Report on the Imbalance Prices calculated on 24/01/2019	February 21

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2 INTRODUCTION

The purpose of this document is to provide a report to Participants and Parties to the SEM on the Imbalance Settlement Prices published for the Trading Day of January 24th 2019. This document is intended to outline the drivers behind operation of the balancing market on the specific Trading Day, actions taken by the Transmission System Operators (TSOs) over the course of the Trading Day, how these actions were treated in the flagging and tagging process and how these ultimately fed into the Imbalance Price and Imbalance Settlement Price calculations.

3 EXECUTIVE SUMMARY

On January 24th across the lunch time period, the five minute Imbalance Price determined by SEMO in its role as Market Operator exceeded the strike price of €500 in eleven Imbalance Pricing Periods as shown in the graph below.

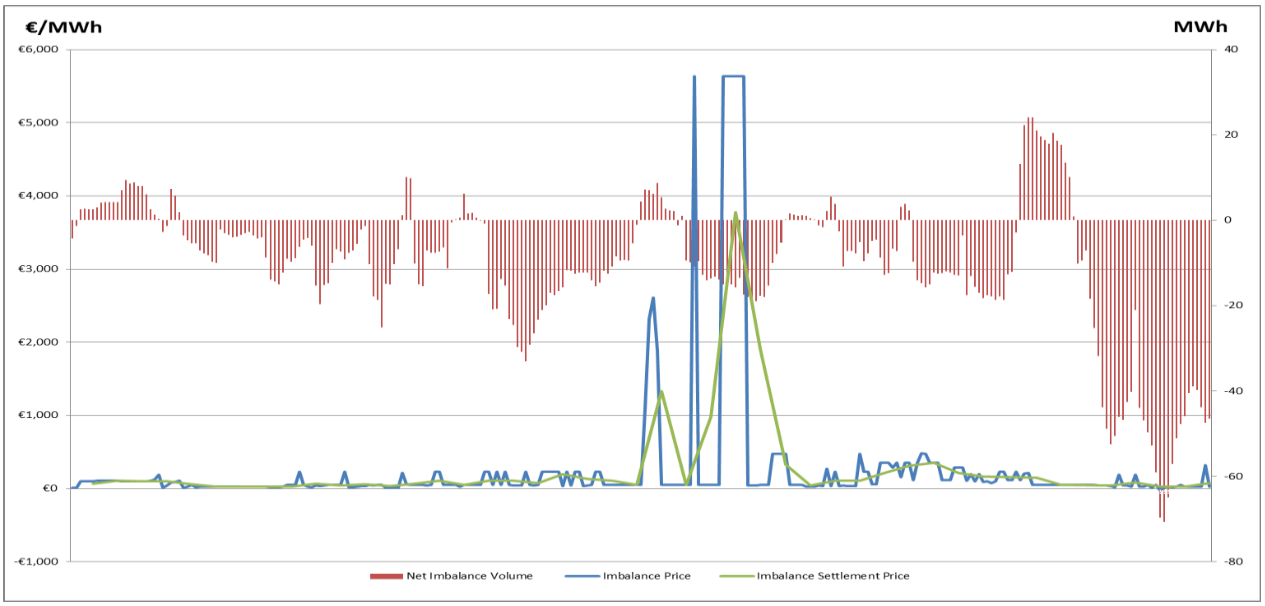


Figure 1 - Imbalance Prices (5 and 30 minute) with Net Imbalance Volume on Jan 24th 2019

This resulted in the half-hour Imbalance Settlement Price at levels above the strike price in four Imbalance Settlement Periods.

EirGrid, SONI and SEMO have undertaken a detailed examination of the events leading up to and during January 24th which are laid out in more detail in this report.

The following is the sequence of events that has been observed.

Wind forecast, based in the ROI jurisdiction was traded in the ex-ante market which does not take account of inter-area transfer restrictions. Because the price spread between SEM and BETTA was tighter in the day-ahead market, this resulted in Moyle being utilised to export form the SEM ahead of EWIC due to the application of losses in the ex-ante auction algorithm. The additional intraday auctions continued to reflect the positions from the day-ahead market increasing the level of export to the GB system.

Plant outages coupled with low wind in Northern Ireland and full exports on the Moyle interconnector meant the system was highly constrained and security standards resulted in the North South tie-line being flagged as binding constraint for much of the periods affected.

When the tie-line constraint is binding, this means that generators (including Demand Side Units) on the exporting side of the tie-line are flagged by the constraint. This is because while the constraint is binding in a South to North direction, as it did on the day, no unit in ROI can solve a marginal increase in system load anywhere in the SEM; they can only solve increases in the ROI area. Only generators in NI can solve a marginal increase is system load anywhere in the SEM.

This resulted in a high priced unit which was synchronised for system reasons and kept at minimum output becoming marginal when the TSOs dispatching algorithm took this as the next cheapest unflagged action available in the stack to meet an energy imbalance, setting the five minute price at €5,636.62 for a number of Imbalance Pricing Periods.

A detailed review of the flagging of units in the system outputs has shown that flags were applied correctly and none of the known defects in the Imbalance Pricing algorithm impacted in the relevant periods.

SEMO undertook to provide detail on the event to Market Participants. This report provides Participants with that additional detail on how the operation of the system and market on this day. This document is set out in five significant sections as follows –

- Ex-ante markets – setting out the operation of SEMOpx markets and the outputs that resulted;
- Conditions before the Pricing Event – a review of conditions on the power system in the lead up to the lunch time period;
- Actions taken by the TSO – a chronology of the TSOs actions and when they were taken;
- Treatment of TSO actions – going through how the actions described impacted on the calculation of the Imbalance Price;
- Review of the Application of Flagging and Tagging – outlines the detailed analysis that was undertaken by SEMO to ascertain that flags and tags were correctly applied.

The report concludes that the Imbalance Prices on this date were calculated correctly and in accordance with the rules set out in the Trading & Settlement Code, which implements the detailed design decisions of the SEM Committee, and the Transmission System Operator's Methodology for Determining System Operator and Non-Marginal Flags.

EirGrid, SONI and SEMO will further engage with Participants on this event and will endeavour to further deal with Participants questions. EirGrid, SONI and SEMO are committed to further engagement with the Regulatory Authorities.

4 EX-ANTE MARKETS

The ex-ante auctions and continuous trading market operated by SEMOpx functioned normally for the Trading Day of 24/01/2019. Participation in the day-ahead market followed patterns of behaviour consistent with how the ex-ante markets have operated thus far. This reveals itself with high levels of purchases by Supplier Units (retail companies) in the day-ahead market followed by smaller levels of re-trading in the intraday auctions and continuous market. It is worth noting that participation in the continuous market and the final (local) intraday market following the high imbalance prices was higher than normal.

At the day-ahead market, Supplier Units completed the bulk of their trading with almost all of system demand being purchased in the day-ahead market, in many cases with the ex-ante market clearing long. Of purchases bid into the day-ahead market, Supplier Units cleared on average 97% of the volume offered to trade, shown below.

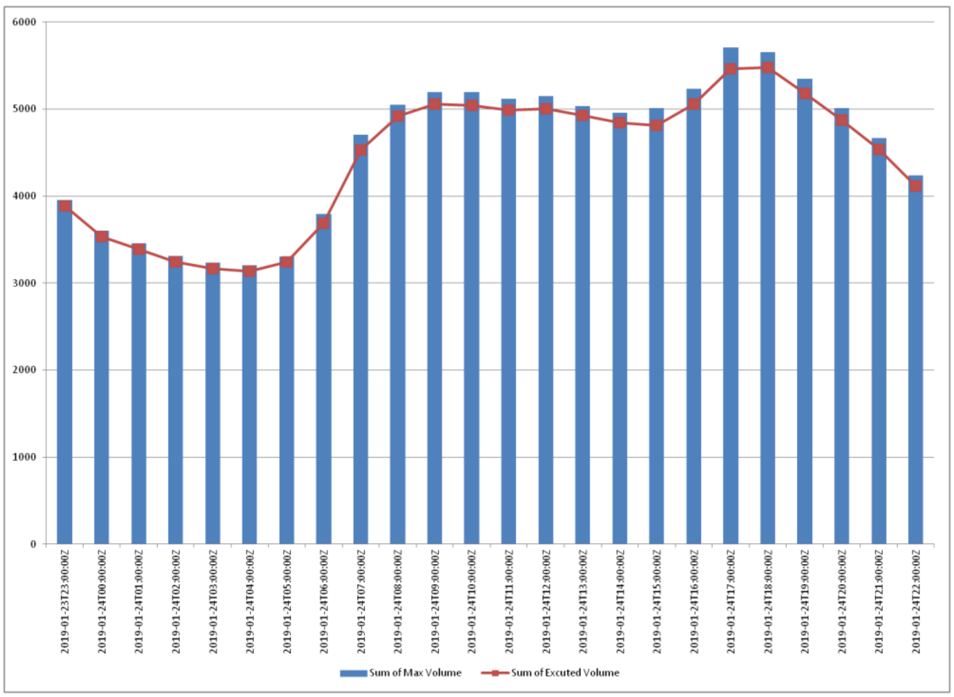


Figure 2 - Volume of purchase bids into day-ahead market vs. bids cleared

Given the wind forecast versus load forecast, trading represented lower cost generation across the Trading Day and the ex-ante markets resolved with more production cleared than consumption in a number of trading periods. This production surplus drives exports from the SEM to adjacent coupled markets across the Moyle and EWIC interconnectors. Due to the application of losses in the Euphemia algorithm, this results in the Moyle interconnector being scheduled first until the price spread between the SEM and any coupled markets exceeds the loss value on both interconnectors.

Across the peak periods, it can be seen that SEM price is generally cheaper than the GB price. This reflects conditions on the day where the GB system was equally highly constrained and experiencing similar operational conditions to the Irish and Northern Irish system.

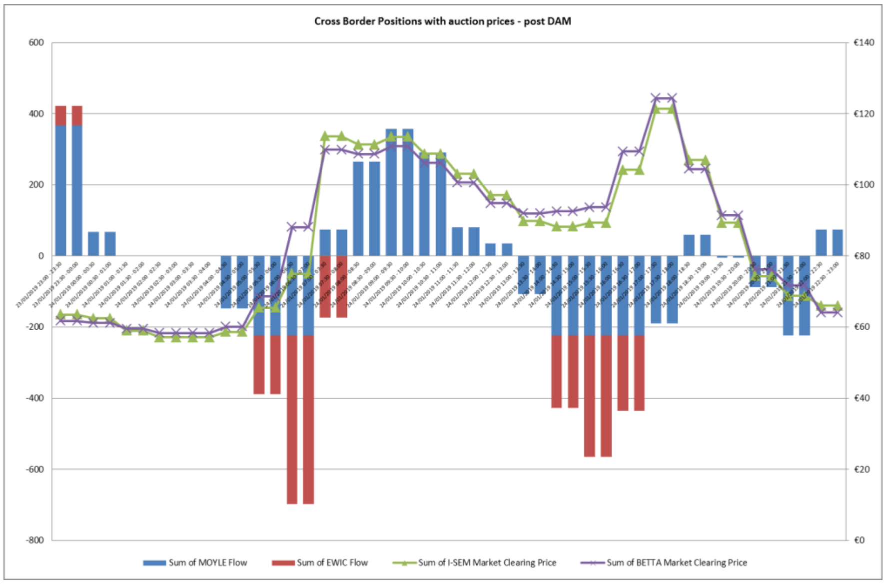
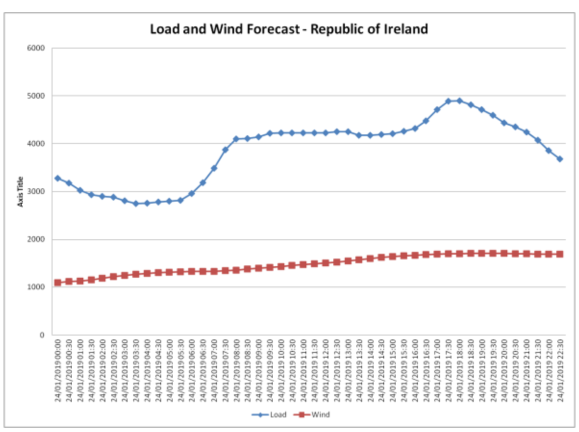


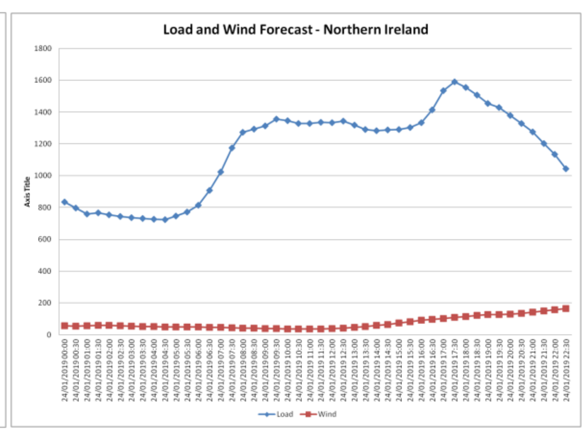
Figure 3 - DAM results, cross border flows with auction prices

As the north south tie-line is modelled as an unlimited inter-area transfer in the ex-ante markets, this means that the ex-ante markets do not recognise any restriction on exports from the SEM based on location. This resulted in high levels of export being scheduled first on the Moyle interconnector effectively representing an export of wind production; however, the wind on the power system was based in the ROI region with very little wind generation available in Northern Ireland across the lunchtime period to meet the scheduled exports.

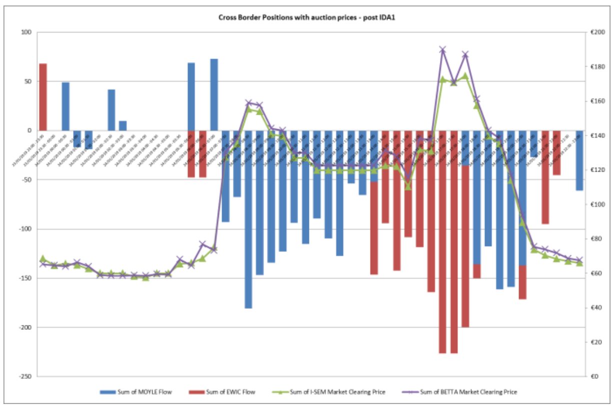
Figure 3 above shows the interconnector flows after the day-ahead market (DAM). Moyle was scheduled to import between 23:00 and 00:59, switching to export from 04:00 to 06:59, back to import between 07:00 and 12:59, back to exporting from 13:00 to 17:59, importing for the next hour, exporting between 19:00 and 21:59 and returning to importing for the last hour of the Trading Day.

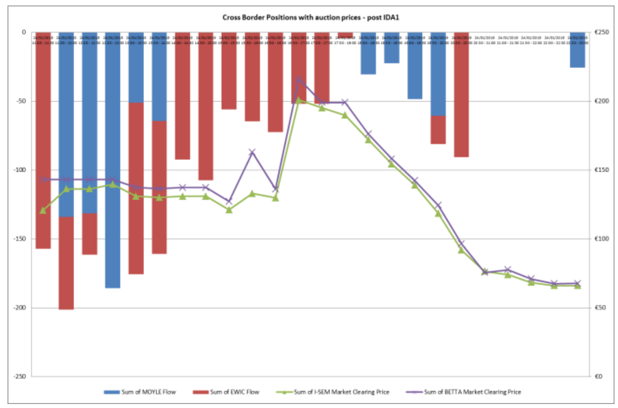
The graphs below show the load and wind forecast in each jurisdiction as input into the TSO scheduling tools across the trading day.





As the ex-ante markets continued with additional coupled auctions, the general conditions observed between SEM and BETTA persisted, with SEM prices resolving cheaper than the corresponding BETTA prices across the latter half of the day. The result of this is that each subsequent auction scheduled further exports to the GB system, effectively increasing the level of exports on Moyle while still not cognisant of the locational restrictions within the Irish and Northern Irish power system. This further reversed the initial DAM positions on Moyle resulting in the interconnector exporting from an earlier time of 11:00 continually up to 22:00.





This led to high exports being scheduled on both interconnectors from the ex-ante markets. Closer spreads between the SEM and GB clearing prices ensured that Moyle is scheduled fully when there is still capacity available on EWIC.

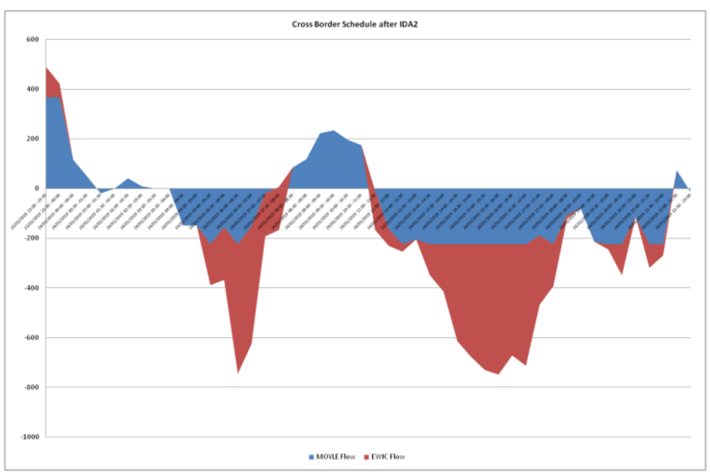


Figure 4 - Cross border power flows after IDA2

The SEM itself appeared balanced with sufficient production, consumption and cross border flows as the graph below demonstrates.

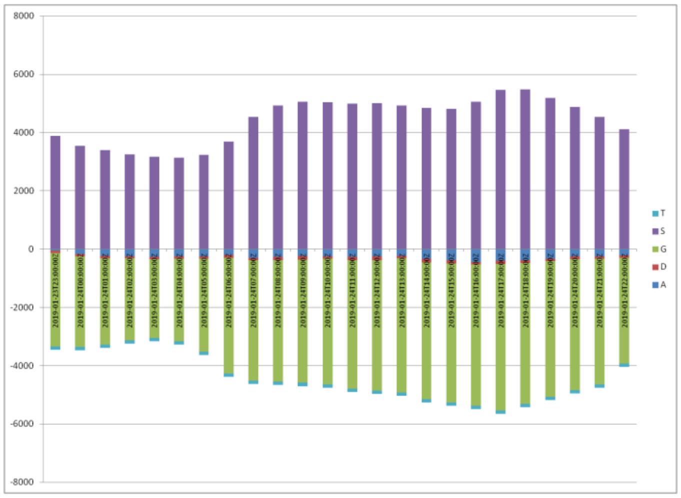


Figure 5 - Day--ahead market results for the SEM[1]

Within each jurisdiction, the market results were not as balanced. The graph below shows the resolution of the market relative to the Northern Ireland jurisdiction after the day-ahead auction.

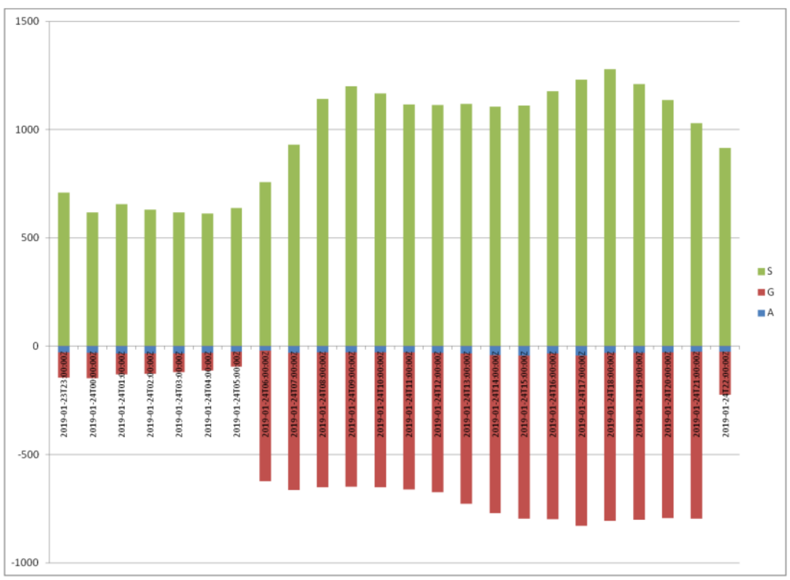


Figure 6 - Day-ahead market results for NI only

This shows expected levels of consumption in Northern Ireland; however, a much lesser level of generation is scheduled to meet this. Also, to be considered is the exports on Moyle which further increase the consumption in the latter part of the day.

These market positions feed into the Physical Notifications submitted to the TSO by generators and demand side units giving the TSOs a starting point for scheduling based on a jurisdictionally imbalanced market.

[1] T = Trading Unit, S = Supplier Unit, G = Generator Unit, D = Demand Side Unit, A = Assetless Unit

After high imbalance prices were observed across the lunchtime period, there was additional trading activity in the third intraday auction (IDA3) and in the continuous market. Traders entered additional "buy" positions with the result that the market ultimately resolved long (more generation cleared than actual load).

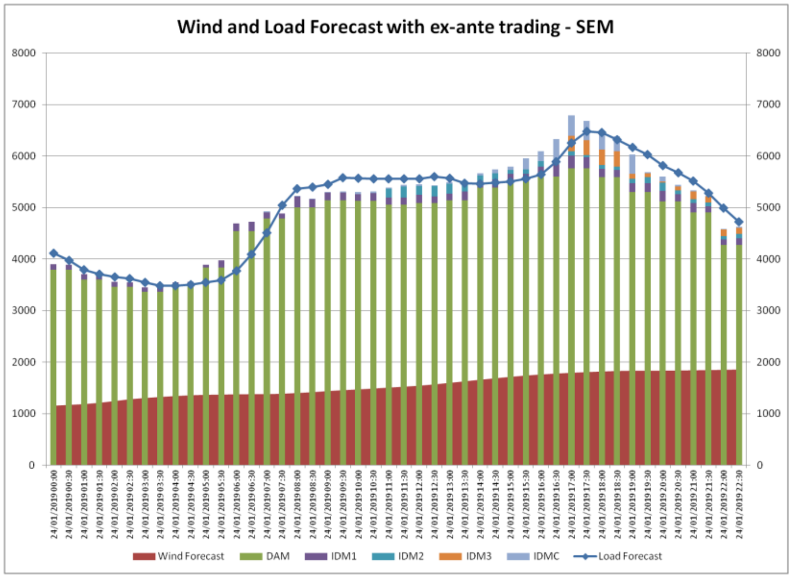


Figure 7 - Wind and load forecasts with ex-ante market results

5 CONDITIONS BEFORE PRICING EVENT

At 05:02 on the 23/01/2019 the unit GU_500040 (C30) declared unavailable due to a technical issue, and it would subsequently remain unavailable for three days. The total output of the wind farms in NI on the 23rd was low, with a maximum of 111 MW and minimum of 48 MW. The Moyle interconnector was importing 450MW from GB for most of the day. With these operating conditions, all available conventional NI generation was scheduled to meet the NI demand.

On the 23/01/2019 following the publication of the Day ahead ex-ante market results for the 24/01/2019 SONI identified that the NI system could potentially be in an alert situation on the 24th. The same conventional generation remained available as the 23rd but the Moyle interconnector was scheduled to be exporting in excess of 200MW to GB over the lunch time and evening peak demand periods. In order to reach the scheduled export values the interconnector had to start moving to an export position from 11:00. The forecast NI wind was low with a minimum of 8 MW in the morning period and the potential to reach approximately 250MW over the evening peak demand period. The Ireland wind forecast was much higher than the NI wind forecast for the 24th and as the day-ahead ex-ante market does not consider the North to South tie line restrictions this resulted in a schedule with as much export on Moyle as possible before scheduling flow on EWIC, due to the application of losses in the ex-ante auctions. The Moyle export capacity is determined on a daily basis by National Grid in GB and SONI and can range from 80MW to 295MW on a given day, on the 24th the export capacity was 219MW into GB.

On the 24/01/2019 the Intra-day ex-ante market results confirmed, and indeed increased, the Moyle export to GB, starting at 11:00 and peaking at 219MW export into GB on three periods namely 12:23, 13:00 to 17:00 and 17:30. These periods include the lunch time and evening peak demand periods in NI. The NI wind remained low in the early part of the day as per forecast and was even below forecast for most of the morning. The wind in Ireland was above forecast for most of the day but could not be used to help support the Moyle export or the demand in NI due to the tie line operational limits. The Ireland to Northern Ireland flow on the tie line schedules indicated that the maximum achievable south to north stable operational flows were occurring for large periods of the day. In order not to breach the stable operational limits on the tie line the indicative operational schedules indicated the need to start the majority of NI fast start units when Moyle was at its maximum export position during the day.

Having considered all of the information available at the time the TSO considered it prudent to issue an Amber alert 1 to all system participants. In the initial alert message the indication was that the alert would end at 19:00. Subsequently as system conditions improved, largely due to a reduced system demand and a higher than expected wind output the alert was withdrawn at 18:45. The sequence of events is included in the following section.

6 ACTIONS TAKEN BY THE TRANSMISSION SYSTEM OPERATOR

The text below represents a factual log of the TSO events on the day.

Time	Action
08:45	LTS run initialised following publication of IDA2 Interconnector schedules
09:15	Indicative schedule highlighted considerable constraints to meet NI demand due to plant unavailability, South to North tie-line constraints (restricted for dynamic stability) and sizeable flows to Scotland on Moyle (between 155 – 220 MW). Study runs were initialised assuming that a CBB trade of 200MW (GB to NI net) could be facilitated.
09:20	LTS Study run undertaken to ascertain the benefits of dispatching the units GU_500822 (K1) and GU_500823 (K2) onto secondary fuel. The reason for the study was because the units provide a larger MW output on secondary fuel.
09:30	Phone call occurred between SONI Grid Control Engineer and National Grid to discuss potential CBB trades for periods between 11:00 to 14:00, and 16:30 to 18:30. Due to system conditions in GB, National Grid declared that they were not in a position to trade and the proposed trade could not be facilitated.
09:36	GU_500822 (K1) and GU_500823 (K2) instructed to transfer to secondary fuel from 15:31 to provide increased active power capacity. The notification time for the changeover to secondary fuel is six hours so instructions issued at this time to have the increased output available for the peak demand period in the evening.
10:05	Final LTS run published without any Interconnector trading proposed but with the intention to dispatch the two units GU_500822 (K1) and GU_500823 (K2) onto secondary fuel.
10:17	Subsequent RTC run advised starts for various Open Cycle Gas Turbines in Northern Ireland including GU_500283 BGT1 (11:15) and GU_500284 BGT2 (11:45), primarily for provision of system services but some periods indicate that active power contributions would be necessary. Only DSU_501460 (ECA) was proposed to be brought on by RTC from 11:15 to 12:00 with a maximum contribution of 4MW.
10:26	GU_500820 (KGT3) and GU_500821 (KGT4) synchronised for operational reasons. Real time assessment tools indicated potential instability issues for increased South to North flows on the tie line requiring generation to be scheduled in NI.
10:55	GU_500284 (BGT2) started for NI operational reasons as real time assessment tools had indicated large frequency deviations in NI for the loss of the tie line.
11:20	GU_500283 (BGT1) started for NI operational reasons as real time assessment tools had indicated large frequency deviations in NI for the loss of the tie line. .
11:30	Amber Alert 1 issued for Northern Ireland. This included updating the European Awareness System for the island of Ireland.
11:31	SONI Switching engineer contacted National Grid counterpart to remove the Emergency Assistance service from NI to GB on the Moyle for the duration of the Amber Alert 1.
12:25	GU_500041 (CGT8) tripped.
13:29	GU_500283 (BGT1) de-synchronised as actual system conditions permitted.
13:34	GU_500284 (BGT2) de-synchronised as actual system conditions permitted.
14:11	GU_500041 (CGT8) started for operational reasons

Time	Action
15:08	LTS run published. In this run the technical output requirements to return the units GU_500822 (K1) and GU_500823 (K2) to secondary fuel was included.
15:49	GU_500823 (K2) transferred to secondary fuel to provide increased active power capacity.
16:00	GU_500822 (K1) transferred to secondary fuel to provide increased active power capacity.
16:23	GU_500283 (BGT1) and GU_500284 (BGT2) started for operational reasons
16:10	DSU_501450 (AEA) and DSU_501330 (PH1) started
16:15	DSU_501510 (ETB) started
16:30	DSU_501380 (ETR) started
16:39	GU_501230 (AGU) and GU_501230 (EMP) started
16:40	DSU_501200 (ACA) and DSU_501600 (ETD) started
17:29	NI peak evening demand (1520MW) was 70MW lower than previously forecast while generation from renewables was 60MW higher than forecast due to changing weather conditions.
17:59	DSU_501380 (ETR), DSU_501510 (ETB), DSU_501600 (ETD), DSU_501330 (PH1), DSU_501450 (AEA), DSU_501200 (ACA) desynchronised
18:36	GU_501230 (EMP) desynchronised
18:45	Northern Ireland Amber Alert 1 removed.
19:30	LTS run published.
19:59	GU_500283 (BGT1) de-synchronised as actual system conditions permitted.
20:07	GU_500284 (BGT2) de-synchronised as actual system conditions permitted.
20:29	GU_501230 (AGU) de-synchronised as actual system conditions permitted.
21:44	GU_500820 (KGT3) de-synchronised as actual system conditions permitted.
21:53	GU_500821 (KGT4) de-synchronised as actual system conditions permitted.
23:14	GU_500823 (K2) returned to primary fuel.
02:23	On the 25/01/2019 GU_500822 (K1) returned to primary fuel.

7 TREATMENT OF TSO ACTIONS IN THE FLAGGING & TAGGING PROCESS

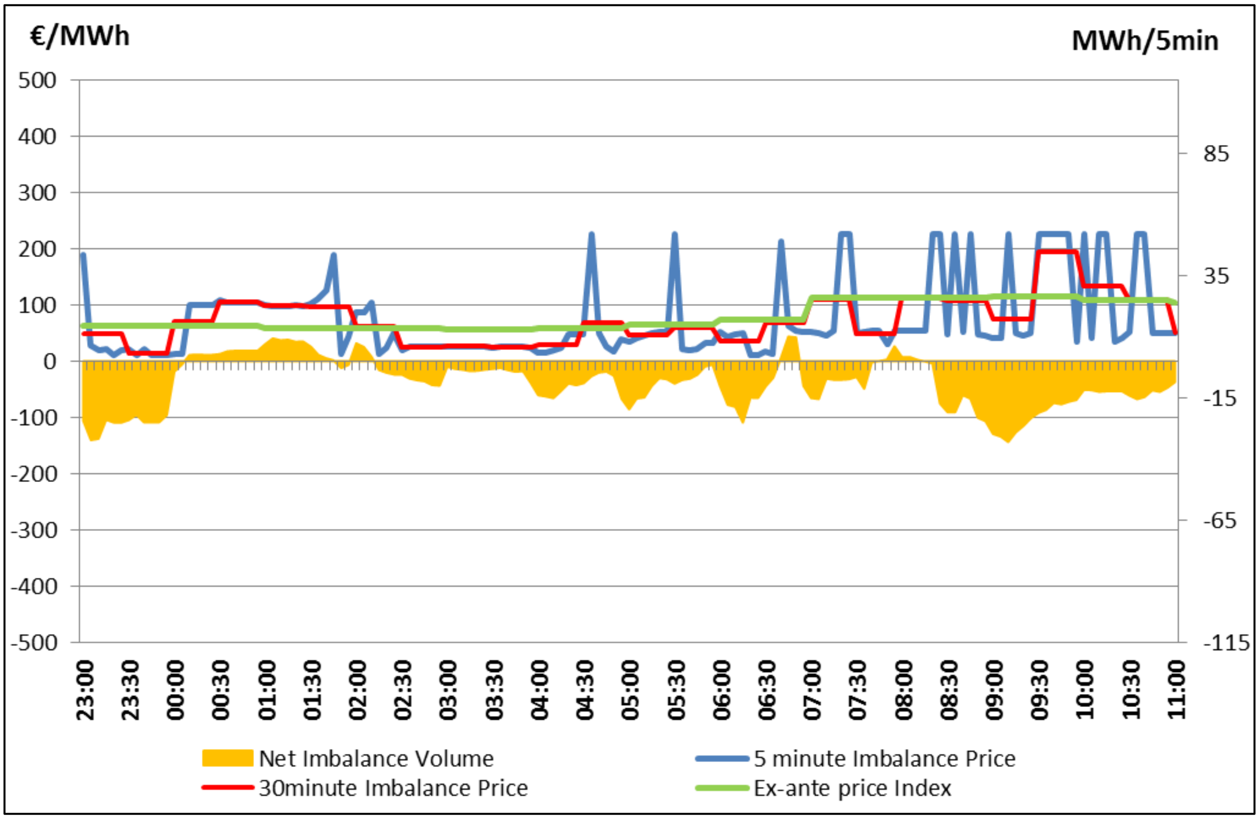


Figure 8 - Imbalance Price with NIV

Conditions on system

As described in the previous section, the conditions on the system were highly constrained. Due to the results of the ex-ante auction, the Moyle interconnector was scheduled to be exporting throughout the day. This resulted in ROI units exporting energy to NI causing the constraint MWR to be binding on the all ROI units for the majority of the day.

MWR Constraint

Scheduled flows between the Ireland and Northern Ireland systems are limited by constraints to ensure they do not exceed the limitations of the North-South tie line, including a 20 MW margin of safety. It takes into account the rescue/reserve flows that could occur immediately post-fault inclusive of operating reserve requirements.

For positive flows from South to North:

$$T_{S-N} + Min(POR_{IE}, LSI_{NI} - 25\%\ POR_{NI}) \leq S\_MWR\_ROI\ - 20\ MW\ Margin\ of\ Safety$$

For positive flows from North to South:

$$T_{N-S} + Min(POR_{NI}, LSI_{IE} - 25\%\ POR_{IE}) \leq S\_MWR\_NI - 20\ MW\ Margin\ of\ Safety$$

Where:

- $T_{S\text{-}N}$ is positive scheduled flow from South to North across the North-South Tie Line, i.e., the scheduled generation in Ireland less the scheduled demand in Ireland;
- $T_{N\text{-}S}$ is positive scheduled flow from North to South across the North-South Tie Line, i.e., the scheduled generation in Northern Ireland less the scheduled demand in Northern Ireland;
- POR_{IE}/POR_{NI} are the scheduled Primary Operating Reserves in Ireland/Northern Ireland (including dynamic reserve, interruptible load and interconnector reserve);
- LSI_{IE}/LSI_{NI} is the scheduled MW output of the Largest Single Infeed in Ireland/Northern Ireland; and
- S_MWR_ROI/S_MWR_NI are the maximum allowed flows including rescue/reserve flows that could occur immediately post-fault inclusive of operating reserve requirements.

The reserve capacity needed on the North-South tie line to address a fault in a jurisdiction is the amount that must be able to flow across the tie-line in the event of the loss of the largest single infeed in the jurisdiction. It is calculated as the lesser of:

1. the primary operating reserve in the other jurisdiction; and
2. the largest single infeed in the jurisdiction less 25% of the primary operating reserve in the jurisdiction

Where the S_MWR_ROI or S_MWR_NI constraints are binding, any unit that is contributing to the constraint will be flagged. For example, if the S_MWR_ROI constraint is binding then all Ireland units are SO flagged as an increase in these units' Scheduled Output would increase $T_{S\text{-}N}$ and breach the constraint. An exception to this is when POR_{IE} is less than (LSI_{NI} – 25% POR_{NI}), an Ireland unit has a POR decrement rate of -1 and scheduled at a MW level whereby a change in its MW output would reduce the unit's POR. In this case the Ireland unit is not SO flagged because an increase in MW output would reduce its POR provision proportionally which would not lead to a breach of the constraint. If (LSI_{NI} – 25% POR_{NI}) is less than POR_{IE} then the Largest Single Infeed(s) in Northern Ireland, and any Northern Ireland unit that is scheduled at a MW level whereby a change in their MW output would reduce the unit's POR will also be SO flagged. The converse applies to S_MWR_NI.

PMEA Calculation

These conditions on the system coupled with the market being long, resulted in the extreme fluctuation in the imbalance price throughout the day. This fluctuation was cause by two key components of the Trading & Settlement Code (E.3.4); the price of the marginal energy action and the replaced bid offer price.

If the Net Imbalance Volume (NIV) is positive, the market is said to be short. This mean more incs have been taken and the higher the price of the inc the more expensive it is (i.e., the more has to be paid to a unit to increase generation). The marginal energy action becomes the most expensive unit that is neither SO nor Non-marginal flagged. This will become the Price Marginal Energy Action (PMEA). If a unit with more expensive Commercial Offer Data than the PMEA has been either SO or Non-Marginal flagged, its price is replaced by the PMEA (This is known as the Replaced Bid Offer Price).

If the NIV is negative the market is said to be long, this mean more decs have been taken and the lower the price of the dec the more expensive it is (i.e., the less is paid by the unit, or the more is paid to the unit, to reduce generation). The marginal energy action becomes the cheapest unit that is neither SO nor Non-marginal flagged. This again becomes the PMEA. If a unit with cheaper Commercial Offer Data than the PMEA has been either SO or Non Marginal flagged its price is replaced by the PMEA.[2]

PMEA on morning of 24th

The higher prices seen throughout the early morning (i.e., above €200) were the result of this happening. These prices were brought about as a result of all but one of the units in the bid stack been flagged, leaving GU_500822 to set the minimum PMEA and the Replaced Bid Offer Price at €226. Throughout the morning this unit was moved around in the indicative operating schedule resulting in it becoming marginal at times. It was at these periods where the higher price occurred.

This unit can at times be seen to have the constraint S_MWR_ROI binding against it. In these instances, this unit is the Largest Single Infeed in NI and will determine the magnitude of post fault flows on the North South. On this basis, it is SO flagged.

Instances of expensive units setting the PMEA while the all-island market is long has been a common occurrence in the balancing market since the transition to the new arrangements. A number of plant outages during the peak winter load had exacerbated this over the last month.

As a result of the System conditions in NI, the System Operators brought on two fast acting open cycle units GU_500283 & GU_500284. These units had simple COD in at 6,341 €/MWh and 5,636 €/MWh respectively.

Both these units were issued instructions to come on at their lower operating limit at 10:46 for an effective time of 10:55. The RTD schedule brought the units on at 11:15 and left them at their lower operating limit up on till 11:30.

[2] For more information on Marginal energy action see module 6 of Imbalance Price training material on the SEMO website, https://www.sem-o.com/training/modules/imbalance-pricing/Marginal-Energy-Action-Price.pdf

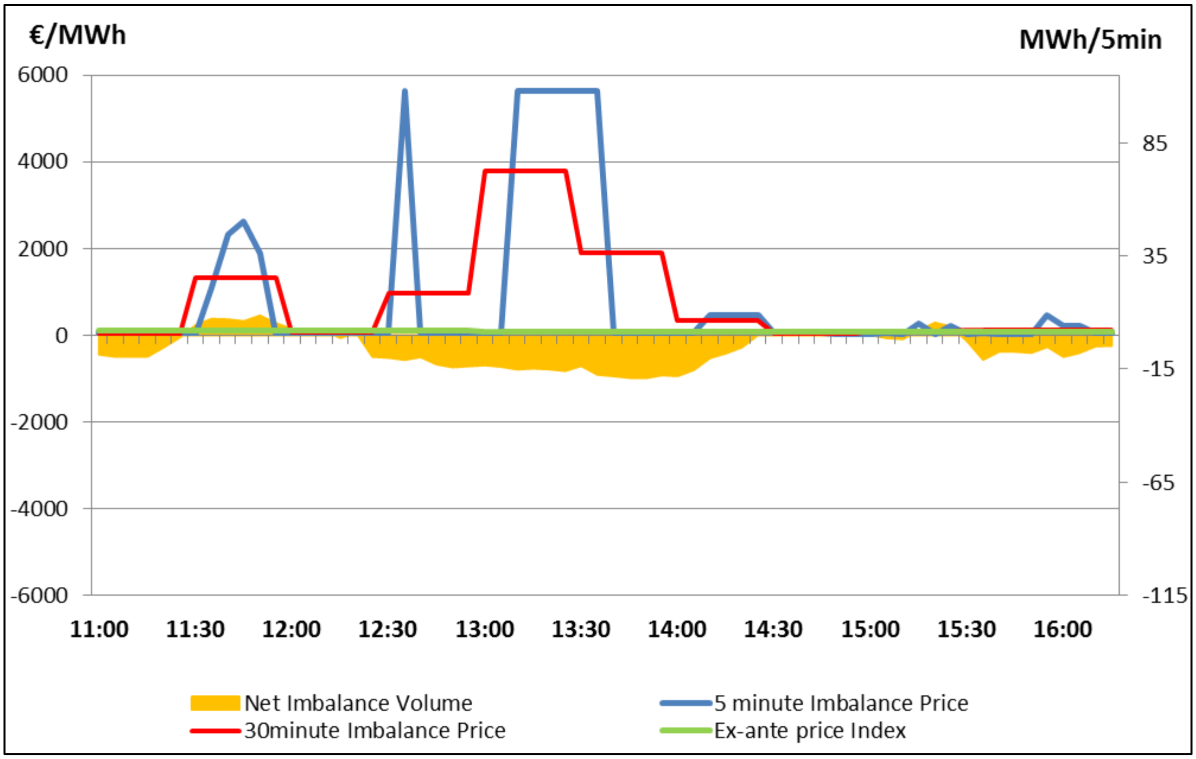


Figure 9 - Imbalance Price and NIV across lunch-time period

The first impact of the two units on pricing can be seen immediately after they come off their lower operating limit, becoming marginal at 11:35. During this period the all-island market is short. GU_500283 set the max PMEA for this period. As the most expensive unit in the bid stack, the replaced bid offer price had no impact on other offers as a result.

As part of the Price Average Reference (PAR), the 10 most expensive MWh making up the NIV are used to calculate the price. When the NIV is below 10MWh the most expensive un-flagged units that sum to the NIV are used in setting the price. Between 11:35 -11:50 GU_500283 & GU_500284 contributed 2.6 MWh of this with the remaining 4.3MWh coming from GU_400540. PAR worked as expected in this situation helping to dampen the impact of the high bid prices of the units on the imbalance price calculation.

Shortly after the initial high price event the all-island market switched from being short to long. During the next 40 minutes GU_500283 & GU_500284 were non-marginal flagged in the indicative schedule. This was the result of a ramp constraint against these units. Although the units are fast acting the schedule was trying to move it to a level above its dwell time breakpoint of 53MW. The unit must remain at this level for a 5 minute period as part of ramping to a higher output level and was therefore unable to get to the higher level intended by the schedule, resulting in it being non-marginally flagged for ramping.

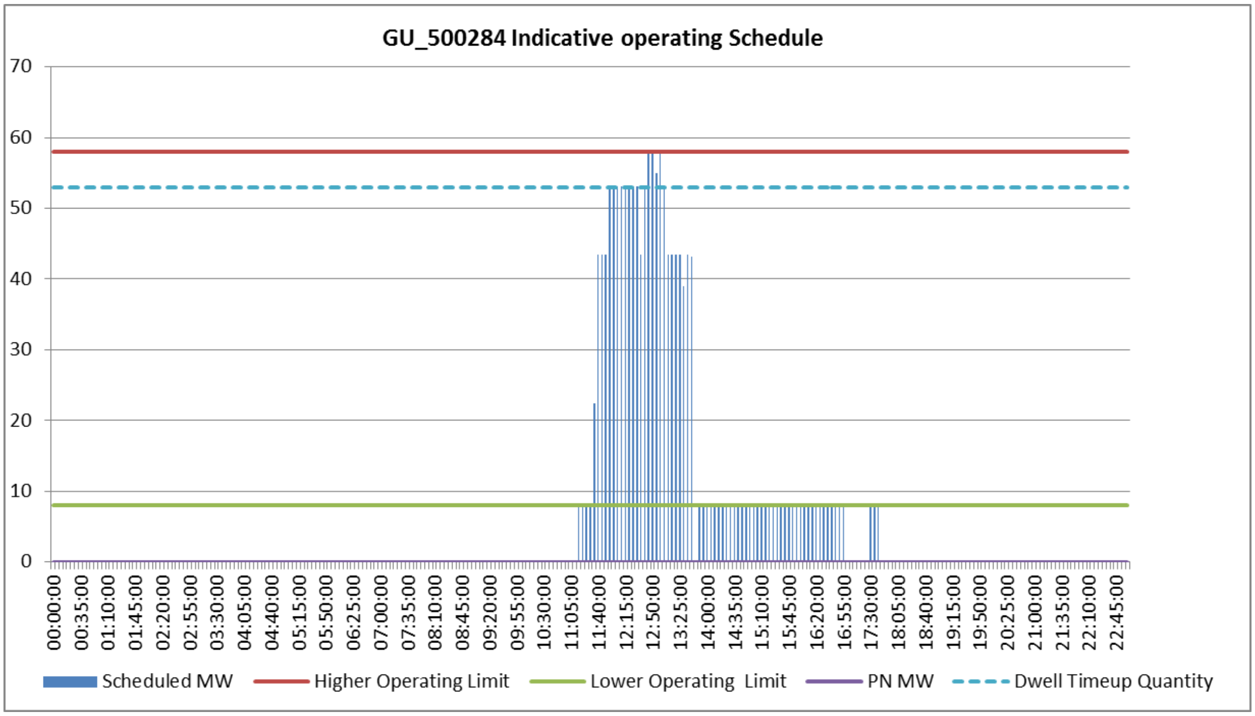


Figure 10 - Indicative Operating Schedule for GU_500284

Over this period all ROI units were flagged out because of the constraint S_MWR_ROI, while all NI units were being run at their operating limit, and being flagged as non-marginal. As a result the price is calculated by taking the most expensive 10MWh used in the NIV tag. The NIV tag is made up of only incremental or Inc values if the market is short and decremental or Dec values if the market is long. Multiplying the NIV tag by QBOA will equal the total imbalance on the system for a 5 minute period. Then, the 10 most expensive MWh of this is used in the determination of the imbalance price. This resulted in an imbalance price of circa €53 for these periods.

At 12:35 the indicative schedule moved GU_500824 away from its dwell time breakpoint for a 5 minute period. The bid stack had remained almost identical except for this unit becoming marginal. As a result GU_500284 set the min PMEA and the entire imbalance price at €5,636.[3]

For the next 30 minutes GU_500284 was either at its higher operating limit or ramp constrained, again becoming non marginal-flagged in the indicative schedule. This again resulted in all units in the bid stack being flagged out, resulting in the price being calculated directly from the NIV.

The physical conditions on the power system remained very consistent throughout this event. All ROI units remained SO flagged because of S_MWR_ROI, while all NI units were non-marginal due to been run at their operating limit. At 13:10 GU_500824 was moved off its operating limit for the next 30

[33] While this price exceeds the full Administered Scarcity Price, it should be noted that the ASP serves as a floor to imbalance prices during times of scarcity and not as a cap on the price. The Price Cap applied on the Imbalance Price is set per the SEMC decision SEM-17-046 at the Value of Lost Load (VOLL) (i.e., 10,000 €/MWh as set in 2007 and adjusted by inflation as per AIP-SEM-07-484).

minute in the indicative schedule, before being desynced at 13:35. This resulted in the GU_500824 becoming marginal and the only un-flagged unit in the bid stack for this window. GU_500824 set the PMEA, because when NIV is negative the marginal price is the lowest priced bid which is not Imbalance Price Flagged. The Replacement Bid Offer Price (PRBO) for all actions in the direction of the NIV became PMEA, because when NIV is negative PRBO is the maximum of the Bid Offer Price and PMEA. Therefore, the price after PAR tagging can be equal to the marginal price or higher. This caused GU_500824 to set the entire 5 minute imbalance price at 5,636 €/MWh for the next six pricing periods. These six periods affected two imbalance settlement prices resulting in prices of €3,773.69 and €1,909.45 respectively.

These two units were desynced just after 13:30. Pricing remained volatile with prices coming in much higher than a typical day and just below the strike price.

The high prices for the remainder of the day were the result of the same conditions on the system. GU_500821 had been run at its max operating limit for the high priced period. At 14:05 this became marginal resulting in it setting the min PMEA with a PBOA of€470. This and a number of other units fell in and out of pricing as a result of been moved off their operating limits in the indicative schedule.

GU_500823 changed its higher operating limit from 175 to 258MW at 16:05 due to the fuel switchover. This allowed the unit to become marginal for the majority of the evening. This unit began consistently setting the min PMEA with a PBOA of €353 during the evening peak. GU_500284 & GU_500283 were brought back on at around 16:16 over the evening peak. Both units were left at their lower operating limit over the period and thus remained flagged throughout. Other units were now un-flagged in the bid stack with cheaper prices which would have prevented either unit setting the min PMEA over the evening peak.

8 REVIEW OF THE APPLICATION FLAGGING & TAGGING IN IMBALANCE PRICE CALCULATION

Real Time Dispatch (RTD) is the TSOs' software used to provide indicative incremental and decremental dispatch decisions close to real-time for units which are on-line or scheduled to be on-line. The application uses a Security Constrained Economic Dispatch optimisation to produce MW dispatch advice based on real-time system conditions and forecasts for the next hour from close to real-time (10 minutes).

Every 5 minutes, the TSOs take a snapshot of a set of input data including Commercial Offer Data, Technical Offer Data, the commitment status of units as determined by the Real Time Commitment and Long Term Scheduling applications, and the physical output of units taken from State Estimators and run an RTD schedule. This produces a schedule at 5 minute resolution (i.e., a MW value for each unit is determined for each 5 minute interval) commencing 10 minutes after the run initiation time for a period of 1 hour.

The output of RTD is an Indicative Operations Schedule that is used to provide incremental and decremental dispatch advice. It does not make unit commitment/de-commitment decisions.

In this next section, we outline the analysis that were carried out on the outputs of the RTD and the Real Time Imbalance Pricing (RTPIMB) applications to confirm that flags and tags were correctly applied. In some cases, investigations identified circumstances where Participants may conclude from the data published that there may have been issues with the processes, for example where generator has all its actions flagged as non-marginal; however, we have identified other factors that bear on these results, confirmed that these are correct and endeavour to provide an explanation for the results that are being observed.

In the next section, the time referred to for an RTD run is the first five minute period in that run's optimisation horizon, e.g. if referring to the 11:10 RTD run this is the run that optimised schedule results for the periods from 11:10 to 12:10. When referring to the results in a specific period within the optimisation horizon, the term "scheduling period" is used.

8.1 REAL TIME DISPATCH (RTD) RUNS FOR FLAGGING INFORMATION

Multiple tests were carried out to verify that the System Operator Flags (SO Flags) and Non-Marginal Flags (NM Flags) were created and applied correctly over the period just prior to, during, and just after the times when the Imbalance Settlement Price rose to above the Strike Price. In particular a focus was placed on the periods from 11:00 – 14:30.

This test involved the following data:

- QBOA ranked set results (similar to Report 50);
- From imbalance pricing savecase[4], internal QBOA calculations from save case prior to ranked set;

[4] The Real Time Imbalance Pricing and Real Time Dispatch software runs each five minutes. Each run creates a "savecase" file which contains the inputs and outputs of each run. These files can be restored in offline study mode to allow detailed analysis of each run.

- RTD savecase Scheduled Output, Higher and Lower Operating Limits, Non-Marginal Flagging reasons, Non-Energy Flagging reasons, Reserve provision;
- Validated Technical Offer Data;
- Real Time Availability and Minimum Stable Generation declarations;
- Instruction profiling Dispatch Quantity.

As part of this analysis, information from the RTD run savecases were needed for each five minute scheduling period over the time in question. When finding the data from these sources, it was found that there were no specific RTD runs for a number of scheduling periods:

- 11:00 and 11:05, results from 10:55 run used;
- 11:15 and 11:20, results from 11:10 run used;
- 11:30, results from 11:25 run used;
- 12:45, 12:50, 12:55, and 13:00, results from 12:40 run used;
- 14:00, results from 13:55 run used.

The reason for this is still being investigated. It can be difficult to determine a reason since no data for the run is saved due to it not being completed, but for example this can sometimes occur if the amount of time needed to complete the optimisation exceeds a timeout limit. Since RTD runs cover an optimisation horizon of one hour, all of these scheduling periods did have data available for them from a previous run. However, since this data was based on the latest data possible, it may not be as reflective of system conditions and other information as if the latest run possible for the period had completed. Also, the initial condition for the first scheduling period in an RTD run is the current physical output of the unit, meaning the Scheduled Output of the unit in that period will reflect that, while the initial condition for the subsequent scheduling periods in the optimisation horizon for the same run is the scheduled generation from the previous scheduling period. Therefore the scheduled generation for the periods where previous runs were used will be impacted by different initial conditions.

An example of this can be seen in the first graph in section 8.6 below. For unit GU_500283, in the periods 12:00-12:30, despite the Scheduled Output appearing as the same constant value, the unit is continuously being Non-Marginal Flagged. This is because this Scheduled Output position is at the ramp limit in relation to the initial condition of the actual output level of the unit. Then in the period 12:45 – 13:00, the unit has a higher Scheduled Output than in these previous periods but is not Non-Marginal Flagged. This is because more up-to-date RTD results were not available for these periods other than the 12:40 run of RTD. Therefore for 12:45 the Scheduled Output is not against a ramp limit versus the initial condition of the Scheduled Output for 12:40, for 12:50 the Scheduled Output is not against a ramp limit versus the initial condition of the Scheduled Output for 12:45, etc.

None of the imbalance prices that exceeded the strike price relate to pricing periods for which no RTD savecase exists.

8.2 DEFECTS ACTIVE OVER THE TIME IN QUESTION

The following graph which summarises the positive and negative 5 minute QBOAs and their prices was used to identify if, at a high level, it appears that any of the known defects manifested during the periods in question. From the below, it appears that only the known defect, where the price used for a unit switches for some five minute periods from Simple Bid Offer Data to Complex Bid Offer Data, is active. This can be seen visually on the graph by sudden changes for one or a small number of periods in the colours, in particular from red to green or yellow and then back to red.

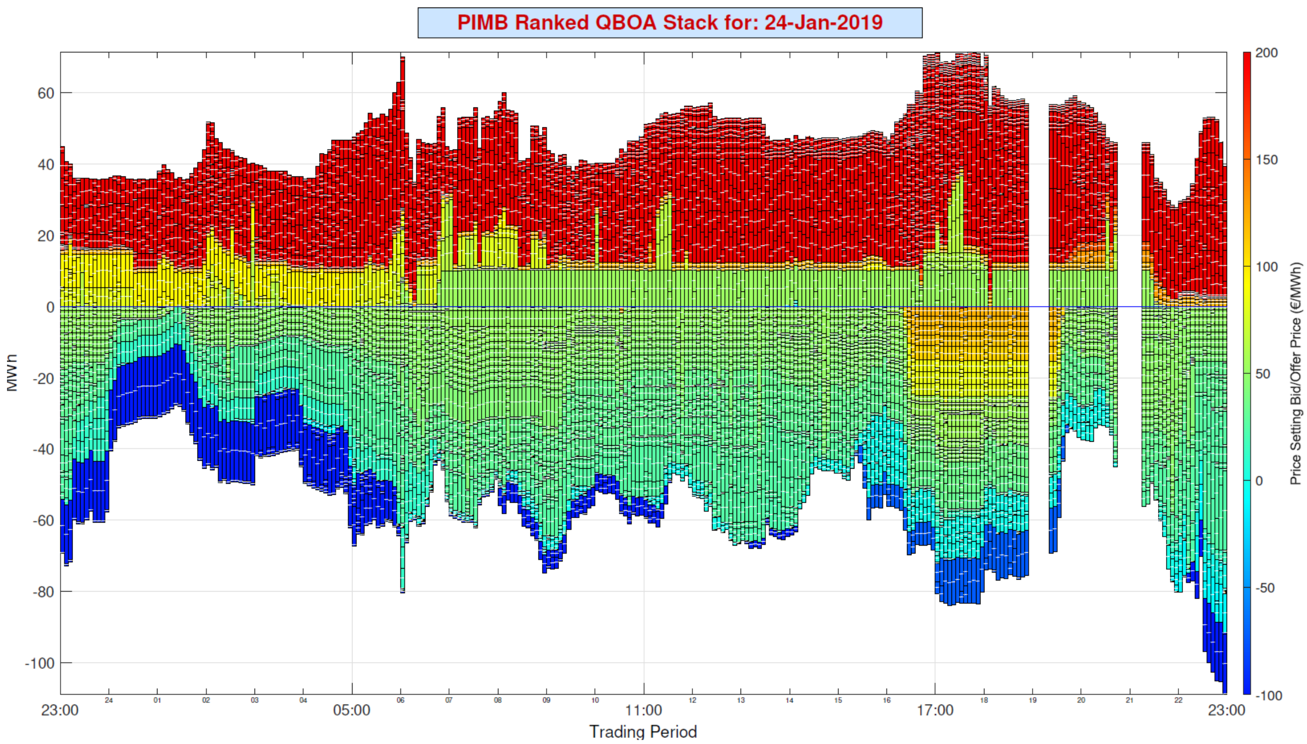


Figure 11 - QBOA Stack for 24th January

The graph above represents the QBOA stack. The left axis shows the volume in MWh with values above the zero line being inc QBOAs and values below the line being dec QBOAs. The colour coding of each QBOA is a guide to the price range of each action which is set out in the legend to the right of the graph.

The following were the times where the five minute Imbalance Price rose above the Strike Price:

- 24/01/2019 11:35:00 GMT
- 24/01/2019 11:40:00 GMT
- 24/01/2019 11:45:00 GMT
- 24/01/2019 11:50:00 GMT
- 24/01/2019 12:35:00 GMT
- 24/01/2019 13:10:00 GMT
- 24/01/2019 13:15:00 GMT
- 24/01/2019 13:20:00 GMT

- 24/01/2019 13:25:00 GMT
- 24/01/2019 13:30:00 GMT
- 24/01/2019 13:35:00 GMT

Each individual case of an apparent manifestation of this defect was identified, and was analysed to determine if it would have had an impact on the final Imbalance Price. In summary, approximately 11 periods were identified, and only two of the periods identified are thought to possibly have an impact on the final Imbalance Price. As the periods do not coincide with a higher priced period, and the difference in the prices versus what would have occurred in the absence of the defect is estimated to be small, this is not likely to have a very noticeable change to the outcomes in the periods in question.

The following gives more detail on the identified periods and cases where the defect appears to be active in a positive QBOA direction:

- 11:05 GU_500820 changed from Simple of 470.7 to Complex of 139.47, GU_500821 changed from Simple of 470.7 to Complex of 139.47 (PMEA in positive NIV situation was lower than these prices, and the prices of units included in NIV and PAR Tagging were lower than both of these prices, so could not have influenced the price);
- 11:15 GU_500822 changed from Simple of 226.87 to Complex of 66.28, GU_500823 changed from Simple of 226.87 to Complex of 66.28 (all actions flagged so couldn't have set PMEA, and in opposite direction to the negative NIV so could not have been included in NIV or PAR Tag, so could not have influenced the price);
- 11:20 GU_500822 changed from Simple of 226.87 to Complex of 66.28, GU_500823 changed from Simple of 226.87 to Complex of 66.28, GU_500041 changed from Simple of 490.78 to Complex of 78.68 (all actions flagged so couldn't have set PMEA, and in opposite direction to the negative NIV so could not have been included in NIV or PAR Tag, so could not have influenced the price);
- 11:25 GU_500822 changed from Simple of 226.87 to Complex of 66.28, GU_500823 changed from Simple of 226.87 to Complex of 66.28 (all actions flagged so couldn't have set PMEA, and in opposite direction to the negative NIV so could not have been included in NIV or PAR Tag, so could not have influenced the price);
- 11:30 GU_500822 changed from Simple of 226.87 to Complex of 66.28, GU_500823 changed from Simple of 226.87 to Complex of 66.28 (all actions flagged so couldn't have set PMEA, and the prices of units included in NIV and PAR Tagging were lower than both of these prices, so could not have influenced the price)
- 11:50 GU_500041 changed from Simple of 490.78 to Complex of 78.68 (the PMEA was set by a unit with a price higher than both of these in this positive NIV situation so couldn't have set PMEA, and while the change in prices did change the relative position of the BOAs in the ranked set for this particular unit, it did not change the relative position of the actions included in the NIV and PAR tags (one with a higher set of prices than both of these, one with a lower set of prices than both of these), this unit was Imbalance Price Flagged and the other unit which was included in the NIV and PAR tag which had a lower price than it was not Imbalance Price Flagged, meaning that this non-Imbalance Price Flagged action needed to be partially tagged in

order to reach the NIV rather than a situation where previously flagged actions become untagged, meaning the actions from this particular unit could not have been untagged to influence the price through the NIV and PAR, therefore it could not have influenced the price).

The following gives more detail on the identified periods and cases where the defect appears to be active in a negative QBOA direction. These are only thought of as possible instances since the price differences are much lower, and they were not all investigated in as much detail as the positive QBOA direction instances because there were more broad explanations for why they could not have impacted the final Imbalance Price:

- 11:40 QBOA is opposite sign of NIV so no effect on overall price because it would not have set PMEA as there were unflagged actions in the direction of the NIV, and it would not be included after NIV Tagging;
- 11:45 QBOA is opposite sign of NIV so no effect on overall price because it would not have set PMEA as there were unflagged actions in the direction of the NIV, and it would not be included after NIV Tagging;
- 12:30 GU_400530 changed from 33.1, 28.5 and 25.5 to 53.4, 49 and 44.4, QBOA is same sign as NIV but could not have set PMEA due to being flagged, PMEA was set lower than all of the Complex Prices therefore they would not have been replacement priced, but higher than two of the Simple Prices therefore if Simple COD had been correctly used some would have been replacement priced. Two of the prices were included in the NIV and PAR Tags based on their Complex COD values, had the correct Simple COD been used they would not have been included in these tags. The actions that would have been correctly included instead based on the next in the merit have similar levels of prices. Therefore this defect does have an impact on the final price, but not a very large one (e.g. of order of 1-5€/MWh);
- 12:45 GU_400530 changed from 33.1, 28.5 and 25.5 to 53.4, 49 and 44.4, QBOA is same sign as NIV but could not have set PMEA due to flagging (all units were flagged), PMEA was set lower than all of the Complex and Simple Prices therefore none would have been replacement priced. Two of the prices were included in the NIV and PAR Tags based on their Complex COD values, had the correct Simple COD been used they would not have been included in these tags. The actions that would have been correctly included instead based on the next in the merit have similar levels of prices. Therefore this defect does have an impact on the final price, but not a very large one (e.g. of order of 1-5€/MWh);
- 13:20 QBOA is same sign as NIV but could not have set PMEA due to being flagged, and since PMEA was higher than all bid prices they would have been replacement priced to PMEA anyway, so no effect on overall price.

8.3 NON-MARGINAL FLAGGING

A check was carried out to determine if all RTD determined flags were correctly applied to BOAs in the ranked set, and it was found that there were no examples of RTD flagged units without a NM Flag value of zero associated with their BOA; i.e., the flags seem to be applied correctly.

In addition to NM Flagging (as a result of the RTD tests for whether or not a unit is at its Higher Operating Limit (HOL), Lower Operating Limits (LOL) or ramping limits), all BOAs for a unit except for the final one are also non-marginal flagged. This is because only the last action taken on a unit can be the marginal one, reflecting the output range and Price Quantity Pair Band within which the next MW up or down on a unit could come from based on the level to which the unit is dispatched. A check was carried out to determine if there were any cases where units had all of their QBOAs NM Flagged despite not being NM Flagged through RTD. There were examples of instances where, despite the unit not being non-marginal flagged due to RTD tests for HOL, LOL or Ramping limits, the unit has non-marginal flags set to 0 for all BOAs in the ranked set.

The following are examples of units and periods where this occurred:

Unit ID	Imbalance Pricing Period
GU_400270	24/01/2019 14:20:00 GMT
	24/01/2019 14:25:00 GMT
GU_400272	24/01/2019 13:05:00 GMT
GU_400480	24/01/2019 11:30:00 GMT
	24/01/2019 12:05:00 GMT
	24/01/2019 12:35:00 GMT
	24/01/2019 13:00:00 GMT
	24/01/2019 14:00:00 GMT
GU_400500	24/01/2019 12:50:00 GMT
	24/01/2019 13:45:00 GMT
	24/01/2019 14:05:00 GMT
	24/01/2019 13:50:00 GMT
GU_400530	24/01/2019 11:20:00 GMT
	24/01/2019 14:10:00 GMT
	24/01/2019 14:15:00 GMT
GU_400850	24/01/2019 11:30:00 GMT
	24/01/2019 11:35:00 GMT
	24/01/2019 11:55:00 GMT
GU_500820	24/01/2019 10:55:00 GMT
GU_500821	24/01/2019 10:55:00 GMT

Table 1 = Units non-marginal flagged during high price periods

Upon further investigation, this seems to be because the step of applying these Non-Marginal Flags to all except for the final BOA on the unit is carried out prior to the step of removing BOAs whose quantity is less than the De Minimis Acceptance Threshold from the ranked set. This means that there is actually one additional BOA with a non-zero quantity, which is the last one for the unit in that period, and this is the one assumed to be marginal while the others are non-marginal. However this BOA is removed from the ranked set because its volume is less than 0.17MWh, and therefore it appears as if all the BOAs for the unit in the ranked set are non-marginal flagged.

8.3.1 LOL NM FLAGGING

The following checks were carried out on each unit:

- If RTD said the unit is flagged for Lower Operating Limit (LOL):
    - Checking if in the ranked set the unit had a NM flag of zero for all of its BOAs (checking if flag applied correctly);
    - Checking that their Scheduled Output was less than, or equal to their Minimum Stable Generation (checking if the flag was set correctly).

The rule is that a unit is flagged as being at their Lower Operating Limit if their Scheduled Output is less than or equal to their Minimum Stable Generation (MSG). The reason why the rule is not just an equality one is because, if loading up or deloading, then that output is a unit's LOL in the moment, even if the stated LOL is 0 or MSG. However, it is acknowledged that the description of this rule in the Methodology For Determining System Operator and Non-Marginal Flags[5] is "Generator Units that are operating at their minimum stable generation" rather than "less than or equal to their minimum stable generation". This would not have had an impact on the values of NM flags for units, as the units would have been flagged for being considered ramp constrained while loading or deloading, it is solely the fact that the reason the RTD system states for flagging the unit is LOL rather than ramping in these scenarios.

There were instances where units were dispatched above their registered MSG but were still flagged for NM Flagged for reasons of LOL. However it was found that these units declared in real-time a different MSG to their registered value, and using this declared value in the test logic it appeared that the units were correctly flagged. Based on this logic, all units passed the checks; i.e., it appears that these flags were created correctly.

8.3.2 HOL NM FLAGGING

The following checks were carried out on each unit:

- If RTD said the unit is flagged for Higher Operating Limit (HOL):
    - Checking if, in the ranked set, the unit had a NM flag of zero for all of its BOAs (checking if flag applied correctly);
    - Checking that their Scheduled Output was equal to their RTD HOL (checking if the flag was set correctly).

Based on these checks, all units passed without need to investigate any further for particular treatment in different circumstances.

8.3.3 RAMPING FLAGS

In some instances, units were flagged for ramping over multiple periods in a row despite the Scheduled

[5] The document is available here.

Output being the same in each instance. This occurs due to a difference between the actual dispatch of a unit and the Scheduled Output of a unit from RTD. The initial conditions for an RTD run include the current physical output of the unit. If the RTD schedule determines that the most economic action to take in a five minute period is to ramp from the current output level to a new output level, and in consecutive runs it does this, from just looking at the Scheduled Output of the unit in each of the periods it may look like the unit is at a constant level, but from the results of the scheduling run it is considered ramping from its start point, and therefore can be Non-Marginal Flagged.

During the period of time where the latest RTD was not available (e.g. from 12:45 – 13:00), this impact is not present because, for the 12:40 RTD run, while the initial condition for the 12:40-45 period is the current physical output of the unit, the initial condition for the 12:45-50 run is the Scheduled Output from the 12:40-45 period. Therefore, units that may have been considered ramping, due to their current output start point, in all of those runs (if those runs had been completed), may not be considered ramping in the later periods whose start point is the previous Scheduled Output. Over the 12:45-13:00 timeframe discussed, the units GU_500283 (BGT1) and GU_500284 (BGT2) were not flagged for ramping reasons[6], following an extended period of time where they were flagged for ramping reasons.

Examples visualising this can be found in the graph in section 8.6 below, summarising the output and impact on flags and price for the unit GU_500283 and GU_500284.

Based on this, we conclude that the Non-Marginal Flags based on ramping reasons have been applied correctly.

8.4 NI REPLACEMENT RESERVE DURING UNIT TRIP

Analysis was carried out into the impact of the trip of unit GU_500041 (CGT8) had on the Northern Ireland Replacement Reserve constraint. The declaration of the change in availability to zero was submitted and updated into the market systems at 12:39; however, the effective time from which it was to apply was 12:25. Therefore, there would have been a number of RTD runs which could not have taken this information into account, including the run for the scheduling period 12:40, because RTD is run a number of minutes in advance of the first period in the optimisation horizon. The RTD runs for the period between 12:45 and 13:00 did not complete; therefore, the influence of this could not have been present in the flagging results during that period. Only from 13:05 onwards would this updated declaration have been able to be reflected in the scheduling systems and therefore flagging results. At 14:07 (according to ex-post availability effective time) the unit was available again.

Since this unit contributes to the Replacement Reserve constraint in NI, analysis was carried out to investigate the provision versus requirement of this constraint, since it contributes to flags for pricing. The following graph summarises the relevant data:

[6] During this time, the units were flagged for HOL reasons or not flagged at all

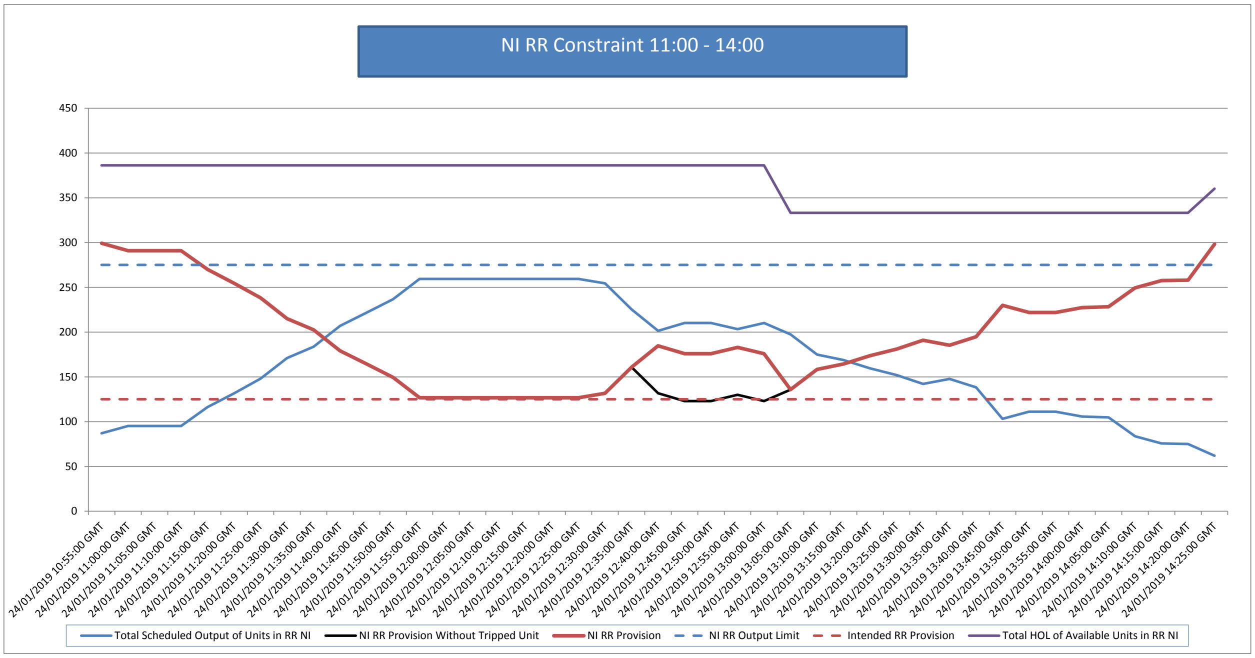


Figure 12 - Northern Ireland Replacement Reserve Constraint across affected periods

With the input data available to the RTD application, the runs which were completed and therefore available to input to flagging and pricing processes, the 275MW max MW constraint is satisfied and not binding in any period[7]. The intended Replacement Reserve holdings of 125MW that the constraint is modelled to provide is also satisfied: despite the solid red line showing the provision appearing to be at the same level as the dashed red line requirement in some periods, it is actually above the value of 125MW in every period. Had the information from the tripped unit come into the system from the time the update was issued (rather than the effective time), and if the RTD runs for the periods which were missing were completed with that updated information, then for all periods the 275MW max MW constraint would have been satisfied, but the intended 125MW RR holdings may not have been reflected in periods 12:45, 12:50, and 13:00 (as shown by the black line on the graph). This is estimated based simply on taking away the max generation of the unit away from the Replacement Reserve provision calculated on all of the units over the period of time where the RTD runs were not completed. However, it is not possible to definitively say what the amount of RR held would actually have been had the RTD runs over that period of time completed. If they had been completed, the optimisation could have resulted in a different outcome taking account of the different situation which does, or does not, satisfy all aspects. This is shown on the black line in the graph, versus the red line which was calculated based on the RTD outputs of the 12:40 run.

Also, not shown on the graph, had the information been received from the tripped generator, GU_500041 (CGT8), about when their availability went to zero at the time that it occurred, and if the RTD runs for the periods which were missing were carried out with that updated information, then for all periods the 275MW max MW constraint would still have been satisfied, but the intended 125MW RR

[7] The combined MW output of OCGTs and AGUs must be less than 275 MW (out of a total of 400 MW) in Northern Ireland at all times. 125 MW is required for replacement reserve.

holdings may not have been reflected in periods 12:30 and 12:35 depending on the timing of the re-declaration versus the time of the RTD run. It should be noted that in real-time operations it is not possible that a tripping generator could update their availability at the exact time of the trip event and that the view noted here is simply if such information had been available earlier, it is unlikely to have impacted on the application of flags and tags.

From the time that the RTD runs continued, and the lack of availability of the tripped unit was incorporated into reducing the HOL on that unit, both the 275MW Max MW constraint, and the intended 125MW Replacement Reserve holdings, were satisfied.

Therefore, because the rules state that flags are based on the indicative operations schedule constraints that are present and the requirement to maintain output of the relevant subset of units to a level below 275MW was shown to be consistently met, the outcomes for flagging for the Replacement Reserve constraint were correct.

8.5 SYSTEM OPERATOR FLAGGING

In checking SO-Flags, a test was carried out to compare instances of a unit being flagged in RTD for a constraint, and the SO Flag value in the ranked set being zero. Any instances where a unit had an SO Flag value of zero but was not flagged in RTD, or where they were flagged in RTD but had an SO Flag value of one, would indicate an incorrect application of the flagging results. From this test it was found that all flags in RTD were correctly applied through SO Flag values to BOAs in the ranked set;

The following flags appeared in the RTD savecases (and may also appear in the Supporting Information reports published from the market system) during the time in question:

- S_MWR_ROI (binding in every period analysed, flagging all IE units with two exceptions discussed later, and some NI units based on these units being Largest Single Infeed (LSI) or up against Primary Operating Reserve Limits);
- S_PRM_TOT (not actually binding, appearing due to FPN test, SO Flag value of 1);
- S_PRM_ROI (between two and six units in the periods between 13:05 and 13:40);
- S_PRM_NI (three units in periods 12:45 and 13:00);
- S_NBMAX_STHLD2 (not actually binding, appearing as a result of a redundant test, SO Flag value 1);
- S_NBMAX_STHLD3 (not actually binding, appearing as a result of a redundant test, SO Flag value 1);
- S_NBMAX_Dub_NB (not actually binding, appearing as a result of a redundant test, SO Flag value 1).

There are a number of constraints which appear in the results despite not being described in the Operational Constraints Update document (this includes S_NBMAX_STHLD2, S_NBMAX_STHLD3, S_NBMAX_Dub_NB). When a constraint is set up to be applied to the schedule, it can be created as a maximum constraint (the values must be less than or equal to something), minimum constraint (the values must be greater than or equal to something), or both (the values must be between one value and another). When a constraint is set up in scheduling, it is also automatically set up in the pricing application as a test to be carried out for creating SO Flags. However, in the pricing application, it is set up so that both a maximum and a minimum version of the constraint are created, regardless of the actual type of constraint applied in the scheduling process. This allows the pricing application to test for any means by which the constraint can be applied in RTD. The pricing application contains the ability to configure this setup where the relevant versions of the constraint can be set to result in an SO Flag value of 0 where that is the version of the constraint applied to the schedule. Where the version of the constraint in the pricing application is not applied in RTD then it is configured to always result in an SO Flag value of 1 rendering this as a redundant test.

Each constraint set up for pricing, regardless of whether they are configured in such a way that they cannot result in the unit being SO Flagged because the constraint is not applied to the schedule, has a test carried out for it with the values it has available from the configuration of the constraint in the pricing application. For example, a constraint which is configured as a minimum constraint in RTD will state what that minimum value is, and the minimum version of the test in the pricing application will use that correctly. However, as noted above, there is also a maximum version of the constraint test in the pricing application which will use that same information to test if the constraint binds were it based on a maximum constraint. The configuration of constraint tests in pricing only determine if the results for those tests create a flag value of 0 or not. As such, constraints that are subject to redundant tests still appear as something that the unit is bound by, but just with an SO Flag value of 1.

There is also logic in the systems which test whether the constraint would have been binding or breached based on the FPNs of the unit. Again, it is configurable as to whether or not this test would result in a flag value of 0 or not, and it is currently configured to always have an SO Flag value of 1 if binding solely for reasons of the FPN test. This can result in constraints showing as binding, which do correspond to ones described in the Operational Constraints Update document (this includes S_PRM_TOT), that have an SO Flag value of 1 associated with it.

Overall, it is advised that if a constraint is showing in the report and the value of the SO Flag associated with the constraint is equal to 1, then this information can be ignored as it is either one of the constraints configured not to apply, or it is a constraint binding only due to the FPN test which is not currently being actively applied.

The following graph shows the NI Primary Operating Reserve provision versus requirement over the period of time in question:

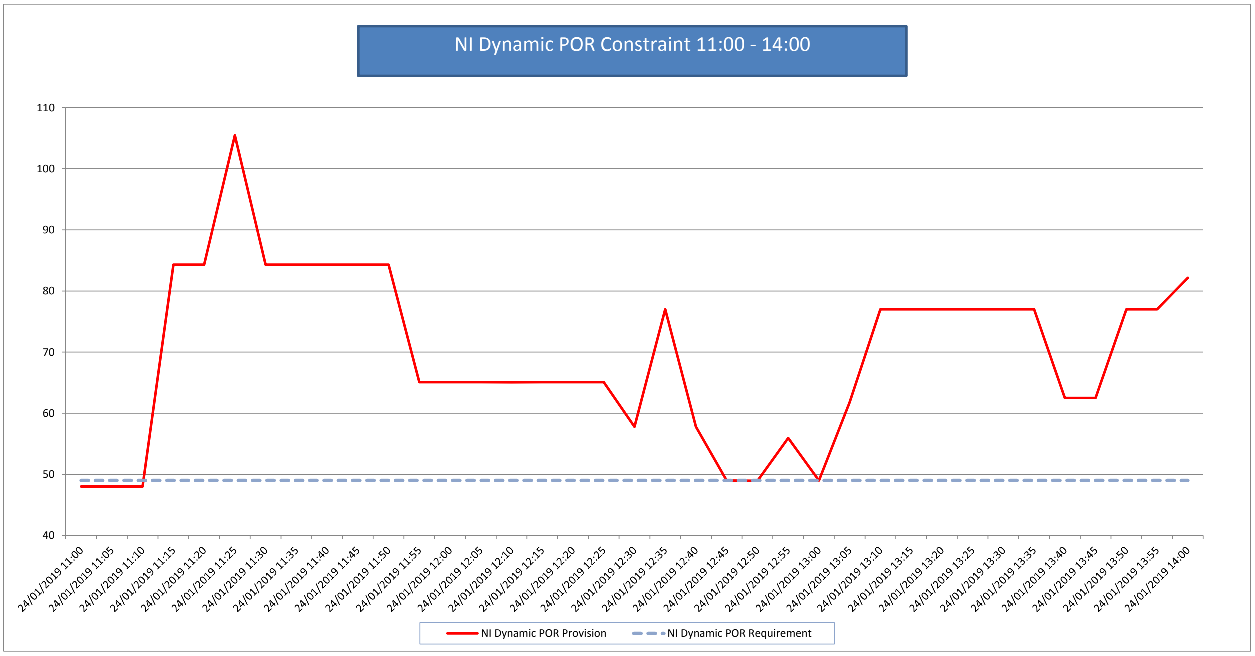


Figure 13 - Northern Ireland POR Constraint across affected periods

While on this graph it appears that at 12:50 the provision is equal to the requirement, in fact it is slightly less than the requirement, as shown by the following graph:

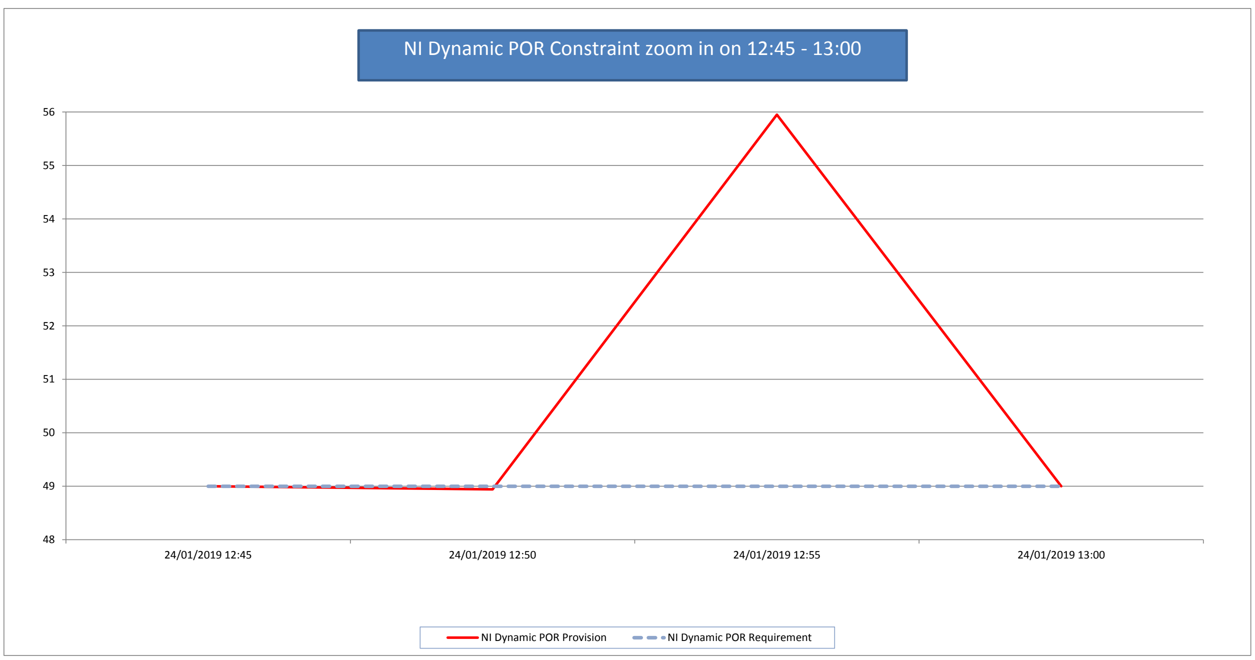


Figure 14 - Northern Ireland POR Constraint between 12:45 and 13:00

The following graph shows ROI Primary Operating Reserve provisions versus requirement over the time in question:

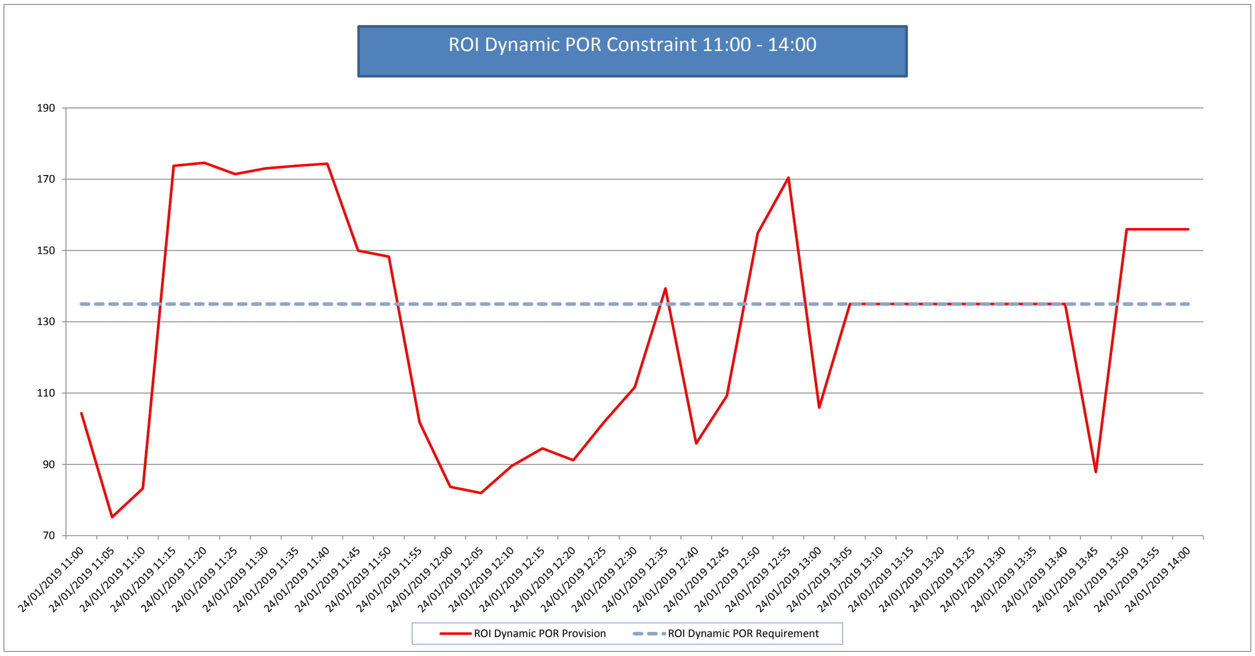


Figure 15 - ROI POR Constraint across affected periods

In the system implementation of the POR constraints (and of the majority of other constraints with different exact tests considered), there are two tests carried out in sequence to determine if a unit is bound by the constraint:

- Test if the constraint itself is binding based on the schedule information;
- Test if the unit contributing to a bound constraint is at a Scheduled Output level which means it is also bound by the constraint.

For the first constraint-based test for the POR constraint, in the pricing application the constraint is considered binding if the shadow price for the constraint is non-zero, and if the provision for the constraint is exactly equal to the requirement.

This is aligned with the description in the Methodology For Determining System Operator and Non-Marginal Flags, which describes the constraint-based test being binding if the provision is equal to the requirement, in section 2.1.1 as follows:

- "For each system service, for all-island requirements and for minimum requirements for each jurisdiction, if the total system service **provision** from all applicable Generator Units (and other sources such as interruptible load) is **equal** to the System Service **requirement**, the constraint is considered **binding** and the following tests are carried out for each Generator Unit that contributes to the constraint."

Part of the theory of why a breached reserve constraint should not result in units being flagged is that since the schedule is determined on the basis that, when the reserve constraint is breached, the units used to breach the constraint are actively being used for energy balancing through the activation of reserves, and therefore these units should not be flagged.

Thinking about how this manifests itself more implicitly within RTD, reserve constraints are modelled as a minimum requirement of reserve to be provided, where the amount provided can be less than the requirement (i.e., the constraint is breached) at the expense of the penalty cost associated the constraint in the optimisation. The penalty cost increases as the amount by which the constraint is breached increases (i.e., as the difference between the provision and the requirement increases). Once the penalty cost starts to be incurred, the marginal effect of the constraint on the output of units contributing to the constraint is reduced to the point where it is not the requirement that is most influencing the Scheduled Output of the unit. The marginal difference between going from exactly meeting the constraint requirements, at a cost of zero, to even slightly breaching the constraint requirements, and starting to incur a penalty cost in the optimisation, is large. Therefore, when possible the optimisation will very actively work to constrain the Scheduled Output of units to such levels as would not breach the constraint and incur that cost.

However, once the constraint has been breached and the penalty cost starts to be incurred, the marginal difference between the cost of breaching the constraint with one Scheduled Output level and the higher cost of further breaching the constraint with a marginally higher Scheduled Output level is small. The need to change the Scheduled Outputs of the relevant units to meet the overarching energy balance requirement is so much more binding on these units that the optimisation is willing to breach the reserve constraint at high cost; therefore, the primary requirement driving the Scheduled Output of the unit is the energy balancing requirement, not the non-energy reserve requirement. Therefore, the optimisation is not as actively constraining the Scheduled Output of units due to the constraint, and the units are not flagged as having their Scheduled Output constrained for non-energy reasons.

For the NI constraint, in periods 11:00 – 11:15, and 12:50, reserve provision was less than reserve requirement, while periods 12:45 and 13:00 had reserve provision exactly equal to reserve requirement. For the latter two periods, three units were showing as having an SO Flag = 0 for this constraint, and for the other periods, no units have an SO Flag = 0 for this constraint. Therefore, this logic is working correctly. For the ROI constraint, only in the periods from 13:05 to 13:40 was the requirement met exactly through provision, and it is only in these periods where between two and six units were flagged for this constraint. Therefore, this logic is working correctly for this constraint.

There were 5 instances found between two ROI units where they did not have an SO Flag value of zero during this period of time, despite the MWR constraint being binding on all other ROI units in those periods. The units were not in the flagging results in the RTD savecase, and therefore were not in the Imbalance Pricing run to be applied to the unit.

For two periods related to GU_400930, this is due to the aspect of the MWR constraint where the first part of the “Min” formula, concerning POR in jurisdiction A, was binding. In these situations, the rule only flags out those units in the ROI jurisdiction that aren’t scheduled on the part of their POR capability curve where an increase in output results in an equal decrease in their reserve provision. Analysis of whether any units in Northern Ireland were flagged for the MWR constraint was carried out for the relevant periods to determine if this part of the formula was binding, This is because, according to the constraint formula, units in jurisdiction B should only be flagged if the second part of the Min function is the one which is binding, while if the first part of the Min function is the one which is binding, only those units in Jurisdiction A which are not on the part of their POR capability curve with a slope of -1 should be flagged. After carrying out this check, no unit in Northern Ireland was found to be flagged in the non-energy flagging results from the RTD savecases for those periods.

Based on the fact that the Largest Single Infeed in Northern Ireland was not flagged out in this period, the version of the MWR constraint which is based on the POR in jurisdiction A (Ireland in this case), rather than the version based on the flow itself and 25% of POR in jurisdiction B (Northern Ireland in this case), is binding. It is not possible to publish the capability curves of units to show definitively where the Scheduled Output of the unit is against its capability due to commercial sensitivity associated with this data. However, having internally reviewed that data, it can be confirmed that the flagging results for this unit are correct.

For three periods related to GU_402030, their HOL was zero in the RTD runs during those periods. These were the only instances of HOL of 0 for an ROI unit over the period in question. The Methodology For Determining System Operator and Non-Marginal Flags describes that units are flagged based on their contribution to a constraint, and therefore a unit which is not contributing to a constraint should not be flagged due to that constraint. When a unit declares itself unavailable and this is reflected in the RTD run, a result of this is that they cannot contribute to the MWR constraint, and therefore they are not flagged for this constraint. In this particular case, the unit declared their availability to zero for a period of time following a trip, which was reflected both in the availability used for the pricing process, removing the QBOA quantity there (this happens when a unit is dispatched to their availability which is below their Final Physical Notification resulting in a QBOA value of 0MWh), and changing the unit’s HOL to zero in RTD.

Because the unit’s QBOA is removed in most of those periods, they are not included in the Ranked Set as part of the pricing process in those periods, and so the setting of an SO Flag would not have any impact on pricing for those periods. The unit had a non-zero QBOA in the periods investigated for their non-zero MWR flag, despite their HOL being zero in those periods, because the RTD process is run in advance of real-time and the pricing process is run after real-time. Due to the time the unit updated to a non-zero availability declaration, this data was available in time for pricing but not for scheduling. This effect was larger because the time the updated non-zero availability declaration was sent was over ten minutes after the time the increase in availability was meant to take effect. This meant that more RTD runs, happening every five minutes ex-ante, would not have this updated availability information than if the send time was closer to the effective time. Therefore, based on the information available to the RTD and pricing processes at the times they were run, not applying the MWR flag in these periods was the correct outcome.

8.6 SUMMARY GRAPHS OF HIGHEST PRICED UNITS

The following graphs summarise the information relevant to determining whether the flags on QBOAs which affected the ability for units to influence the imbalance price were correctly set for a number of the key units, and visualises the effect the change in this input information has on the 5 minute

Imbalance Price. The red and green dashed lines show the unit's Higher Operating Limit and Registered Minimum Stable Generation respectively. The dark blue line shows the unit's Scheduled Output of the unit from the relevant RTD run the results from which were used for flagging in the pricing process. The light blue line shows the total Bid Offer Acceptance Quantity used in the pricing process for that unit, converted from MWh energy in a five minute period to MW power, therefore being indicative of the dispatched position of these units considered in real-time. The blue bar shows periods in which the unit was Non-Marginal Flagged, and the orange bar shows periods in which the unit was System Operator Flagged. The relationship between these items of data can be used to indicate if the unit tests for Non-Marginal and System Operator Flagging had the correct results in each period. The purple line shows the five-minute Imbalance Price, so that the correlation between these units being flagged and their impact on the price can be visualised. The axis for the price is on the right of the graph in €/MWh, while the axis for the MW quantities is on the left.

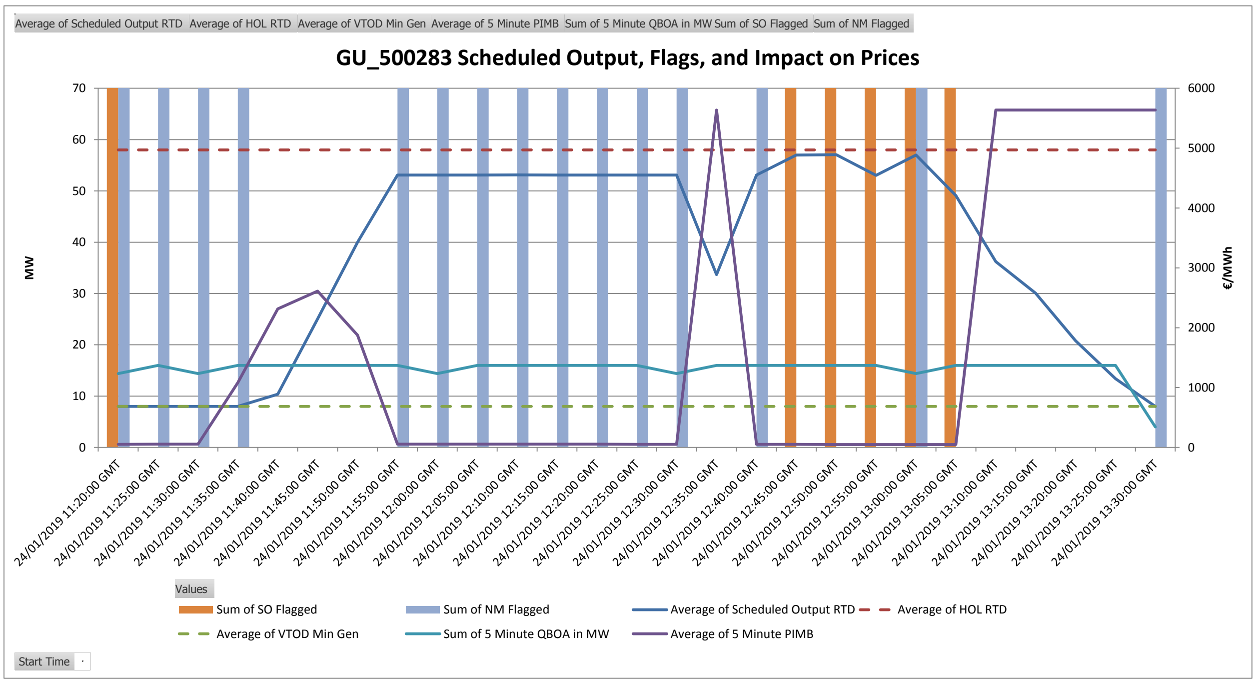


Figure 16 - Scheduled Output and Flags of GU_500283 (did not set the PIMB)

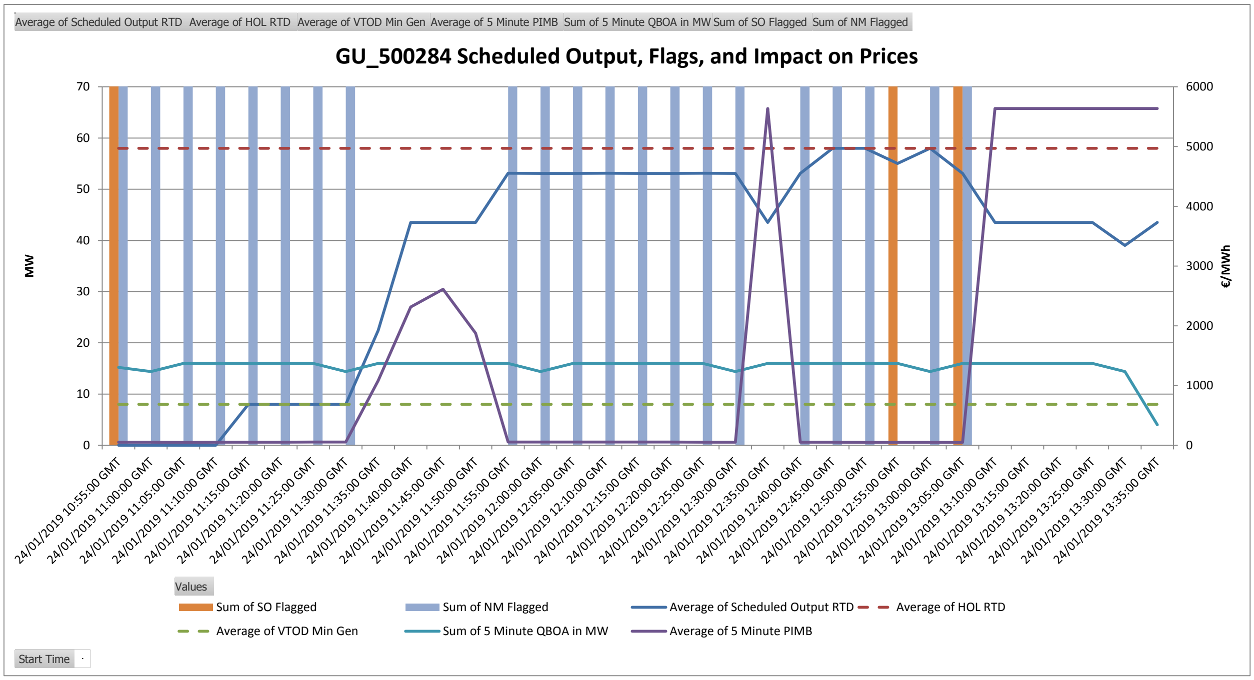


Figure 17 - Scheduled Output and Flags of GU_500284 (set the PIMB)

9 CONCLUSIONS

After a detailed examination of the events leading up to and during January 24th, the following is the sequence of events that has been observed.

Wind forecast, based in the ROI jurisdiction was traded in the ex-ante market which does not take account of inter-area transfer restrictions.

Because the price spread between SEM and BETTA was tighter in the day-ahead market, this resulted in Moyle being utilised to export form the SEM ahead of EWIC.

Plant outages coupled with low wind in Northern Ireland and full exports on the Moyle interconnector meant the system was highly constrained and security standards resulted in the North South tie-line being flagged as binding constraint for much of the periods affected.

When the tie-line constraint is binding, this means that generators (including Demand Side Units) on the exporting side of the tie-line are flagged by the constraint. This is because while the constraint is binding in a South to North direction, as it did on the day, no generator in ROI can solve a marginal increase in system load anywhere in the SEM; they can only solve increases in the ROI area. Only generators in NI can solve a marginal increase is system load anywhere in the SEM.

This resulted in a high priced unit which was synchronised for system reasons and kept at minimum output becoming marginal when the Real Time Dispatch took this as the next cheapest unflagged action in the stack, setting the five minute price at €5,636.62 for a number of Imbalance Pricing Periods.

A detailed review of the flagging of units in the system outputs has shown that flags were applied correctly and none of the known defects in the Imbalance Pricing algorithm impacted in the relevant periods.

10 NEXT STEPS

This report represents a detailed examination of the events leading up to and during January 24th.

It is the intention of EirGrid, SONI and SEMO to provide as much information as is needed to Participants to assist in their understanding the balancing arrangements and details of imbalance pricing. Where Participants have further questions after consuming the details in this report, we would invite them to submit their questions to the market helpdesk (info@sem-o.com) and we will seek to engage further at upcoming events.

While the conclusion is that the imbalance prices were calculated correctly, in accordance with the Trading & Settlement Code, EirGrid, SONI and SEMO recognise that imbalance prices of this scale are unexpected and of serious concern to the industry, particularly given downstream impacts in settlement calculations. EirGrid, SONI and SEMO are committed to further engagement with the Regulatory Authorities and wider industry on the issues that have arisen.

11 APPENDIX 1 – SO GRAPHS OF SYSTEM CONDITIONS

Figure 18 – Moyle Interconnector flows on 24/01/2019

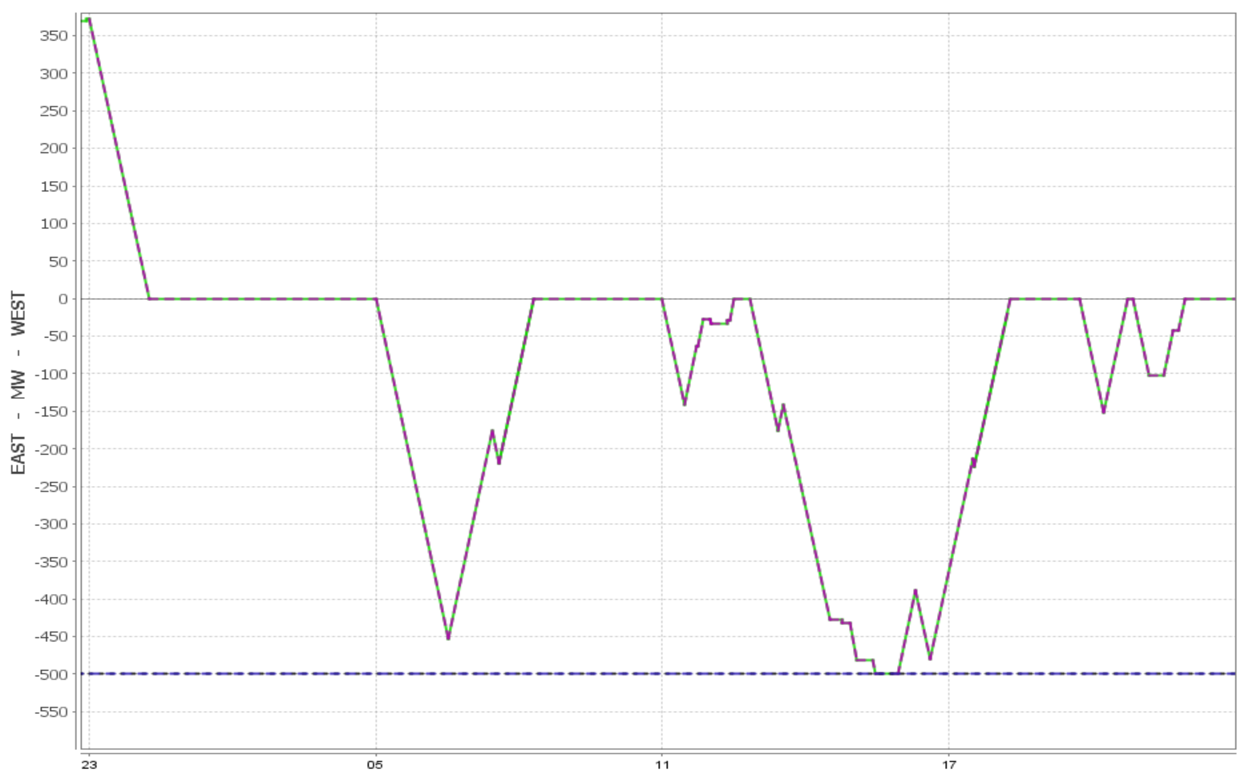


Figure 19 – EWIC flows on 24/01/2019

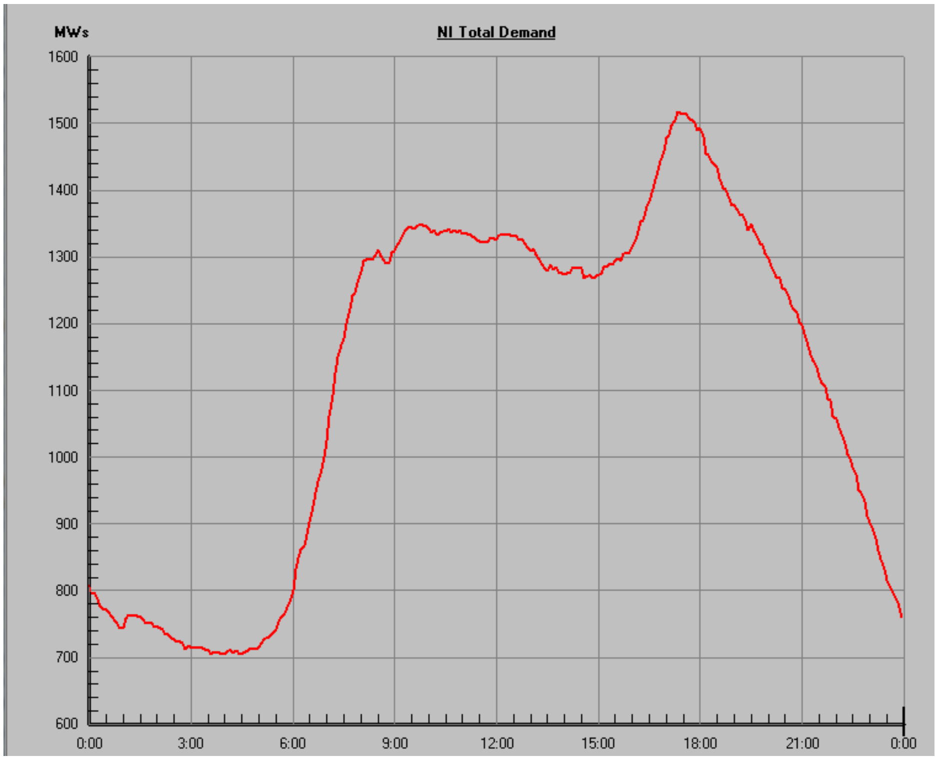


Figure 20 – NI demand for 24/01/2019

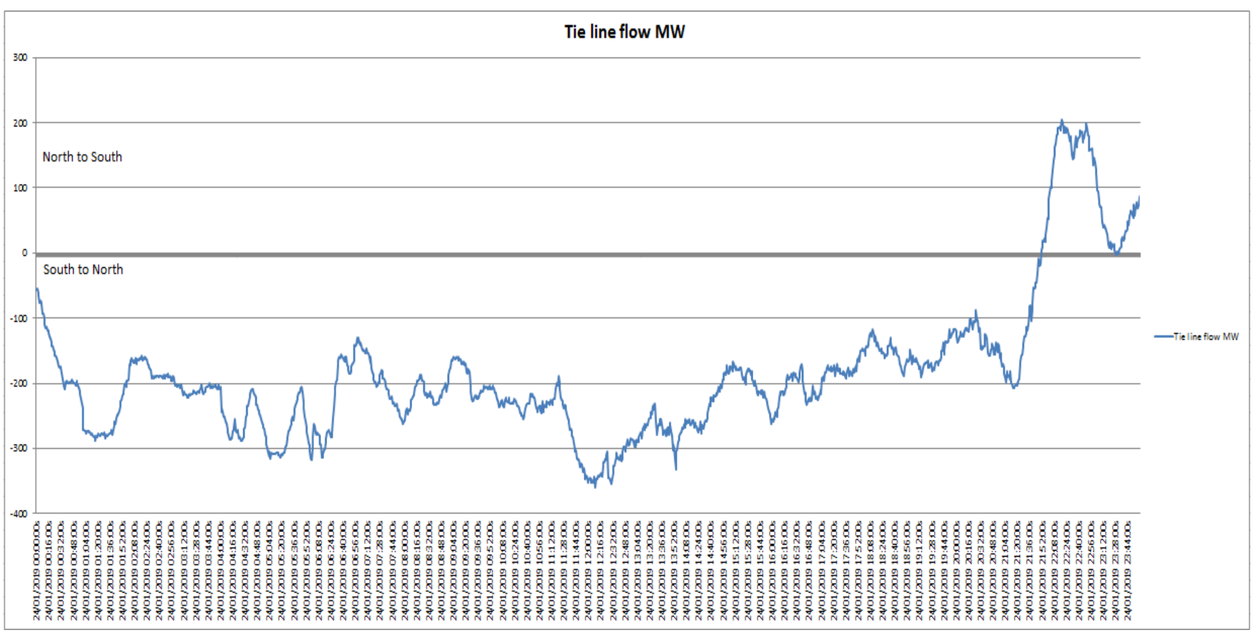


Figure 21 – North South tie line flows for 24/01/2019