ESO Balancing Market Review 2022

The Electricity System Operator (the ESO) has an obligation to co-ordinate and direct the flow of electricity onto and over the National Electricity Transmission System in an efficient, co-ordinated, and economic manner. One of the ways we do this is through the Balancing Market (BM)[1] where we ask generators and storage to increase or reduce electricity output (based on the bids, offers, physical notifications and technical parameters they submit) to continually ensure that supply and demand are balanced and appropriate security margins (e.g., reserve) are in place.

In the latter part of 2021 costs in the Balancing Market rose significantly. While the costs in the Balancing Market typically only make up a relatively small element of the average energy bill, it is very important that these costs are minimised as they are ultimately borne by consumers. At a time when households' budgets are under strain, consumers need to have confidence in all elements of the energy market.

As an example of costs rising, on 24 November 2021, we saw exceptionally high costs in the Balancing Market with over £60m spent[2]. A preliminary review of the data indicated that several large generators changed their notified running (removing physical notifications) at short notice and at the same time increased their offer prices. This resulted in a situation where the ESO Control Room had to accept significant quantities of offers at high prices in order to balance supply and demand and ensure security of supply.

To understand the underlying causes and assess if there were any breaches of market rules, we commissioned a consortium of expert consultants to conduct an external review. We identified the 10 highest cost days in the balancing market over the period September to December 2021 to include within scope of the review (*see Annex 2: Dates and total BM costs).* The report from this external review is attached here. It did not find any specific evidence of parties acting in breach of the Balancing Market rules; however, it does provide some suggestions on potential market changes which may alleviate the risk of further high-cost days.

In the sections below we provide more information on what occurred in the Balancing Market on the 24 November 2021 leading to the high costs on that day. We then set out the scope of the external review and a summary of the key findings before discussing next steps and how we propose to address the issues raised.

An exceptionally high-cost day – 24th November

On 24 November 2021, margins were low but not the lowest we saw over the winter period. There was also high demand in France that day, limiting the ability to use interconnector trades to meet margin requirements. Warming instructions were issued to 4 coal generators by the ESO Control Room signalling to the market that the system was tight and coal generators may be required. Ultimately, only 2 of the 4 generators were in fact deployed in the Balancing Market to meet peak

[1] (See *Annex 1: What is electricity balancing and ESO's role in it?* for a high-level description)
[2] The average daily balancing cost in 2021 was £5.4m and the average across Sept-Dec 2021 was £9.8m

demand (the warming instruction was cancelled on the other 2 generators). No Electricity Market Notices or Capacity Market Notices were issued during the day.

Demand on the day was 43.3GW[3]. Demand forecasts through the day were within operational expectations, improving closer to real-time[4]. Wind generation out turned higher than expected levels[5] for the darkness peak period, but active transmission constraints associated with outages on the network prevented this capacity from being utilised and required acceptance of bids to reduce the output.

Coming into the day (before 6am) several generators had submitted Physical Notifications (PNs) indicating that they intended to run up to lunch-time and then come off-load. Given the technical characteristics of these generators (and specifically their Minimum Zero Time (MZT)) if they came off-load at lunchtime, they would then be unavailable for the darkness peak[6]. Therefore, given projected margins and requirements to manage network constraints, the Control Room needed to delay these generators coming off-load and dispatch them on from lunchtime until after the darkness peak. The costs of this are based on the output level dispatched and the offer price set by the generator.

Then, between 11am and 1pm, 2.6GW of PNs were removed at short notice[7] by generators (i.e., they changed their notified position from running to being off-load for peak periods) and the prices offered by these generators for running (i.e., the cost they quoted for staying, or coming, on-load) increased significantly (see Figure 2). Given the MZT of these generators, if they had come off-load in line with these revised PNs then they would be unavailable over the darkness peak. Therefore, the Control Room, to ensure security of supply and margins over the darkness peak, dispatched these generators on, delaying them coming off-load (desynchronising) until after the darkness peak. The cost of taking these actions is, for each generator, based on the output level dispatched and the offer price set by the generator.

Overall, on 24 November, to manage security of supply, network constraints, and margins over the darkness peak, 2.9GW of offer volume was accepted at a volume weighted average price of £3,253/MWh. Much of this generation had to be run for multiple hours at this price due to the technical characteristics (principally MZTs) that were submitted for the specific generators. The total cost in the Balancing Market of these actions was £53.6m[8].

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[3] Excluding demand STOR/Frequency Response

[4] The 8-hour ahead demand forecast was within less than 1.5% of actual out-turn.

[5] Wind out-turn was 1322MW above forecast levels for the darkness peak cardinal point.

[6] MZT is a technical characteristic of a thermal generator and is there to account for thermal expansion/contraction issues from being taken off-load. One impact of this characteristic is that, for the relevant period post desynchronisation, there is an effective loss of capacity as it cannot run.

[7] A median period of 10 minutes ahead of gate closure was provided for changes in PNs to generate over the darkness peak periods.

[8] Total balancing costs on 24 November were £64.8m, with £53.6m associated with generators run over the darkness peak period. The breakdown of all cost elements is as follows: £55.6m spent on constraints (including replacement energy costs), £6.1m spent on reserve, and £3.10m spent on all other components. *Note these figures do not represent final settlement values. Where a generator provides multiple capabilities (e.g., Constraint replacement energy and operating margin), these are tagged in line with the System management Action Flagging Process (SMAF).*

Understanding generator Physical Notifications (PNs), Offer prices and Minimum Zero Time (MZT)

To assist in understanding the relevance of PNs, offer prices and MZT we have created an example generator and reflected the type of behaviour seen on 24 November in the graph below.

The example generator (BMU: XAMPL-1) has a PN to start generating at 04:30 and ramp up to full generating output of 1,000MW by 06:00. It plans to continue operating at this level until it begins a ramp down process towards de-synchronisation at 13:00 (i.e., coming off-load / a PN of 0 MW). These are the **blue bars**.

Up to this point the generator offers 1,000MW of contribution towards total available generation capacity and margin because that reflects its maximum output. However, whilst the generator is within its Minimum Zero Time (MZT) of 360 minutes (6 hours) following a desynchronisation the contribution towards capacity and margin is 0 MW as the generator is not available to generate. For this generator if it were to come off load (desynchronise) at 1pm it could not come on until 7pm (i.e., after the darkness peak). This is the **black line** on the x-axis from 13:00 to 19:00.

Across the day the Control Room must keep margin at adequate levels to meet potential demand and to maintain appropriate capability to continue supplying customers and consumers even if the largest generator were to unexpectedly fail. Therefore, if the margin were to drop below acceptable levels just for the darkness peak (grey shaded area from 17:00 to 18:00) the Control Room would need to delay the desynchronisation of this generator (XAMPL-1) and dispatch it on from 13:00 until after the darkness peak. In this example from 13:00 until 19:00. These are the **red bars**.

The generator provides a price for any increased output instructed / dispatched through the Balancing Market by the Control Room – the offer price. This can be changed by the generator and, in the example below, it increases from just above £200/MWhr to £1,000/MWhr for the period 13:00 to 19:00. This is the **orange line**.

In this example, the total cost of extending the generator through the balancing mechanism was £2.75m, reflecting a 6-hour extension (irrespective of whether the capacity was only needed over the darkness peak).

MZT is a technical characteristic of a thermal generator and is there to account for thermal expansion / contraction issues from being taken off-load. One impact of this characteristic is that, for the relevant period post desynchronisation, there is an effective loss of capacity as it cannot run.

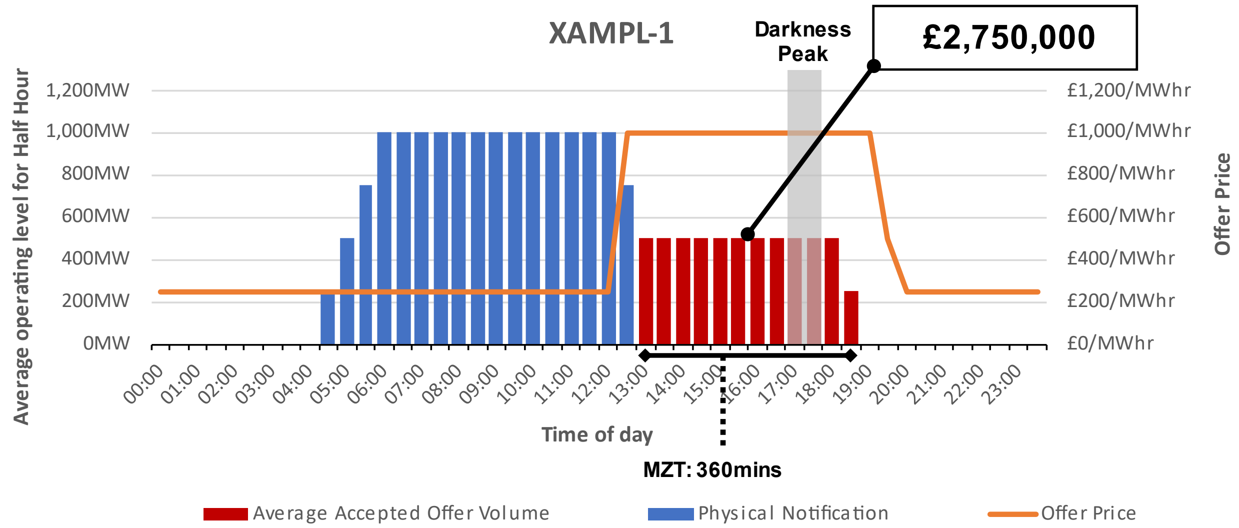

Figure 1: Example Generator 1 (XAMPL-1) is extended through the Balancing Market across darkness peak (at a BM cost of £2.75m) as its MZT period renders the generator unavailable for the darkness peak without offer acceptance through the Balancing Market from 13:00 onwards.

In the graph below, we follow the generators with offers accepted through the Balancing Market across the peak period on 24 November, presenting the view available to ESO control engineers as the day progressed. As outlined above, it is apparent from the 6am view (orange) that multiple generators that were on early in the day were not intending to operate across the darkness peak period and were offering their capacity through the Balancing Market at average offer prices of £1,000/MWhr (£3,900/MWhr coal and £300/MWhr CCGT[9]). Given many of these generators had PNs to generate in the morning pickup, this placed them within their MZT in their original operating profile at the darkness peak, requiring extension through the Balancing Market as the Control Room needed to retain access to this generation capacity to ensure security of supply and margins.

Furthermore by 13:00 (purple) there was a significant drop in the PNs, as multiple CCGT generators withdrew their darkness peak operating profiles and placed themselves within their MZT thus requiring the Control Room to dispatch them on in order to avoid the capacity being unavailable over the darkness peak. This coincided with a significant increase in the average offer prices of these generators[10].

Overall, on the day, the Control Room needed to dispatch on 10 generators through the Balancing Market in order to maintain security of supply and margins across the darkness peak at a cost of £53.6m.

[9] Combined Cycle Gas Turbine (CCGT)

[10] It is also worth noting that some generators were observed further increasing their offer prices even after being accepted through the Balancing Market

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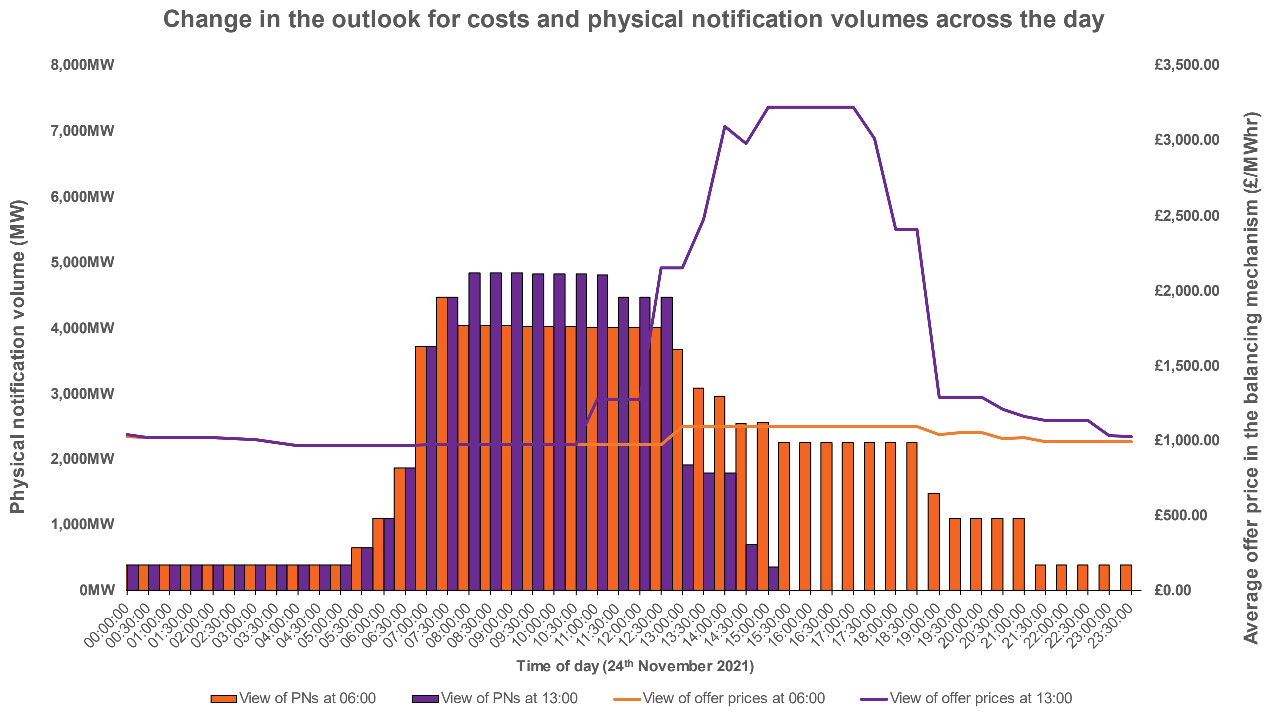


Figure 1: Graph demonstrating the changes in physical notifications and prices across the day, following BMUs which were accepted at peak periods of the day

In Annex 3 we provide the graphs for each of the 10 generators that were dispatched on by the Control Room over the darkness peak showing PNs, dispatched output level, MZT and final Offer prices across the day.

Scope of the External Consultant's Review

As outlined above, we were concerned about the high costs we were seeing in the Balancing Market. In January, we commissioned Frontier Economics, working with Lane Clark & Peacock (LCP) and Cornwall Insight, to conduct an external review of the Balancing Market, specifically considering the following three areas:

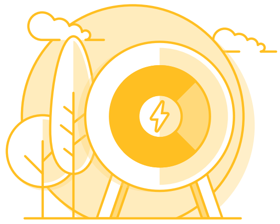
1. **Current Behaviours:** Review of the bids into the balancing market on ten of the highest cost days between September and December 2021. In particular looking at price and technical parameters on these days.
2. **Market rules:** Review of the current market rules to determine whether there is anything inherent in the rules that is perpetuating the behaviours driving the high-cost days.
3. **Stakeholder engagement:** Seek engagement from all market participants to obtain insights on current behaviours as well as any thoughts they may have around the current market rules to feed into the work in areas 1 and 2 above.

The review has been conducted as independent and impartial analysis – including ESO decision making and market participant behaviours to identify the underlying causes for the significant increases in costs in the Balancing Market.

For the 10 highest cost days included in the review, 18% of the total yearly ESO spend on Balancing Market services was concentrated in these 10 days, including a record daily spend of over £60m on 24 November.

Data Driven Review

Independent and Impartial analysis



Targeting the root causes of high costs incurred

Engaging with the whole electricity market

The consultants were provided with datasets showing how the market conditions evolved over these days including the PNs, prices (bids and offers), dynamic parameters, demand forecasts and system operating plans (SOPs). From this data, ESO decision making could be reviewed alongside the drivers behind changes made by market participants, from day-ahead through to real-time. The analysis of the datasets was also supported by interviews with ESO subject matter experts alongside engagement with current and future market participants to provide insight into procedures and market positioning.

A timeline of the various activities is set out below:

January Frontier, LCP and Cornwall insight jointly awarded project	**January** ESO datasets provided, further data provided on request	**February** Analysis conducted into drivers of cost	**March** Initial findings webinar presented capturing market views	**April** Workshop meetings with grouped market participants	**April** Further analysis conducted into areas identified by the market	**May** Additional interviews conducted with subject matter experts	**July 2022** Final findings report published

Note: This review has not considered compliance with either REMIT or competition law. Ofgem is the appropriate authority to consider these areas and has the necessary powers to request information. However, our Market Monitoring department monitors and reports to Ofgem on potential breaches of REMIT (including insider trading and market manipulation) and the Grid Code in balancing services including the Balancing Market and has continued this work alongside supporting the review.

Summary of Conclusions from the Review

What has driven the high costs?

The high costs seen in the Balancing Market during the periods reviewed were driven by system tightness combined with generator bidding (Physical Notifications and Offer prices) behaviour which led to the need to accept offers (i.e., buy electricity) at up to £4,000/MWh across a large amount of coal and gas plant capacity.

The external review noted that since March 2021, some coal plants have been offering all of their capacity into the Balancing Market at around £4,000/MWh. This change in operating characteristics to no longer sell capacity in forward markets and only engage through the Balancing Market contrasts with previous years and was consistently observed across all periods, not just on the high-cost days.

The way in which certain Combined Cycle Gas Turbines (CCGTs) have engaged with the market has also changed as coal warming instructions and tight margins provided an indication that CCGT offers up to £4,000/MWh could be accepted.

When this is combined with a long MZT for large CCGTs, and desynchronisation plans in the afternoon, ESO had to accept offers much earlier in the day to ensure these generators were available for the evening peak. The size and inflexibility of the relevant generators exacerbates the problem as expensive Balancing Market offers had to be accepted over multiple hours to meet the requirements of the darkness peak period. Price changes were typically set at very high levels for the full duration of the extended run required to keep the generators available. This is in contrast to what can be seen in the Day Ahead and Intraday Markets where scarcity pricing was observed, but only for short periods as these markets do not explicitly account for technical inflexibilities.

The report also notes that more accurate forecasting may have led to reduced balancing costs.

Do the rules need changing?

The market rules have exacerbated the costs and given the level of the costs incurred on the high-cost days, it is appropriate to consider potential changes to the rules.

Based on the information that has been available for this review, the consultants' external review found no clear evidence that the relevant market participants' behaviour is inconsistent with the Grid Code (GC) and Balancing and Settlement Code (BSC). Consistency in key dynamic parameters have been observed and, from an economic perspective, there are potential legitimate commercial reasons for the approach taken by the coal and gas generators. However, the current approach of submitting bids and offers may be limiting the ways in which the true technical capability of plants can be expressed, and hence reducing options for the ESO to minimise costs.

Stakeholder views

There is a consistent view from stakeholders that, absent changes, high-cost days are likely to continue. There is however mixed opinion as to whether this is a problem that needs to be solved, and a strong sense across the stakeholder community that any changes need to be fully considered and should not just be reactionary. Stakeholders have provided a broad range of ideas as to what actions could be taken.

Possible changes to the rules

The external consultants were asked to consider any changes that could be made to address the key cost drivers identified in the review. From the analysis the consultants have carried out, they consider the categories of interventions that should be considered are:

A) Shorter term interventions focused on next winter could include:

- a bidding code or licence obligation determining how participants can bid into the market – seeking to manage some of the behaviours we have seen drive up the prices;
- the implementation of price caps;
- further improvements in demand and/or wind forecasting; and
- greater transparency of operational decision making and management of STOR.

B) Longer term interventions could include:

- looking at changes to the Balancing Market offer structure (this work would need to align with other industry workstreams); and
- Broader market interventions, for example, consideration of the capacity market and how any changes could benefit the Balancing Market. These proposals would need to be considered alongside the wider market reform work being led by BEIS and Ofgem.

The report includes an initial assessment of the options and highlights the need for further detailed consideration. For example, in relation to some of the options (e.g. price caps) it will be particularly important to consider their incentive effects and the risk of unintended consequences.

Conclusions

In the latter part of 2021, we saw several very high-cost days in the Balancing Market. While the costs in the Balancing Market typically only make up a relatively small element of the average energy bill, it is very important that these costs are minimised as they are ultimately borne by consumers. At a time when households' budgets are under strain, consumers need to have confidence in all elements of the energy market.

We therefore commissioned an external expert review of the 10 highest cost days in 2021 to assist our understanding of the factors driving the high costs seen in the Balancing Market. The review has not found any clear evidence that market participants' behaviours were inconsistent with the Balancing Market rules, however it does make recommendations around possible changes to improve the Balancing Market.

In our view the high prices suggest that the market is not operating as effectively as it could be, and that change is needed. We have provided our report to both Ofgem and BEIS for their review and consideration of any next steps that they believe may be appropriate.

As we approach Winter 2022/23 the ESO is committed to working hard, both internally and across the industry, to drive down costs in the Balancing Market to the extent that we can. Some of the initiatives we have underway include:

- Improvements to the accuracy of forecasts – the ESO is always seeking to improve the accuracy of forecasts and multiple improvements are underway in line with our business plan proposals.
- Enhanced transparency - we have introduced multiple channels to provide more transparency over the operation of the power system and market, including ESO operational decision making. This includes our weekly transparency forum webinars, our dispatch transparency datasets and wider ESO data portal publications. We are continuing to look at what further transparency may be helpful and/or useful in mitigating high costs in the Balancing Market.
- Regular review of products - we have several products that sit alongside the Balancing Market, such as STOR. We need to keep these products under review to ensure that the operation of these products does not inadvertently have a negative impact on the Balancing Market or other market products.

We are conscious of stakeholder feedback around not making immediate reactionary changes to the Balancing Market rules; nevertheless, we do intend to follow-up on the various possible actions set out in the external review and outlined in the sections above. Some of these are outside our remit to give effect to (e.g., licence changes or bidding codes) and will require us to work closely with Ofgem and government around any such proposals.

Finally, the ESO has a project underway to review the electricity market arrangements and whether they are fit for purpose in the context of the transition to Net Zero – our Net Zero Market Reform programme. The learnings from this review of the Balancing Market will be fed into this programme.

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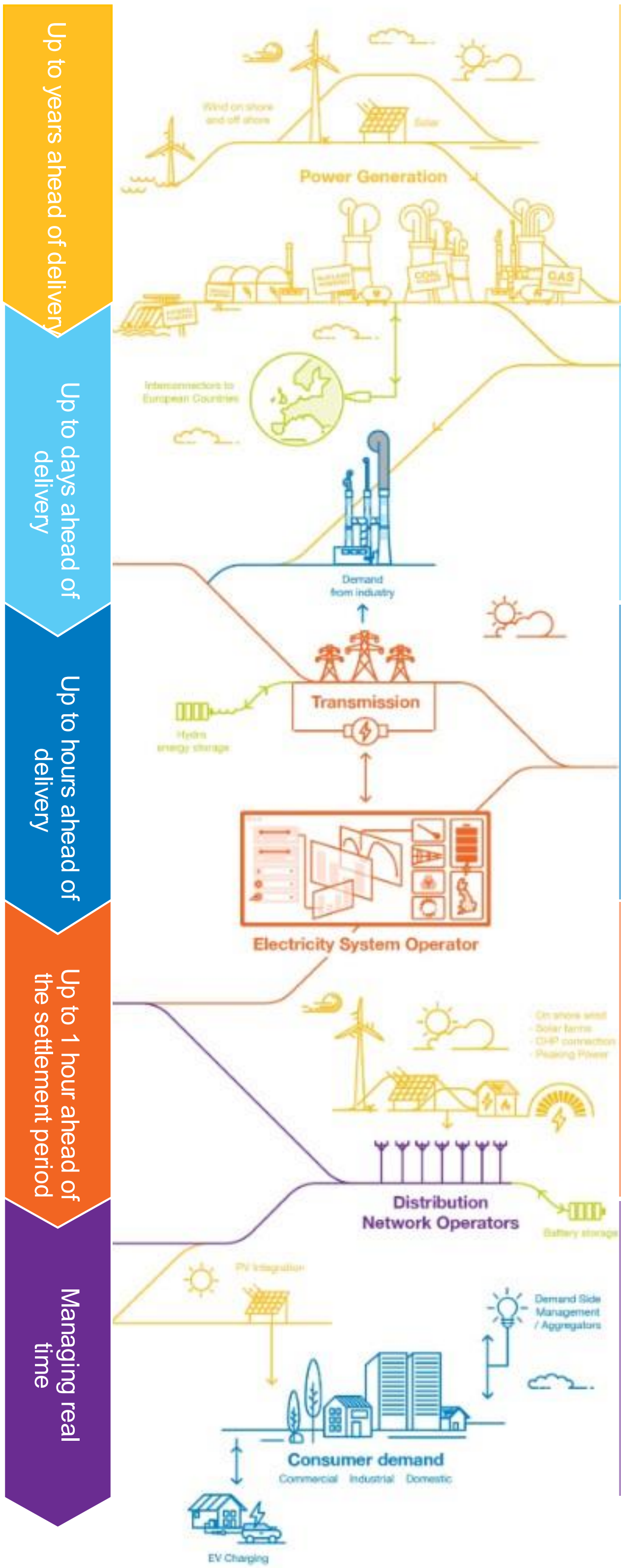
Annex 1: What is electricity balancing and ESO's role in it?



- Capacity market operates to ensure sufficient generation to meet anticipated peak demand
- The Market participants buy and sell electricity, via contractual trades, to hedge their forecast needs and positions
- Ancillary service markets are designed to meet future operability needs
- The ESO may procure long term system services
- Initial transmission network outage planning is conducted

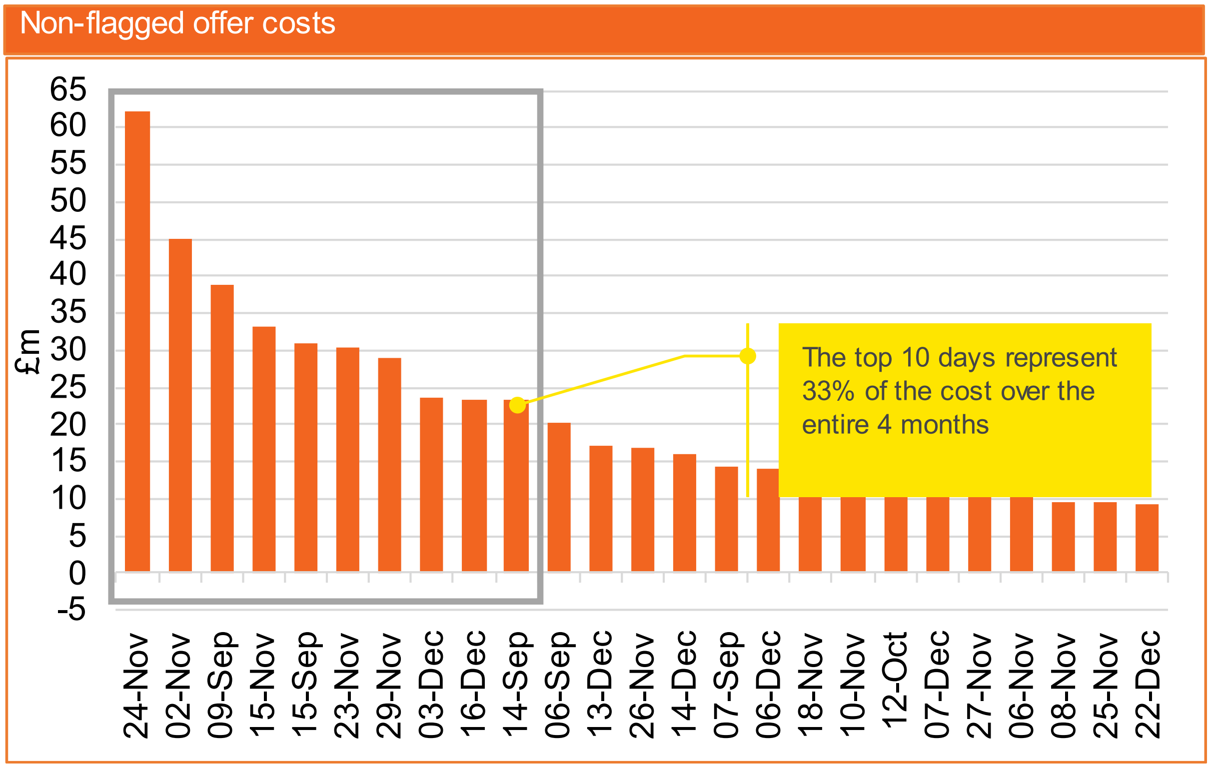
- The ESO may buy Ancillary services, including through "day-ahead" auctions for some products
- All Market Participants continue to refine their positions, with a more accurate knowledge of unit availability and customer demands
- Balancing Market(BM) Participants provide an initial view on their positions and prices to ESO *(known as a Physical Notification or PN)*
- Transmission network outage planning process finalised to ensure system security

- The ESO continually refines forecasts for demand and generation
- Intraday markets runs, enabling continued refinement of the positions of Market Participants
- Units notify ESO of any changes to their positions and prices
- ESO may make trades with generation units or interconnectors, to meet forecast system needs
- Units with a long "Notice to deviate from zero" may be instructed or warmed

- Final PNs are submitted by BM units (BMUs)
- Dynamic data of BM units is updated where a technical change has been made
- Final prices to deviate from the Physical Notifications are submitted *(Bids and Offers)*
- System operating plans are continually refined to take account for changing weather, forecast demand or generation changes

- BMUs are repositioned to account for physical network limitations, or to manage real-time energy imbalance, through accepting bids and offers
- Generator failures are managed through response and reserve products
- Ancillary services are enacted to maintain system safety and security, if required

Annex 2: Dates and total BM costs



This review focuses on the 10 highest cost days through the Balancing Market. Cumulatively they represent a very significant portion of the total balancing costs for the year and therefore the review has been structured to identify root causes and potential solutions. The Frontier report covers 24th November, 2nd November, 9th September, 15th November, 15th September, 23rd November, 29th November, 3rd December, 16th December, and 14th September.

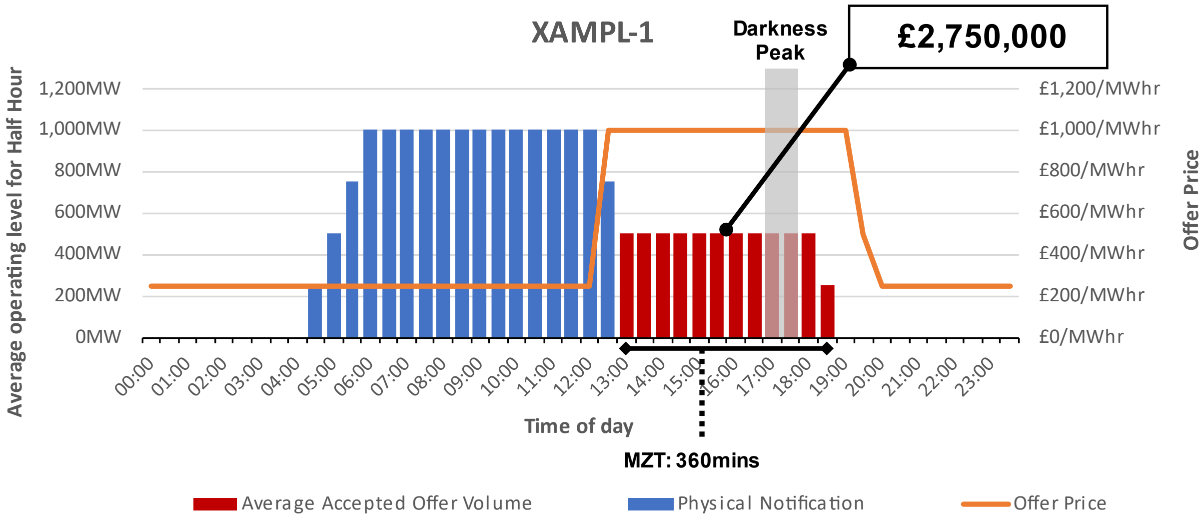
Annex 3: BMU Acceptance Data for 24th Nov

Data related to all generators with offers accepted by the Control Room across the darkness peak period (5-6pm) on 24 November 2021 are presented below in graphical form. All this data supporting the individual graphs is publicly available on BMRS.

BM start-up instructions can be found on SONAR.

To help interpret the graphs and data two illustrative generators are utilised as set out below.

Interpreting the graphs



Example Generator 1 (XAMPL-1) is extended through the Balancing Market across darkness peak (at a BM cost of £2.75m) as its MZT period renders the generator unavailable for the darkness peak without offer acceptance through the Balancing Market from 13:00 onwards. Note, this graph is not representative of the operating profiles for coal units.

The generator (BMU: XAMPL-1) has a Physical Notification (PN), to start generating at 04:30 and ramp up to full generating output of 1,000MW by 06:00. It plans to continue operating at this level until it begins a ramp down process towards de-synchronisation at 13:00 (i.e., coming off-load / a PN of 0 MW). These are the **blue bars**.

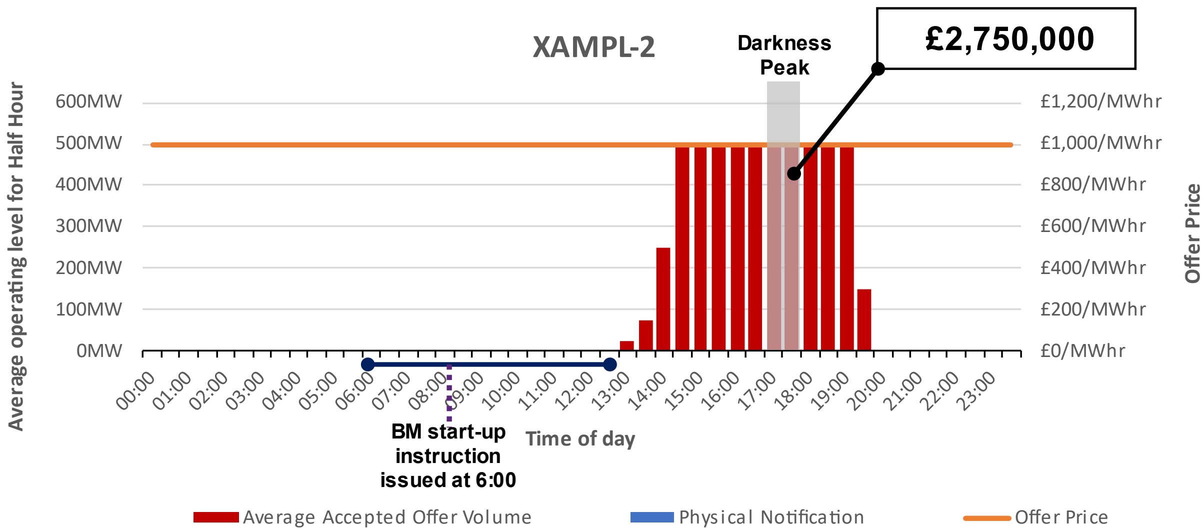
Up to this point the generator offers 1,000MW of contribution towards total available generation capacity and margin because that reflects its maximum output. However, whilst the generator is within its Minimum Zero Time (MZT) of 360 minutes (6 hours) following a de-synchronisation the contribution towards capacity and margin is 0 MW as the generator is not available to generate. For this generator, if it were to come off load (desynchronise) at 1pm it could not come on until 7pm (i.e., after the darkness peak). This is the **black line** on the x-axis from 13:00 to 19:00.

Across the day the Control Room must keep margin at adequate levels to meet potential demand and to maintain appropriate capability to continue supplying customers and consumers even if the largest generator were to unexpectedly fail. Therefore, if the margin were to drop below acceptable levels just for the darkness peak (**grey shaded area** from 17:00 to 18:00) the Control Room would need to delay the desynchronisation of this generator (XAMPL-1) and dispatch it on from 13:00 until after the darkness peak. In this example for 13:00 until 19:00. These are the **red bars**.

The generator provides a price for any increased output instructed / dispatched through the Balancing Market by the Control Room – the offer price. This can be changed by the generator and, in the example above, it increases from just above £200/MWhr to £1,000/MWhr for the period 13:00 to 19:00. This is the **orange line**.

In this example, the total cost of extending the generator through the balancing mechanism was £2,750,000 reflecting a 6-hour extension (irrespective of whether the capacity was only needed over the darkness peak).

MZT is a technical characteristic of a thermal generator and is there to account for thermal expansion / contraction issues from being taken off-load. One impact of this characteristic is that, for the relevant period post desynchronisation, there is an effective loss of capacity as it cannot run.



Example Generator 2 (XAMPL-2) is synchronised through the Balancing Market across darkness peak (at a BM cost of £2.75m), it has no original physical notification to generate and due to infrequent electricity generation does not start in a state of warmth which would enable the generator to respond within balancing mechanism timeframes so must be issued a BM Start-up instruction ahead of the requirement to deliver electricity. This is representative of coal units accepted through the balancing mechanism on 24th November.

The generator (BMU: XAMPL-2) has no Physical Notification (PN), to generate electricity across the day. Therefore, this graph has no **blue bars**.

Balancing mechanism units which do not frequently generate electricity may not be in a state of readiness to respond to a control room instruction within balancing mechanism timeframes (their Notice to Deviate from Zero time is greater than 90 minutes). Therefore, to gain access to the operating margin provided by this generator (BMU: XAMPL-2) a BM start-up instruction must be issued significantly ahead of electricity delivery. This is represented by the **dark blue line,** in this example this is issued at 06:00 to make the unit ready to respond by 13:00. A BM start-up instruction does not mean the generator must be accepted through the Balancing Market but is needed to make it available.

In this example, the total cost of extending the generator through the Balancing Market was £2,750,000 reflecting a 7-hour synchronisation through offer acceptance represented through the **red bars.**

BMU Final Physical Notifications, Final Prices and Accepted Offer level

Physical notifications are the average expected output for that period based on their overall ramp up and ramp down profiles and MZT is displayed from the settlement period in which the generator would have desynchronised without control room offer acceptance. This data does not represent any settlement data and generator cost is calculated through average offer volume × offer price per settlement period.

The generators are presented in alphabetical order.

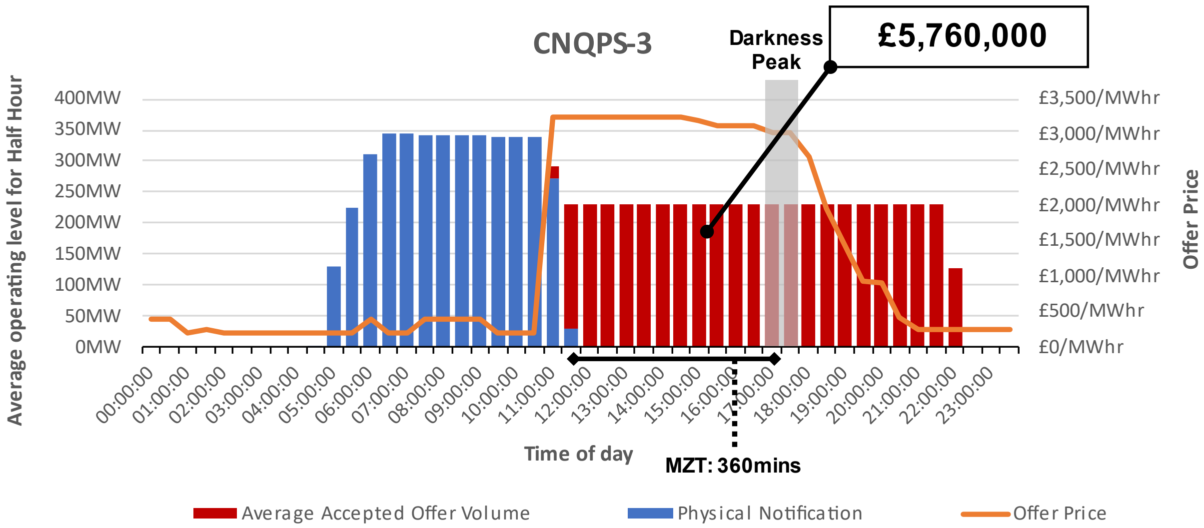


Figure 2: Connahs Quay Generator 3 was accepted through the BM on 24th November

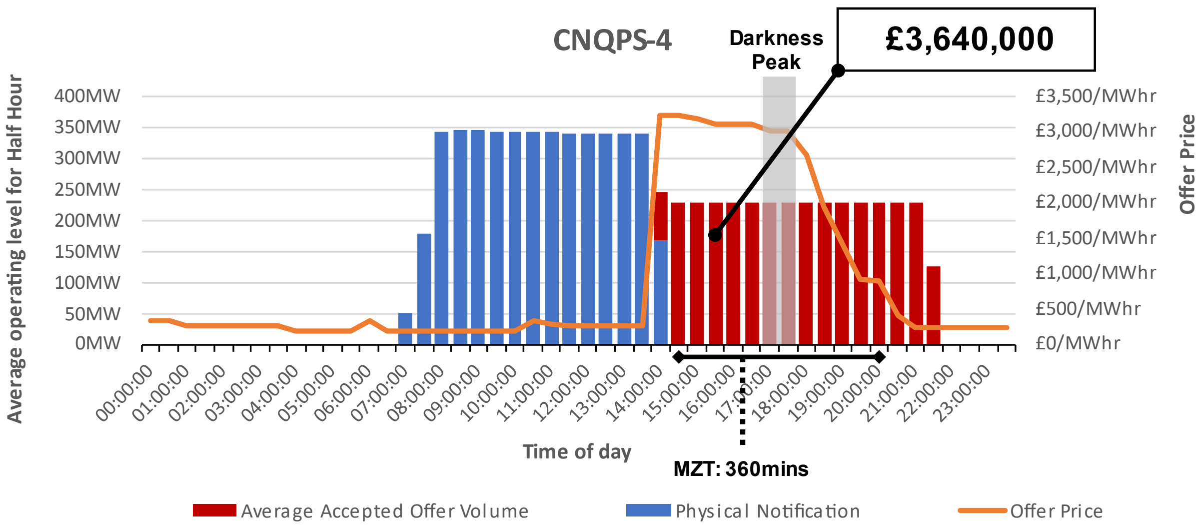


Figure 3: Connahs Quay Generator 4 was accepted through the BM on 24th November

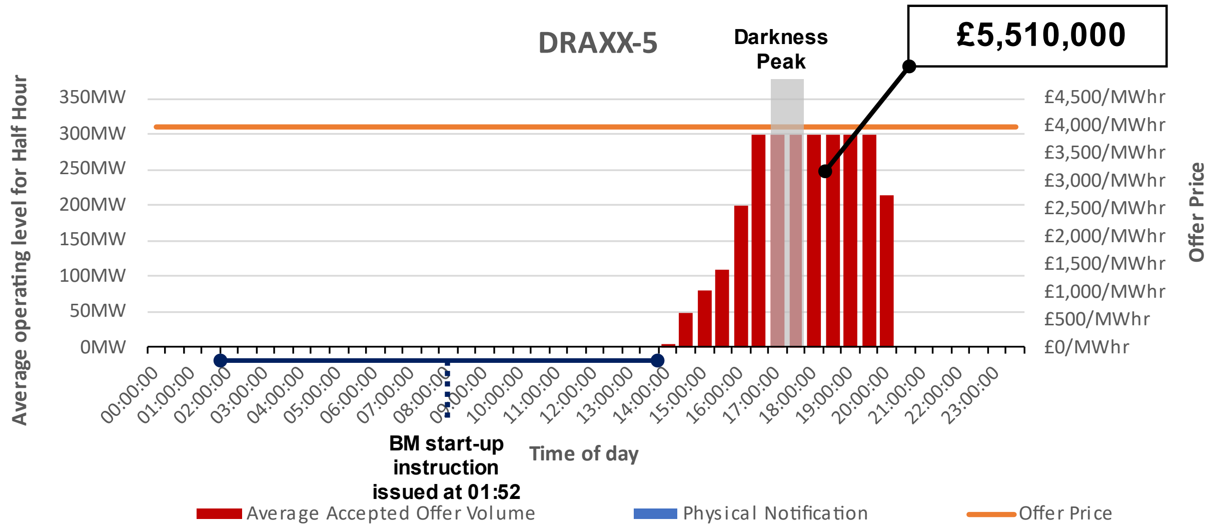


Figure 4: Drax Generator 5 was accepted through the BM on 24th November

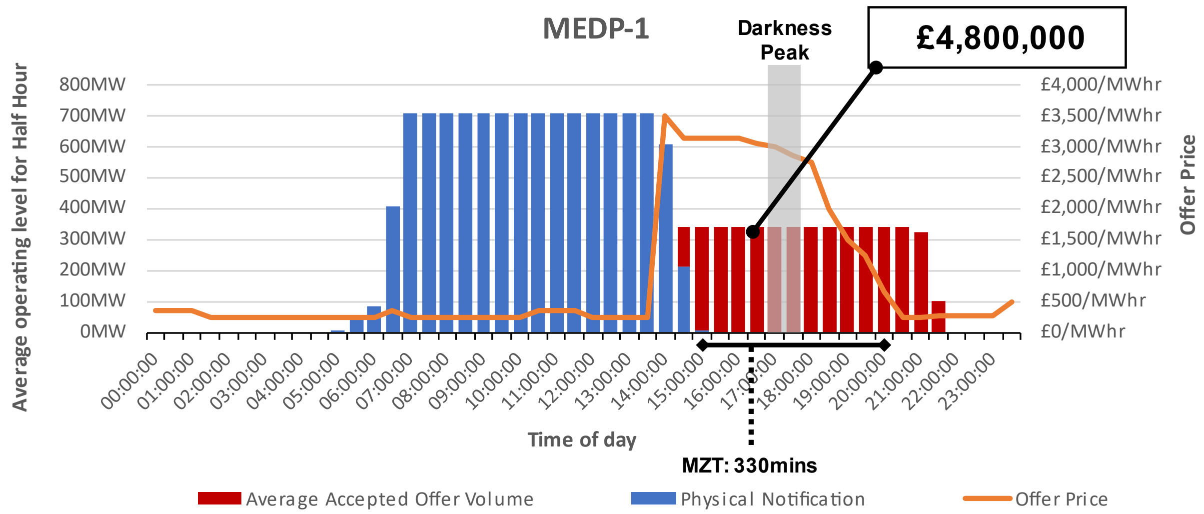


Figure 5: Medway was accepted through the BM on 24th November

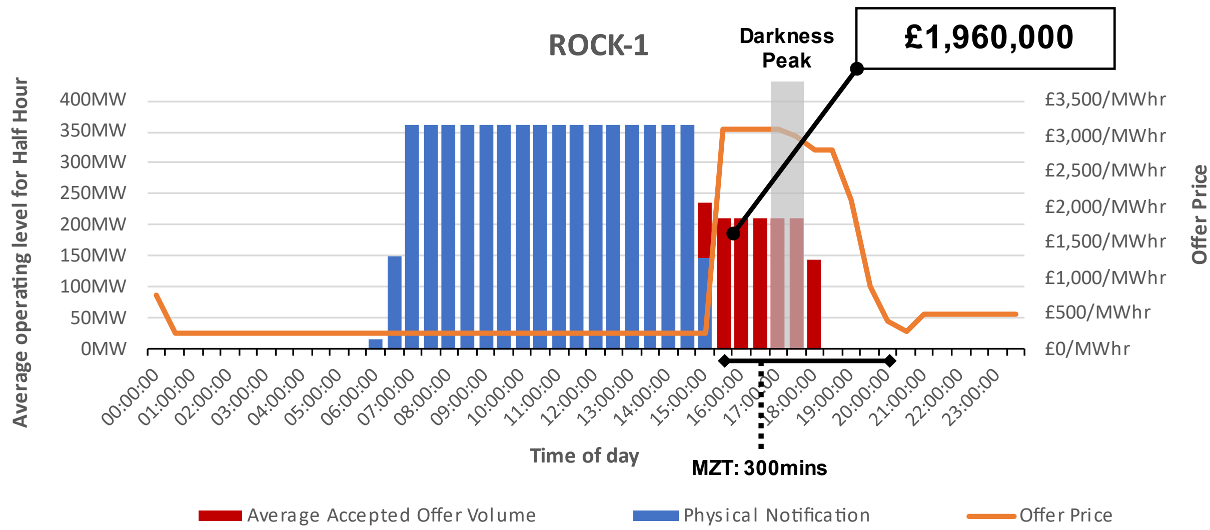


Figure 6: Rocksavage was accepted through the BM on 24th November

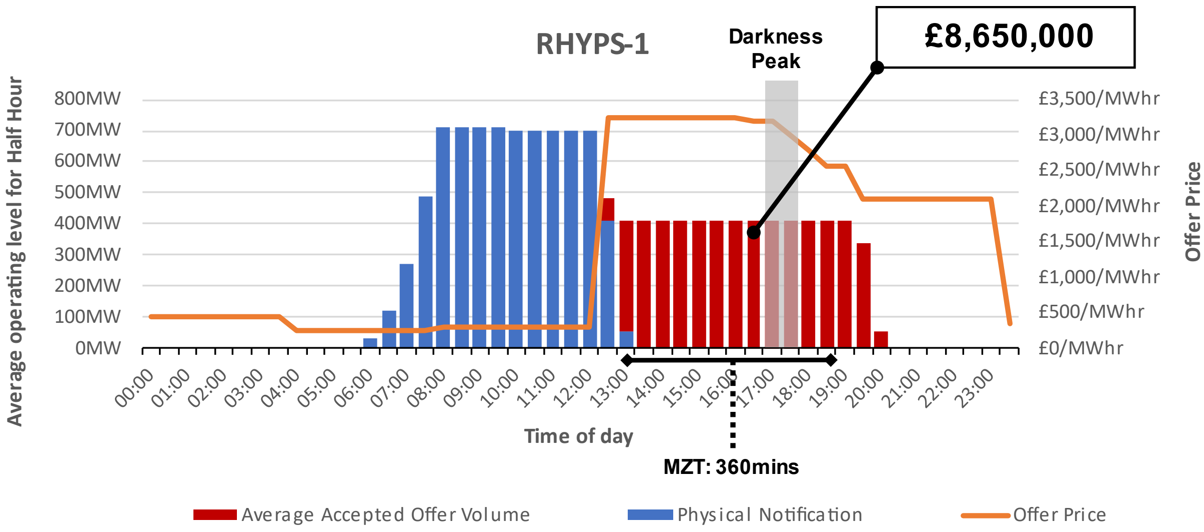


Figure 7: Rye House was accepted through the BM on 24th November

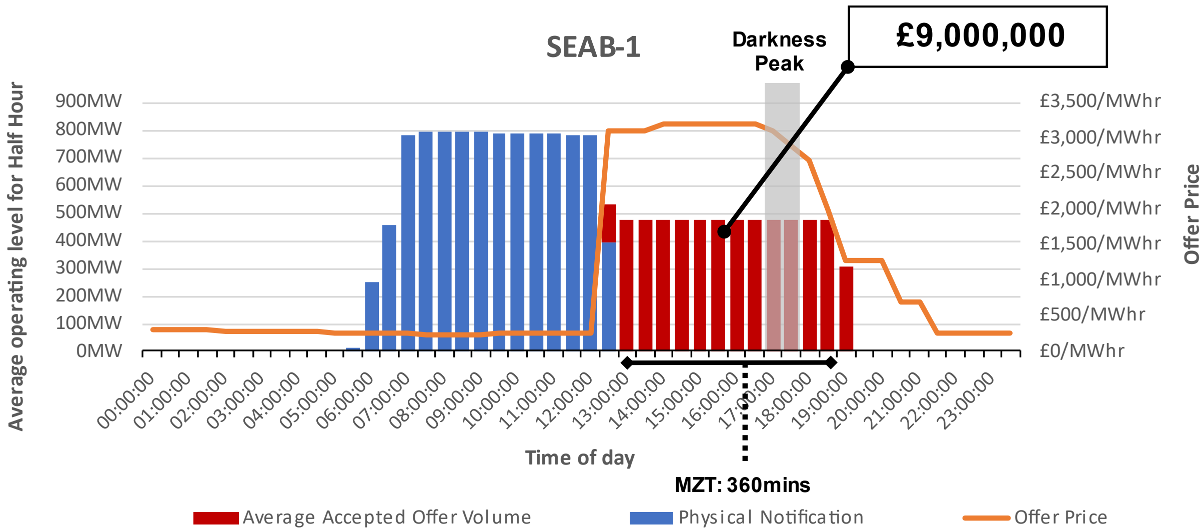


Figure 8: Seabank Generator 1 was accepted through the BM on 24th November

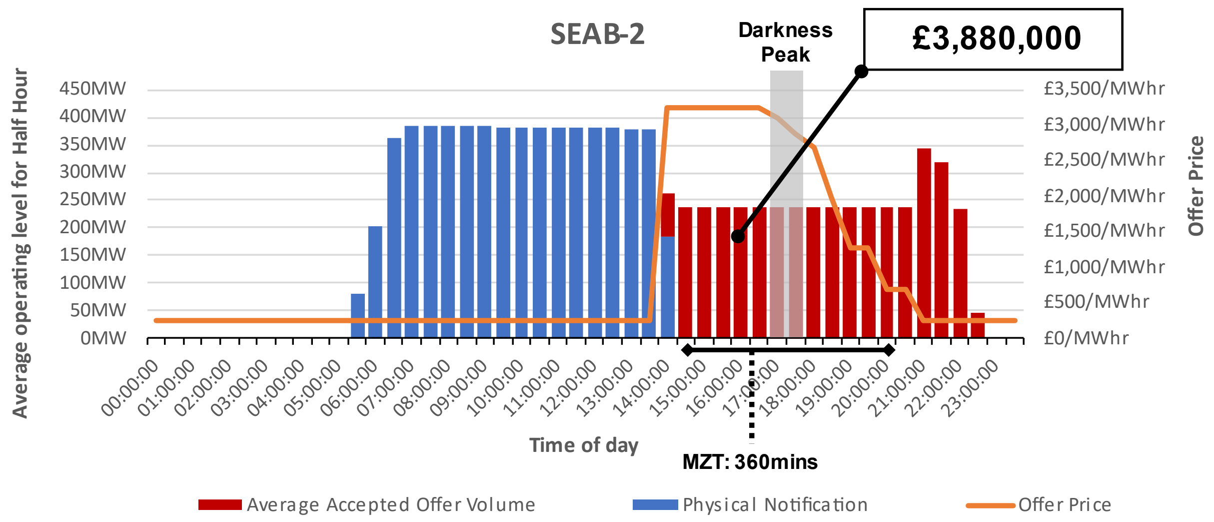


Figure 9: Seabank Generator 2 was accepted through the BM on 24th November

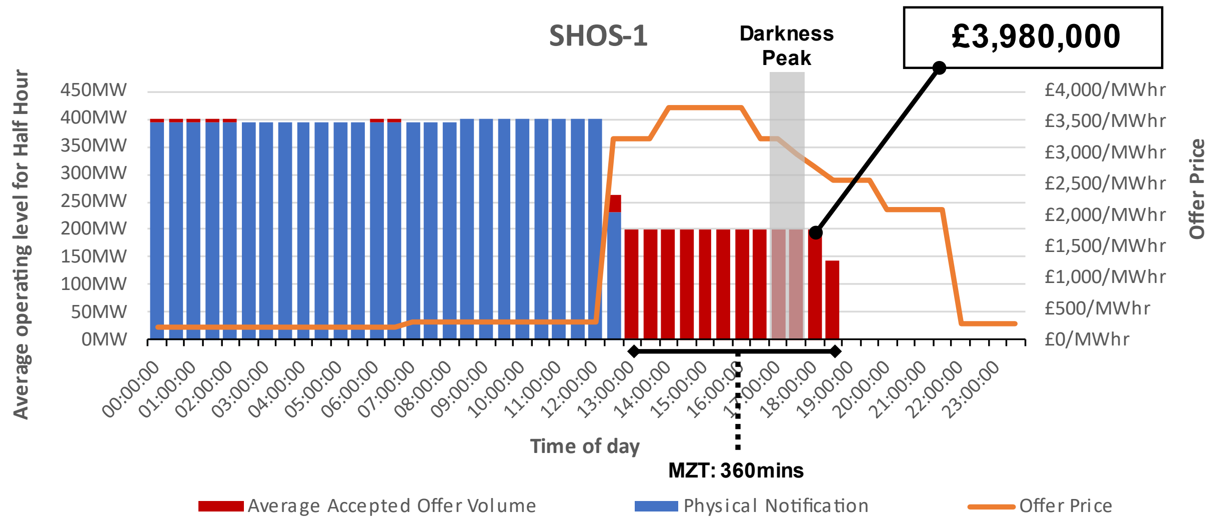


Figure 10: Shoreham Power Station was accepted through the BM on 24th November

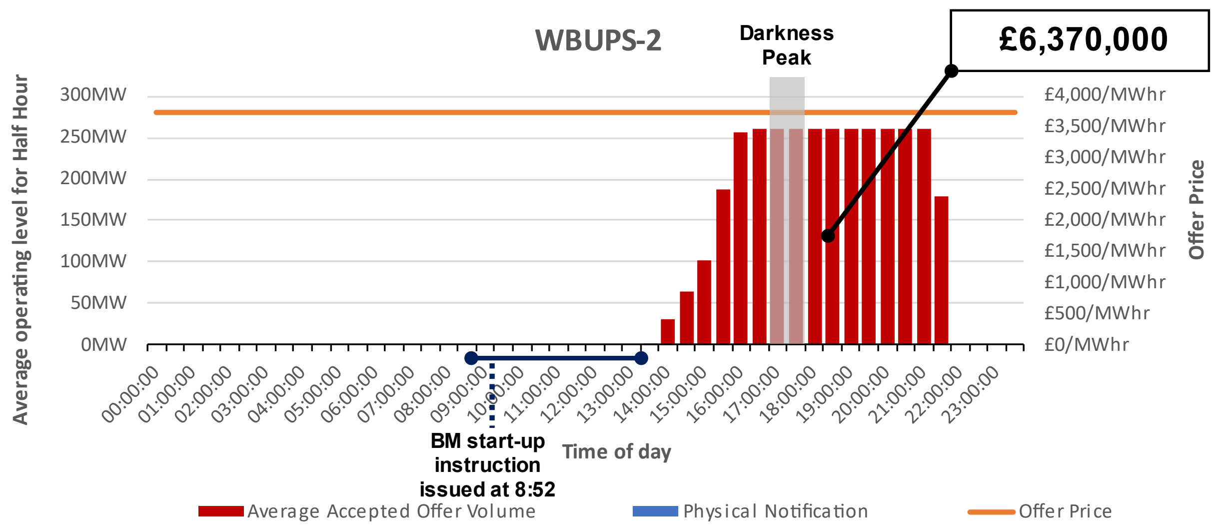


Figure 11: West Burton A Generator 2 was accepted through the BM on 24th November