp Price (€/MWh)	System Demand (MW)	Wind Generation (MW)
	125%	43%	19%	6%	6%	3%	4%

Correlations

Table 9 below shows the correlation of each variable with every other variable.

The most important correlations for this analysis are highlighted in red but there are other interesting correlations also.

Table 9

	NIV30	Original Imbalance Price	Simple NIV Price	DAM Price	BackUp Price	System Demand	Wind Generation
NIV30	1	0.484	0.714	0.320	0.315	0.182	-0.407
Original Price		1	0.519	0.282	0.285	0.235	-0.230
Simple NIV Price			1	0.326	0.313	0.208	-0.354
DAM Price				1	0.99	0.527	-0.424
BackUp Price					1	0.518	-0.425
System Demand						1	0.092
Wind Generation							1

Scatter Plots

Figure 32 below shows a scatter plot of the 30-minute prices against the NIV, with prices on the vertical axis and the NIV (in MW) on the horizontal axis. Figure 33 is a "zoomed in" version of the same scatter plot. The original imbalance prices are the blue dots and the Simple NIV prices are the orange dots.

The outlier extremely high prices are clear in the original imbalance prices. Some of these occur when the NIV is negative (i.e. the market is long) which is not an expected outcome. The greater number of negative prices is also clear in the original imbalance prices. Some of the most negative price occur when the market is not that long, or indeed is short (i.e. the NIV is positive), which is again not an expected outcome.

Figure 32

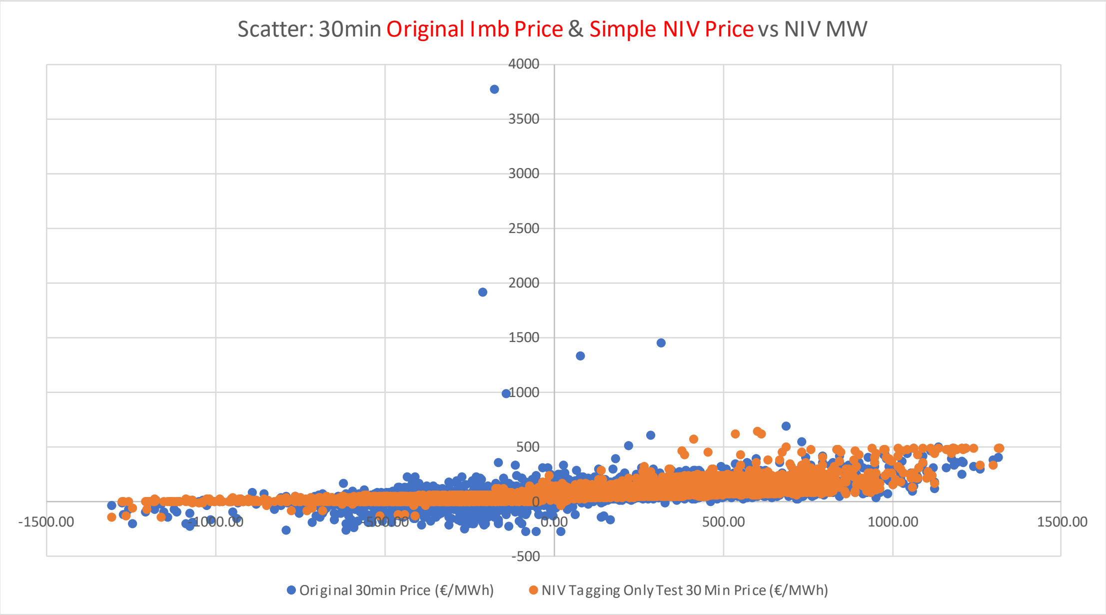


Figure 33

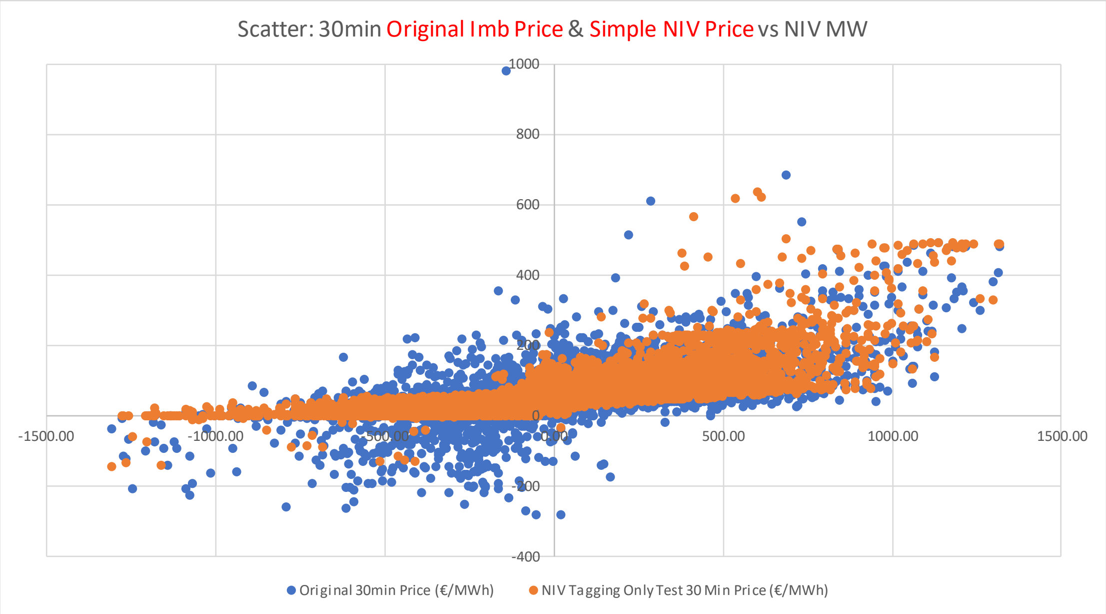


Figure 34 below shows a scatter plot of the 30-minute prices against the System Demand, with prices on the vertical axis and the System Demand on the horizontal axis. Figure 35 is a “zoomed in” version of the same scatter plot. The original imbalance prices are the blue dots and the Simple NIV prices are the orange dots.

Figure 34

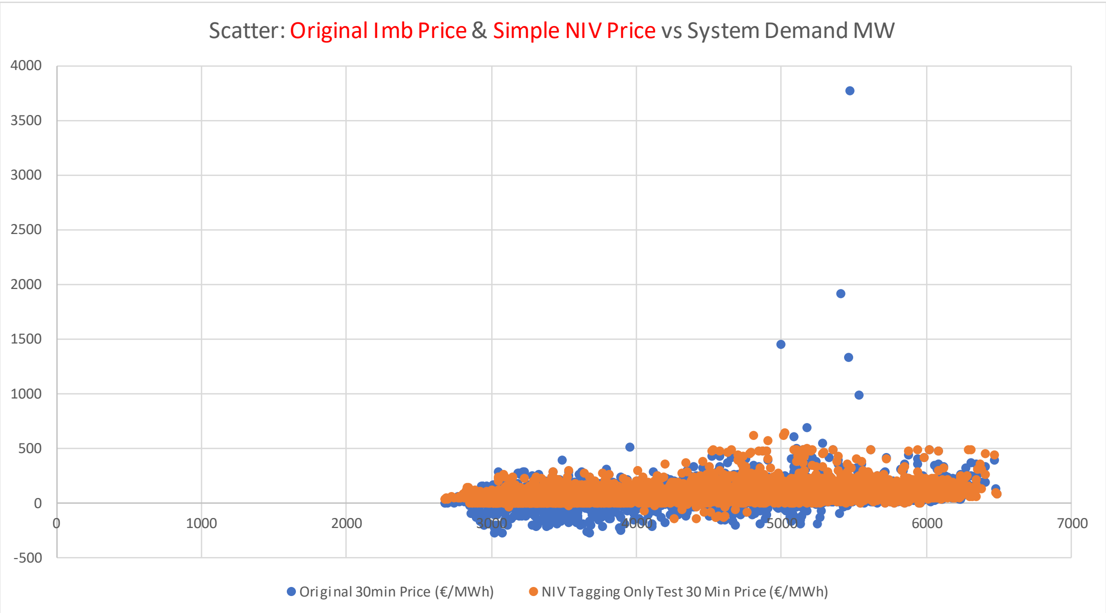


Figure 35

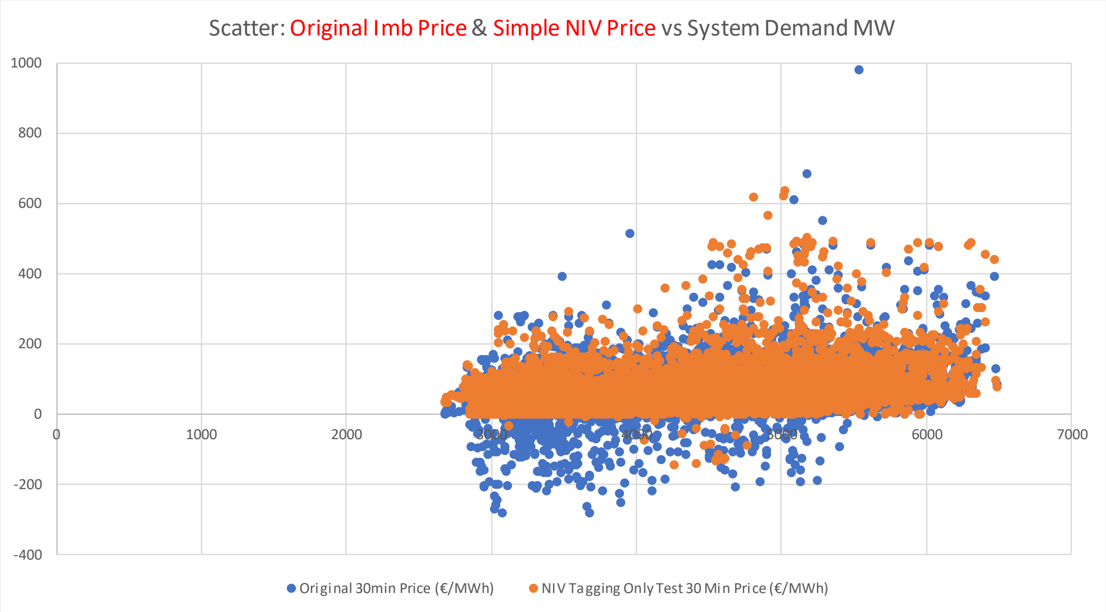


Figure 36 shows a scatter plot of the 30-minute prices against the wind generation, with prices on the vertical axis and the wind generation on the horizontal axis. Figure 37 is a "zoomed in" version of the same scatter plot. The original imbalance prices are the blue dots and the Simple NIV prices are the orange dots.

The high Simple NIV prices are more likely to occur at low levels of wind generation, which is as would be expected. A significant number of the negative original imbalance prices occur at relatively low levels of wind, which is not as would be as expected.

Figure 36

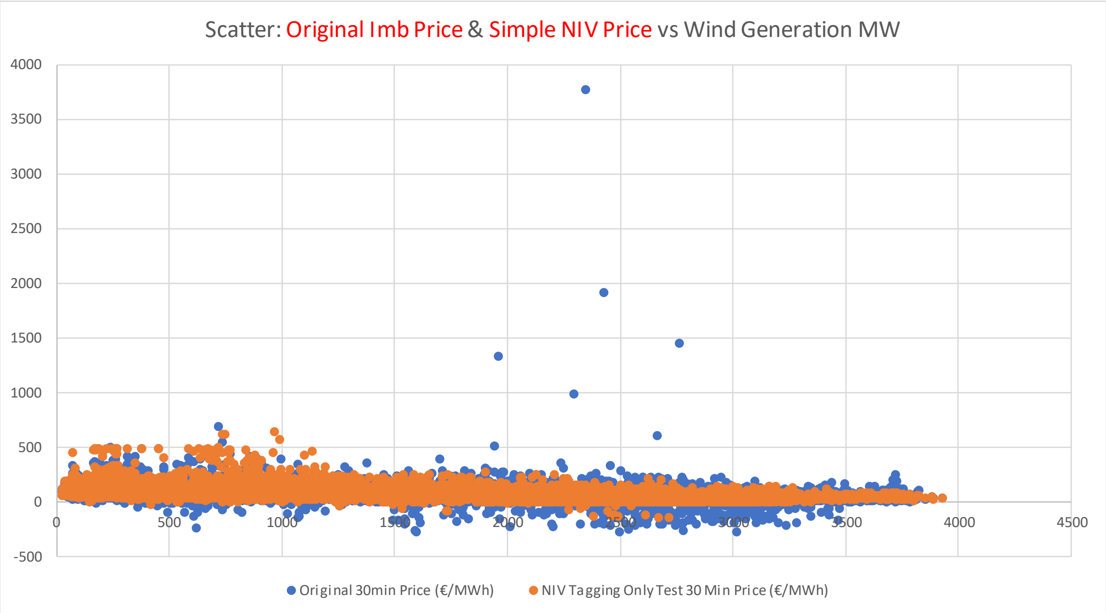


Figure 37

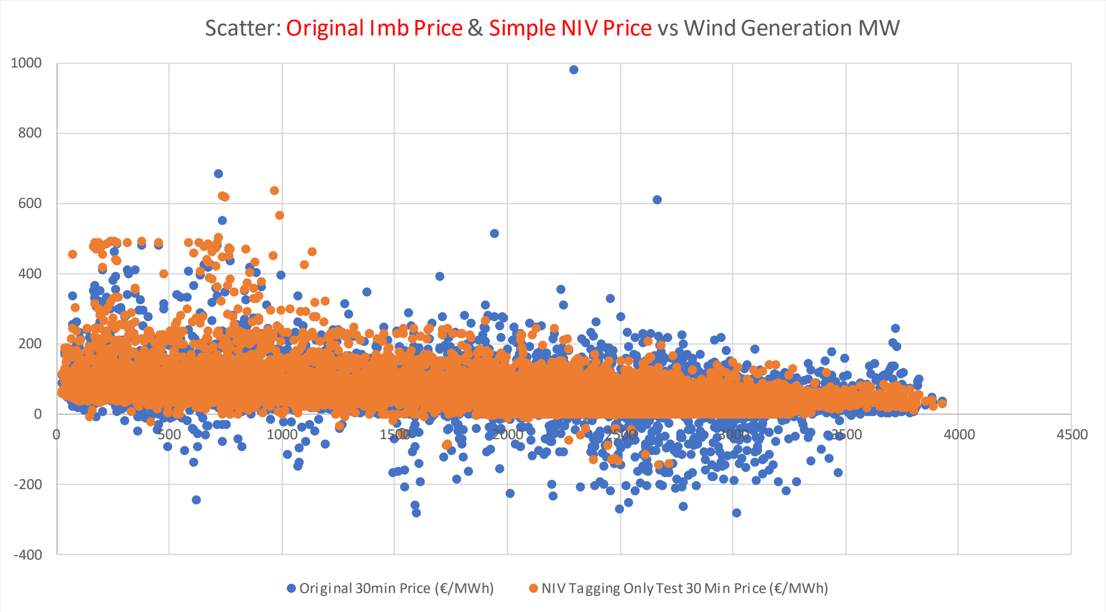


Figure 38 below shows a scatter plot of the difference between the 30-minute prices and the DAM price, against the NIV, with price differences on the vertical axis and the NIV (in MW) on the horizontal axis. Figure 39 is a “zoomed in” version of this scatter plot. The original imbalance prices minus the DAM price are the blue dots and the Simple NIV prices minus the DAM price are the orange dots.

When the NIV is positive the imbalance price would generally be expected to be higher than the DAM price, and when the NIV is negative the imbalance price would generally be expected to be lower than the DAM price. Therefore we would expect most of the dots in these graphs to be in the upper-right and lower-left quadrants.

The most concerning thing in these scatter plots is the number of blue dots in the upper-left quadrant (some of which are very high). Each of these blue dots represents a half-hour where the original imbalance price was higher than the DAM price when the NIV was negative (i.e. the market was long).

Figure 38

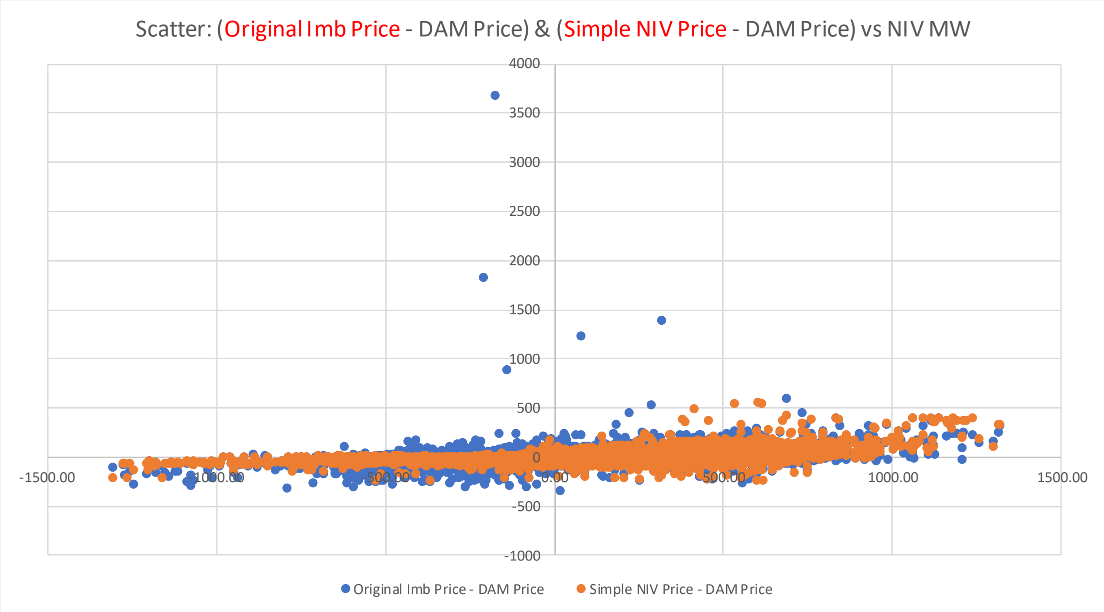
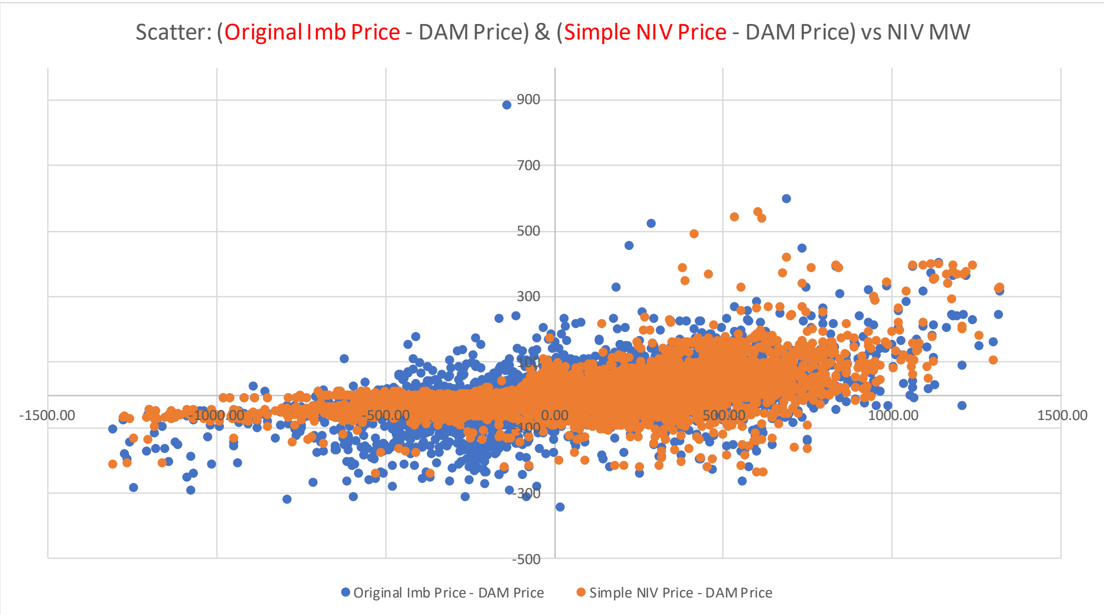


Figure 39



Price Duration Curves

The following graphs present the data as price duration curves. The blue line is the 30-minute original imbalance price and the orange line is the 30-minute Simple NIV price. The graphs “zoom in” to different points on the duration curves. It can be seen that the major differences in the price duration curves occur at the high prices and the low prices.

Figure 40

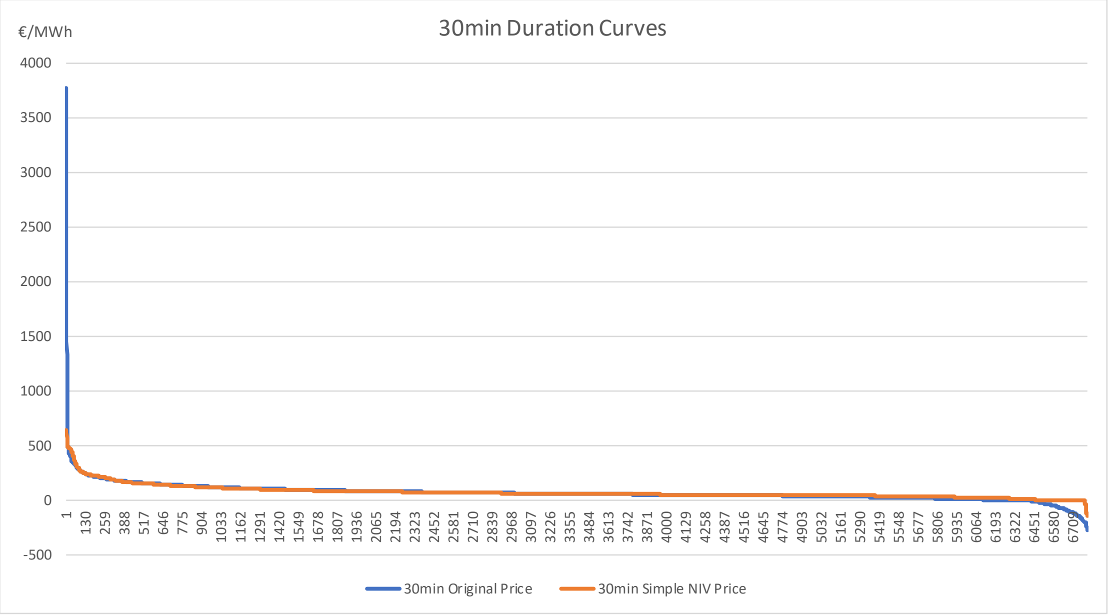


Figure 41

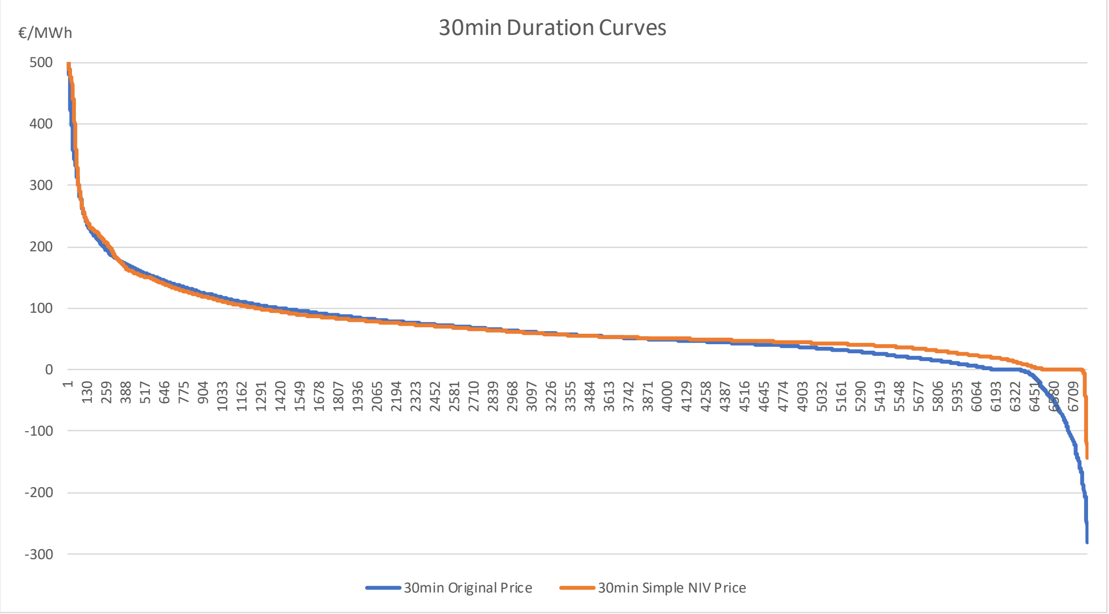


Figure 42

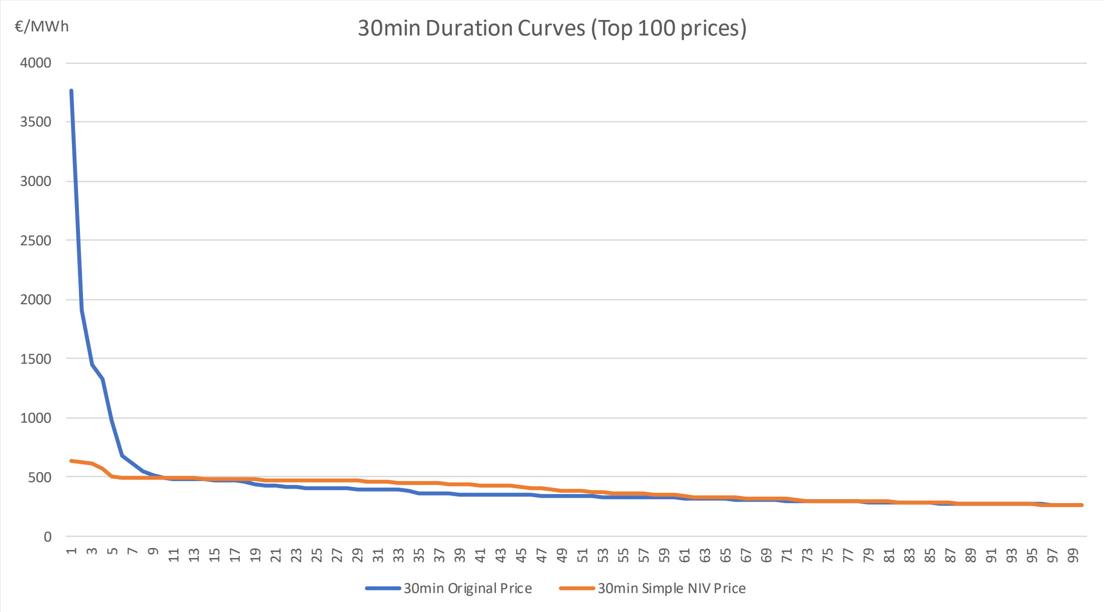
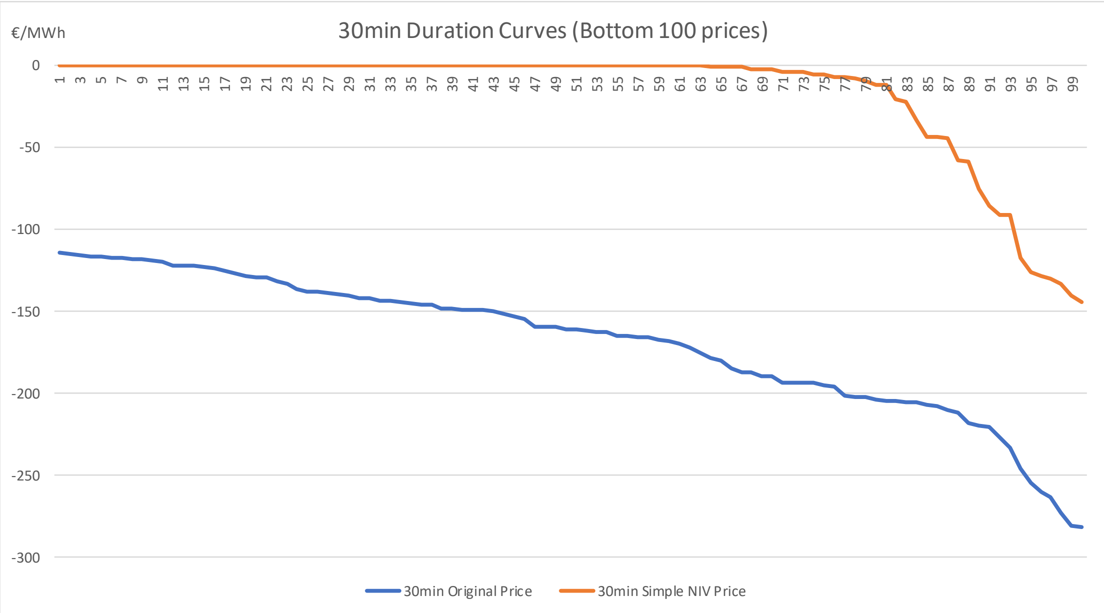


Figure 43



30-minute data: Regression Analysis

Regression analysis was carried out on the 30-minute original imbalance prices and the 30-minute Simple NIV prices to determine how much of the variation in both sets of prices was explained by the following independent variables:

- NIV;
- System Demand; and
- Wind Generation.

The results are outlined in detail in the following pages but in summary:

- The NIV, the system demand and wind generation all explain some of the variation in the original imbalance price;
- Of the three independent variables, the NIV is the most important in explaining variation in the original imbalance price;
- The NIV, the system demand and wind generation all explain some of the variation in the Simple NIV price;
- Of the three independent variables, the NIV is the most important in explaining variation in the Simple NIV price; and
- The adjusted R Square values of 0.261 and 0.523 for the regressions against the original imbalance price and the Simple NIV price respectively, when all three independent variables are included, indicate that twice as much variation in the Simple NIV price, compared to the original imbalance price, is explained by these three independent variables.

The detailed regression analysis results follow. Note that all the graphs of prices against predicted prices (i.e. predicted by the linear regression model) are provided twice; once with the y-axis at such a scale to show all the samples, and once with the y-axis zoomed in to give a better view of the majority of the samples.

Original Imbalance Prices vs NIV (MW) & System Demand & Wind Generation

Table 10

Adjusted R Square	0.261
P-value: NIV (MW)	0.00
P-value: System Demand	0.00
P-value: Wind Generation	0.00

Figure 44

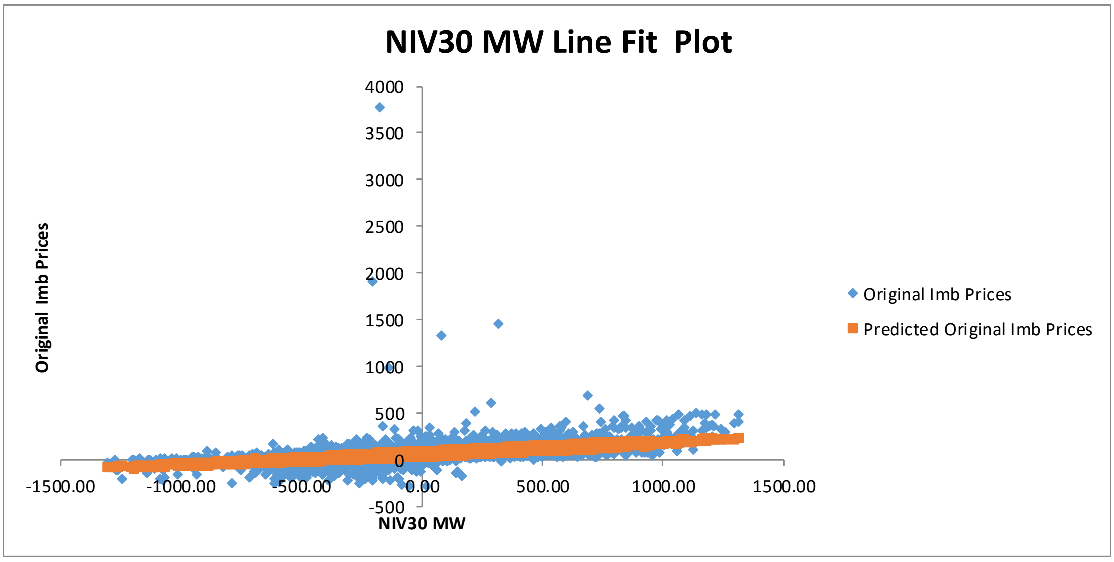


Figure 45

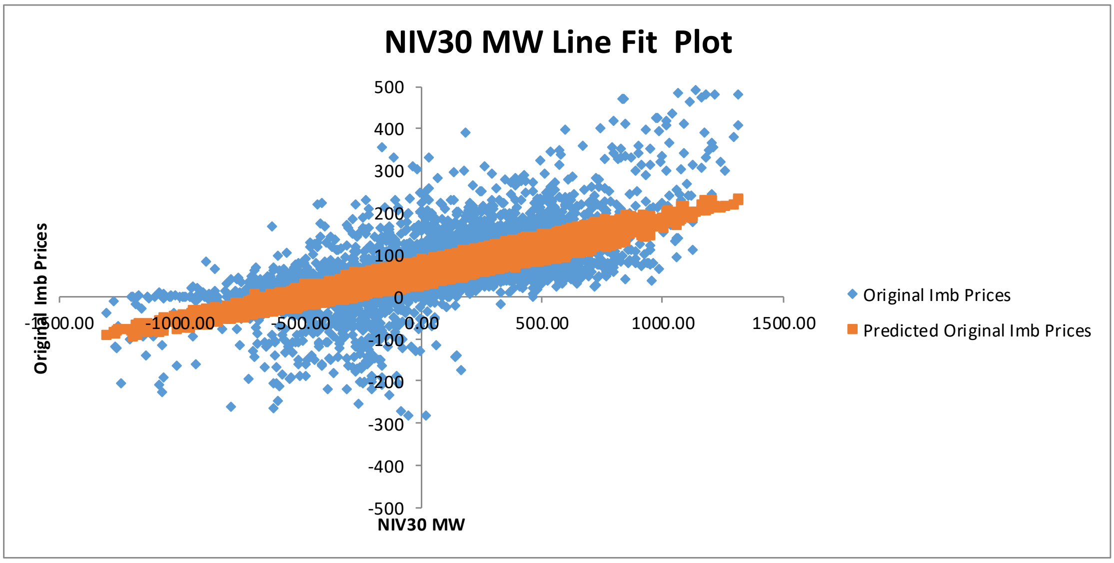


Figure 46

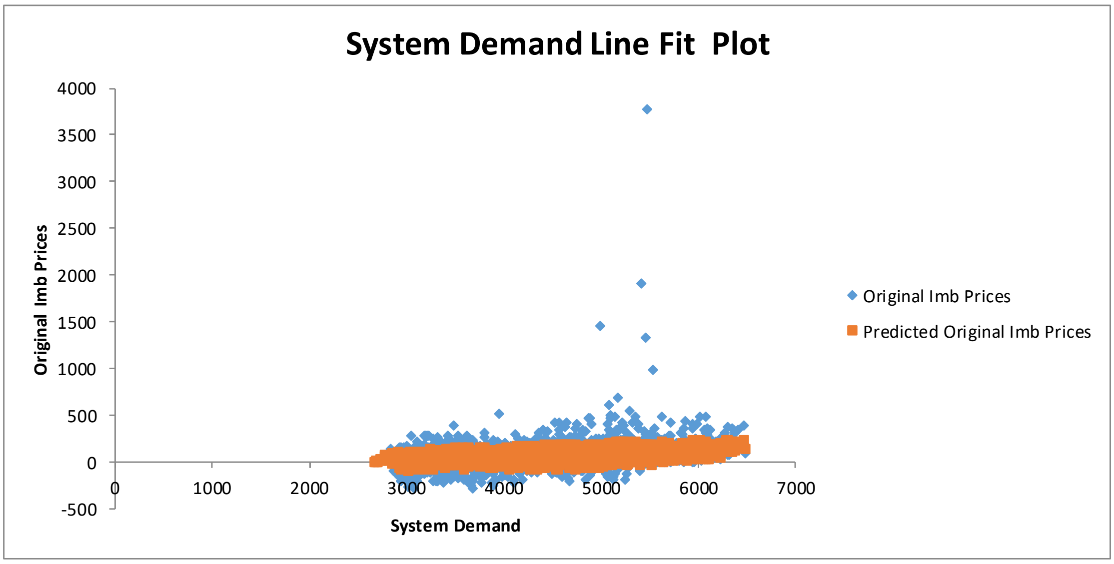


Figure 47

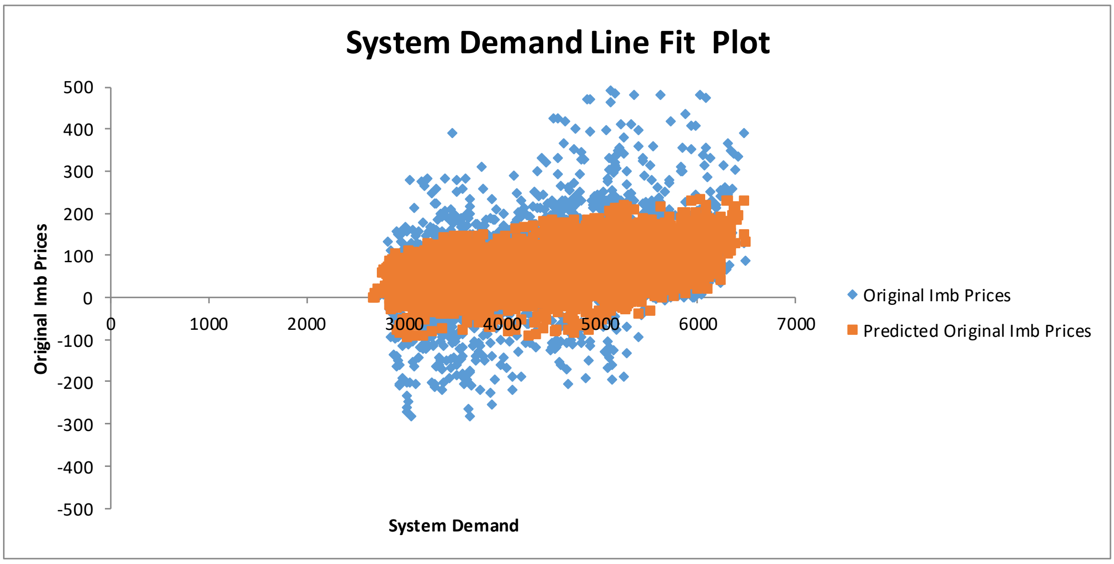


Figure 48

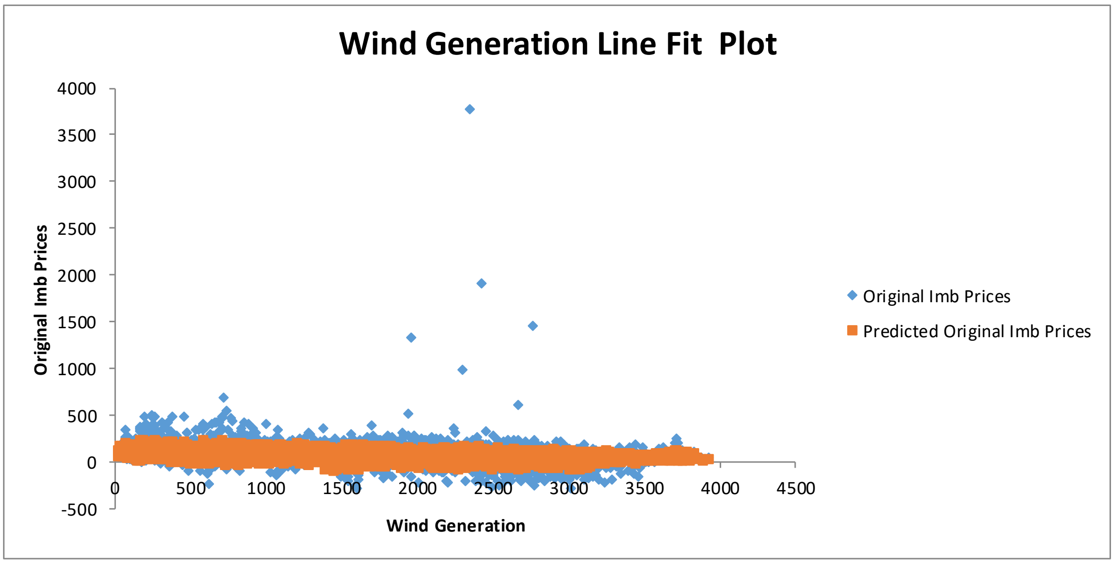
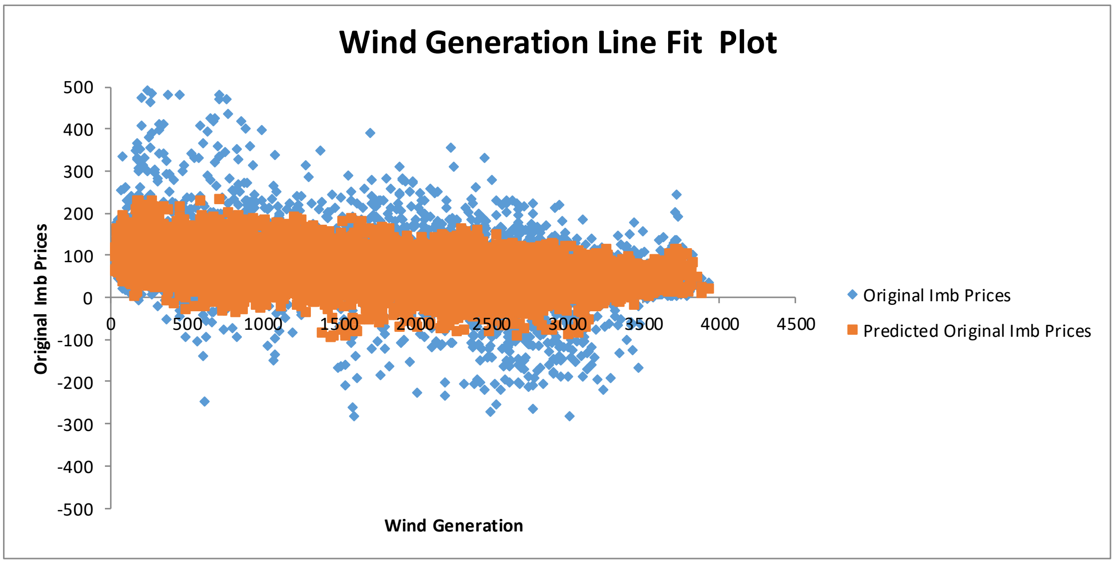


Figure 49



Original Imbalance Prices vs NIV (MW) & System Demand

Table 11

Adjusted R Square	0.256
P-value: NIV (MW)	0.00
P-value: System Demand	0.00

Original Imbalance Prices vs NIV (MW)

Table 12

Adjusted R Square	0.234
P-value: NIV (MW)	0.00

Original Imbalance Prices vs System Demand (MW)

Table 13

Adjusted R Square	0.055
P-value: System Demand	0.00

Original Imbalance Prices vs Wind Generation (MW)

Table 14

Adjusted R Square	0.053
P-value: Wind Generation	0.00

Simple NIV Prices vs NIV (MW) & System Demand & Wind Generation

Table 15

Adjusted R Square	0.523
P-value: NIV (MW)	0.00
P-value: System Demand	0.00
P-value: Wind Generation	0.00

Figure 50

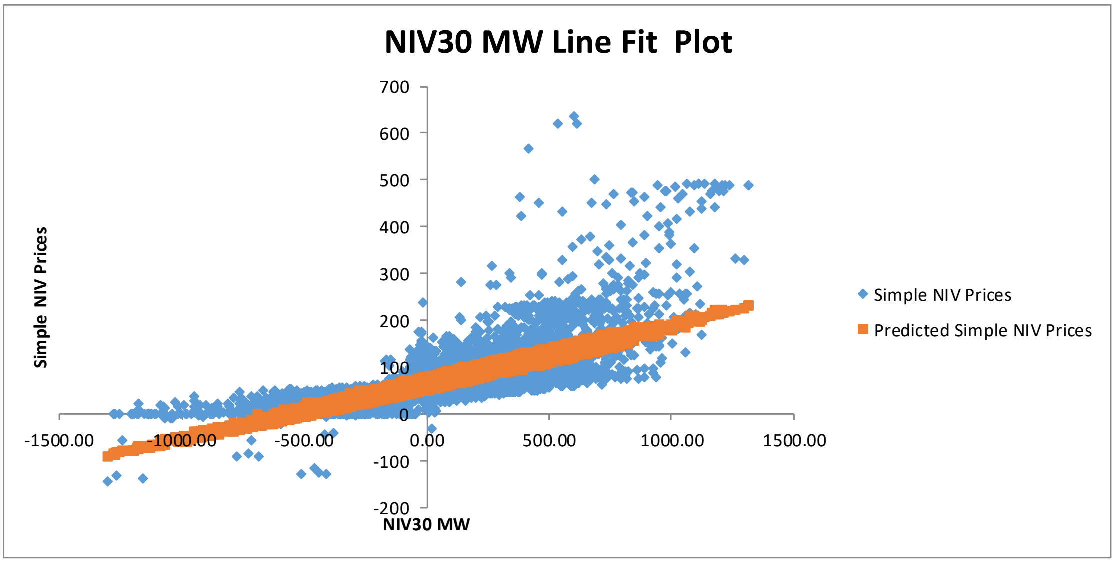


Figure 51

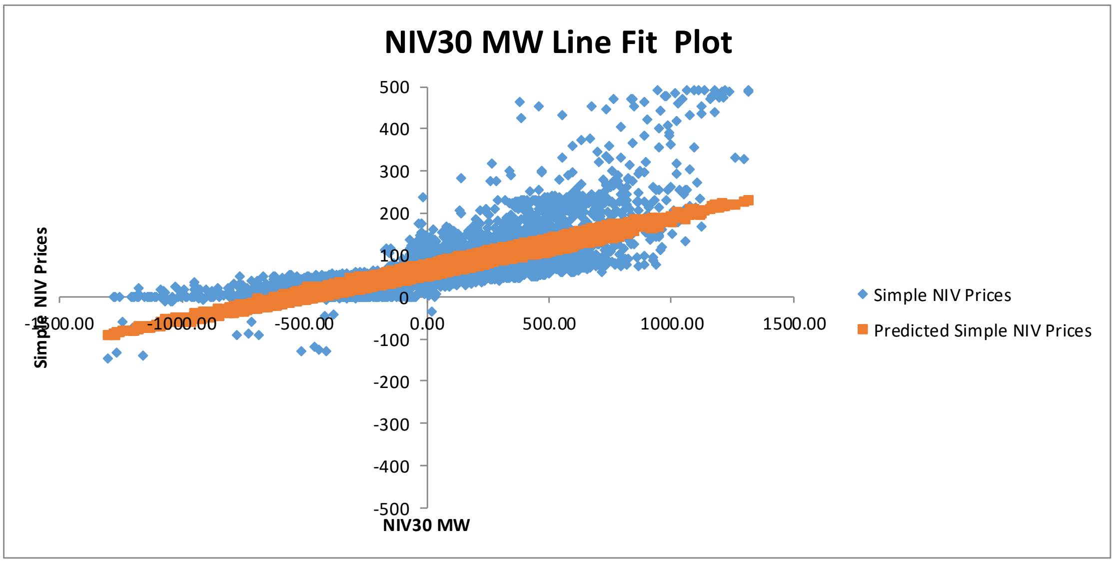


Figure 52

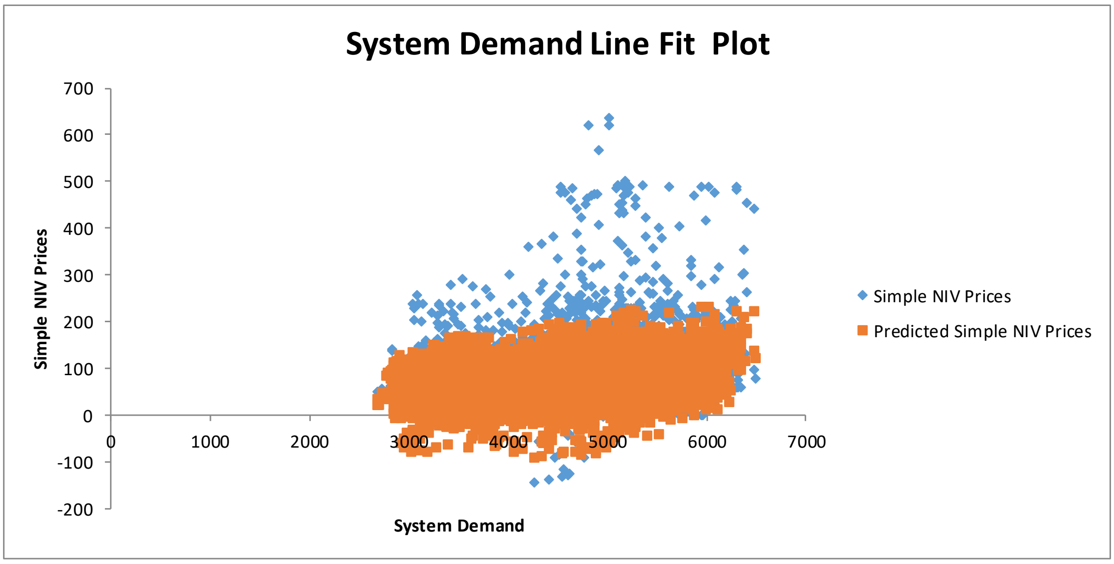


Figure 53

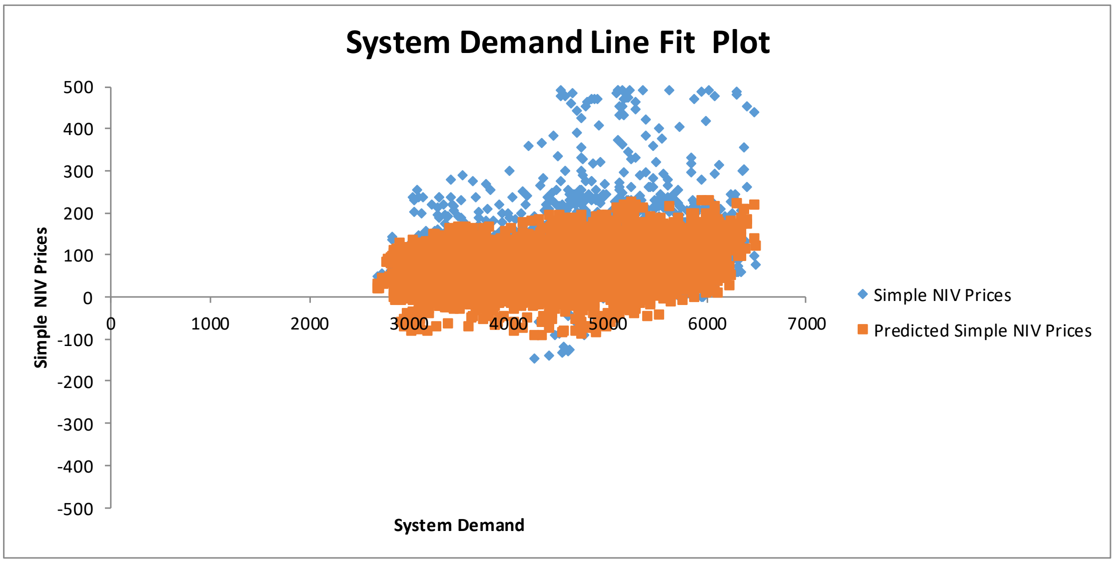


Figure 54

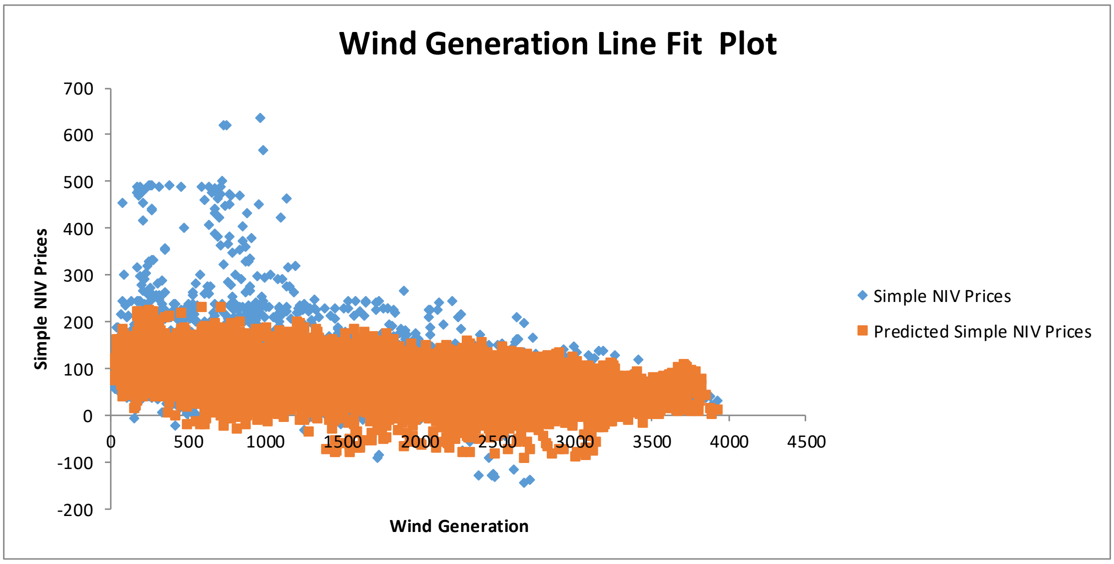
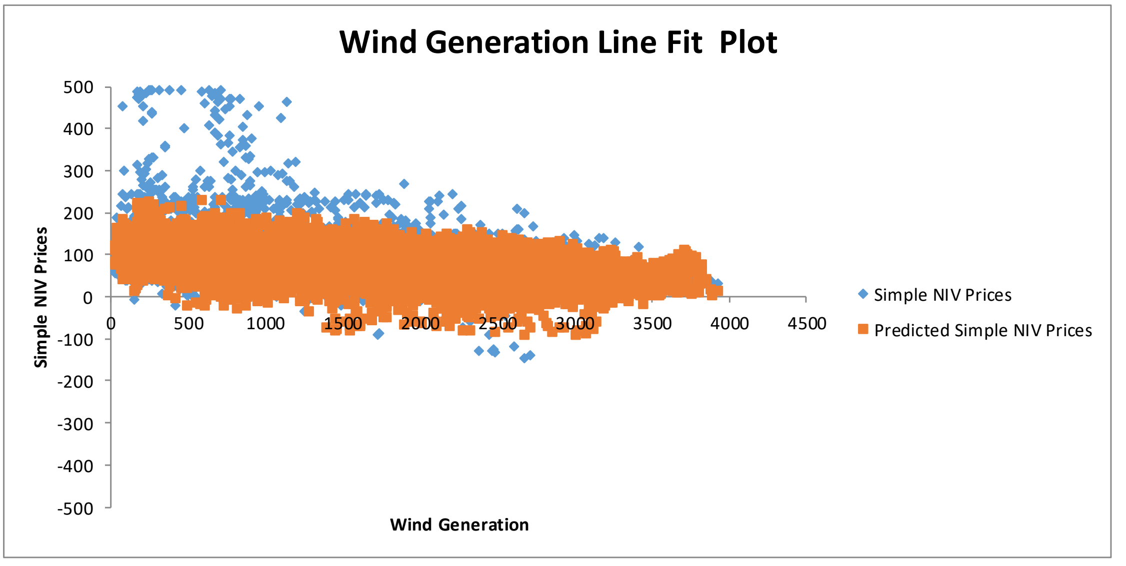


Figure 55



Simple NIV Prices vs NIV (MW) & System Demand

Table 16

Adjusted R Square	0.516
P-value: NIV (MW)	0.00
P-value: System Demand	0.00

Simple NIV Prices vs NIV (MW)

Table 17

Adjusted R Square	0.509
P-value: NIV (MW)	0.00

Simple NIV Prices vs System Demand (MW)

Table 18

Adjusted R Square	0.043
P-value: System Demand	0.00

Simple NIV Prices vs Wind Generation (MW)

Table 19

Adjusted R Square	0.125
P-value: Wind Generation	0.00

Regression analysis was also carried out on:

- The difference between the original imbalance price and the DAM price against the NIV;
- The difference between the original imbalance price and the BackUp price against the NIV;
- The difference between the Simple NIV price and the DAM price against the NIV; and
- The difference between the Simple NIV price and the BackUp price against the NIV.

The detailed results are outlined below. At a high level, the NIV explains more than twice as much of the variation in the difference between the Simple NIV price and the DAM price, than the variation in the difference between the original imbalance price and the DAM price.

(Original Imbalance Price – DAM Price) vs NIV (MW)

Table 20

Adjusted R Square	0.142
P-value: NIV (MW)	0.00

Figure 56

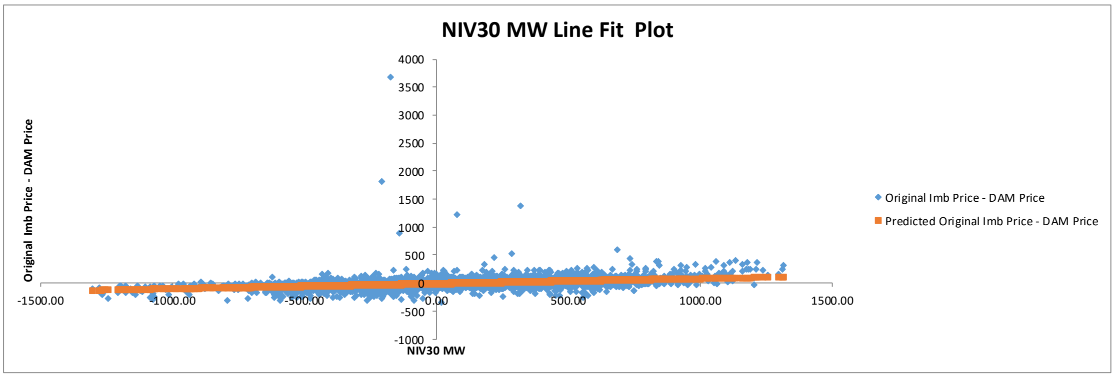
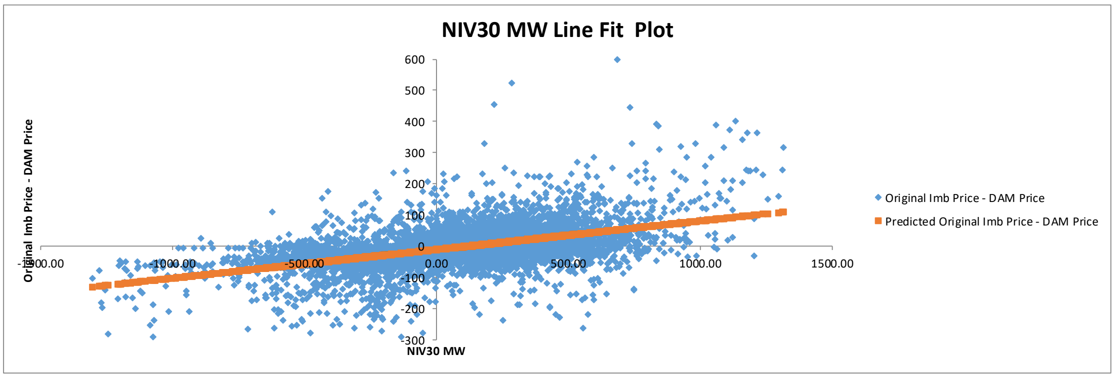


Figure 57



(Original Imbalance Price – BackUp Price) vs NIV (MW)

Table 21

Adjusted R Square	0.155
P-value: NIV (MW)	0.00

Figure 58

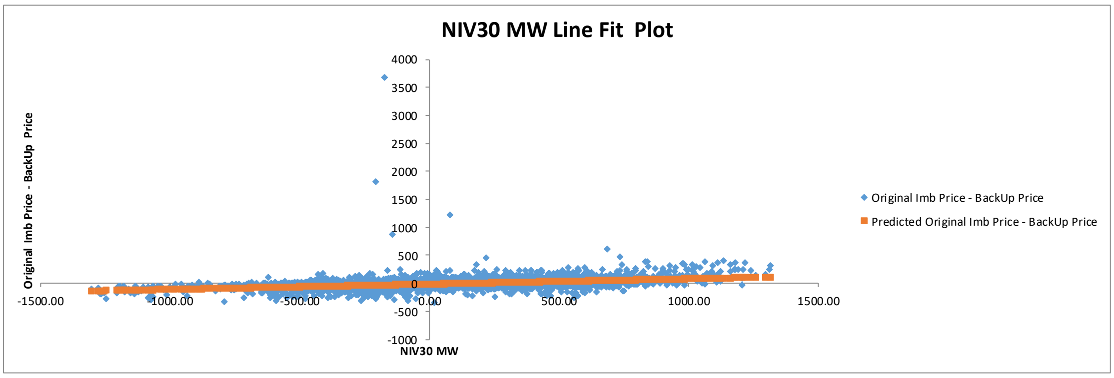
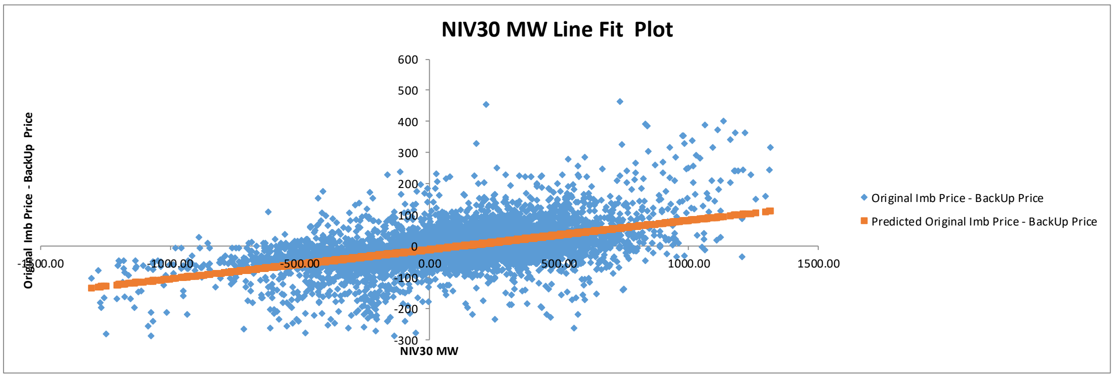


Figure 59



(Simple NIV Price – DAM Price) vs NIV (MW)

Table 22

Adjusted R Square	0.309
P-value: NIV (MW)	0.00

Figure 60

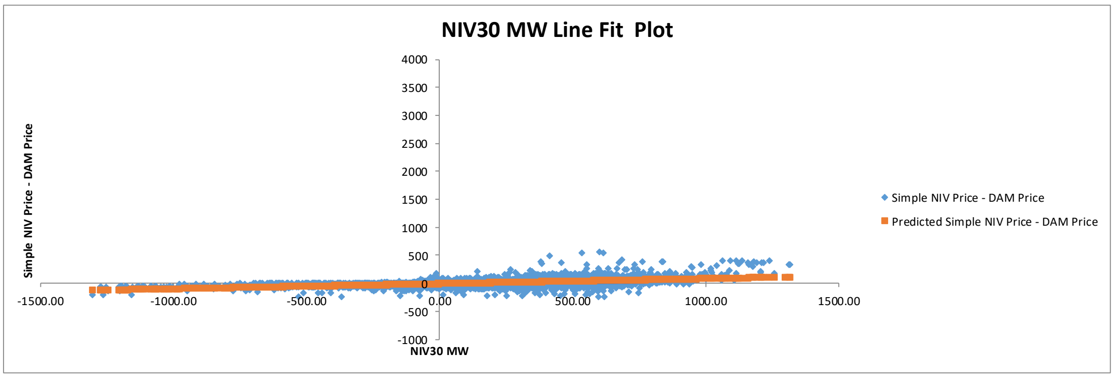
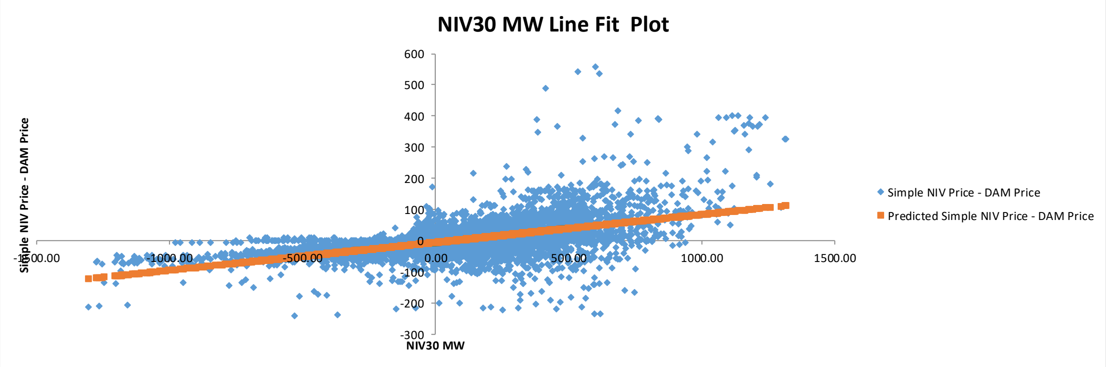


Figure 61



(Simple NIV Price – BackUp Price) vs NIV (MW)

Table 23

Adjusted R Square	0.324
P-value: NIV (MW)	0.00

Figure 62

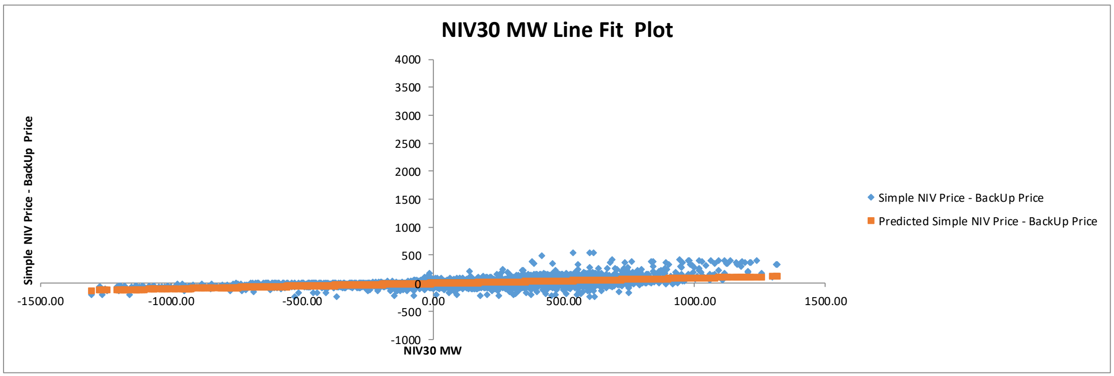


Figure 63