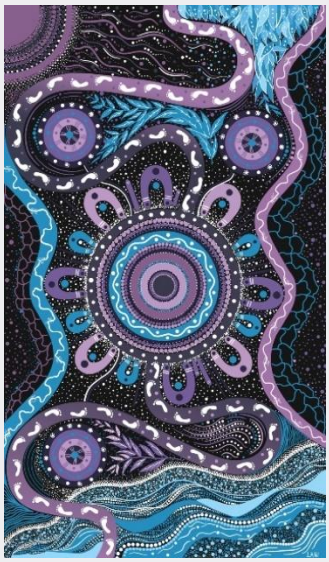
Investigation into demand forecasting and scheduling non-compliance – June 2025

April 2026

Assessment of DWGM demand forecasting and scheduling during the affected period and related non-compliance with the National Gas Rules.

A report for the Declared Wholesale Gas Market

Public



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO has prepared this report as part of AEMO's declared system functions under the National Gas Law as discussed at Gas Wholesale Consultative Forum (GWCF)), using information available as at 14 August 2025, unless otherwise specified.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this report but cannot guarantee its accuracy or completeness. Any views expressed in this report are those of AEMO unless otherwise stated, and may be based on information given to AEMO by other persons. Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this report:

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1 Introduction

Between 1 January 2025 and 25 June 2025, AEMO has identified and investigated a scheduling error affecting 39 gas days in the Declared Wholesale Gas Market (DWGM). The error was traced to a software defect that duplicated demand forecasts during data transformation prior to schedule input. This report outlines the nature of the issue, its root cause, regulatory implications, and AEMO's conclusion.

AEMO notes that under rule 208(5), demand forecasts submitted by any Market Participant are confidential. Therefore, this report is unable to go into detail about the demand forecasts duplicated and related details as doing so may disclose demand forecasts of specific Market Participants.

Although the error existed from 1 January 2025 onwards, the average extra uncontrollable withdrawals scheduled between January to May 2025 was below 0.3 TJ/d, which is similar to daily demand fluctuations and not included in the investigation. AEMO identified the error on 25 June 2025 and initiated an emergency change to implement a software fix to resolve the defect.

This event does not meet the criteria under rule 217(1) for an unintended schedule result.

In accordance with rule 217(3) of the National Gas Rules, an error made in determining a market price or a pricing schedule is not an unintended scheduling result and as such is not covered by the dispute resolution process for the purpose of compensation.

2 Event details

AEMO's scheduling process

Market Participants submit market bids (injection and controllable withdrawals) and demand forecasts for each standard schedule for each gas day via the WebExchanger. AEMO then collates these input data from Market Participants and prepares its own input data. AEMO's key input into the scheduling process includes AEMO's demand forecasts and demand forecast overrides (when required), end of gas day linepack target, constraints, intraday adjustments for injection or controllable withdrawals and other relevant input data.

AEMO then runs the Market Clearing Engine (MCE) based on the input data to produce the optimal schedules. AEMO will assess the schedules produced by the MCE and if the MCE results are accepted, will issue the pricing and operating schedules or reassess the input data and repeat the process. This occurs for each of the five current day schedules, three D+1 schedules and the D+2 schedule run each day.

Cause of the issue

AEMO implemented a change at the start of 2025 in the demand forecasts table in the scheduling database. Whilst testing was conducted before the change was implemented into production, a defect in the demand forecasting system (DFS) software's data aggregation logic when joining data from two tables in the demand forecast database caused some demand forecast data to be duplicated.

When a Market Participant submits their demand forecasts in the WebExchanger, their demand forecasts flow into the scheduling database which is then displayed in the DFS application. Demand forecasts are then

reviewed, and nodal demand is generated once approved. The error occurred during the transformation of demand forecasts into hourly nodal demand which is then used by the MCE to produce the pricing and operating schedules.

The duplication of demand forecasts did not occur in the Settlements database.

Figure 1 shows the demand forecasts process.

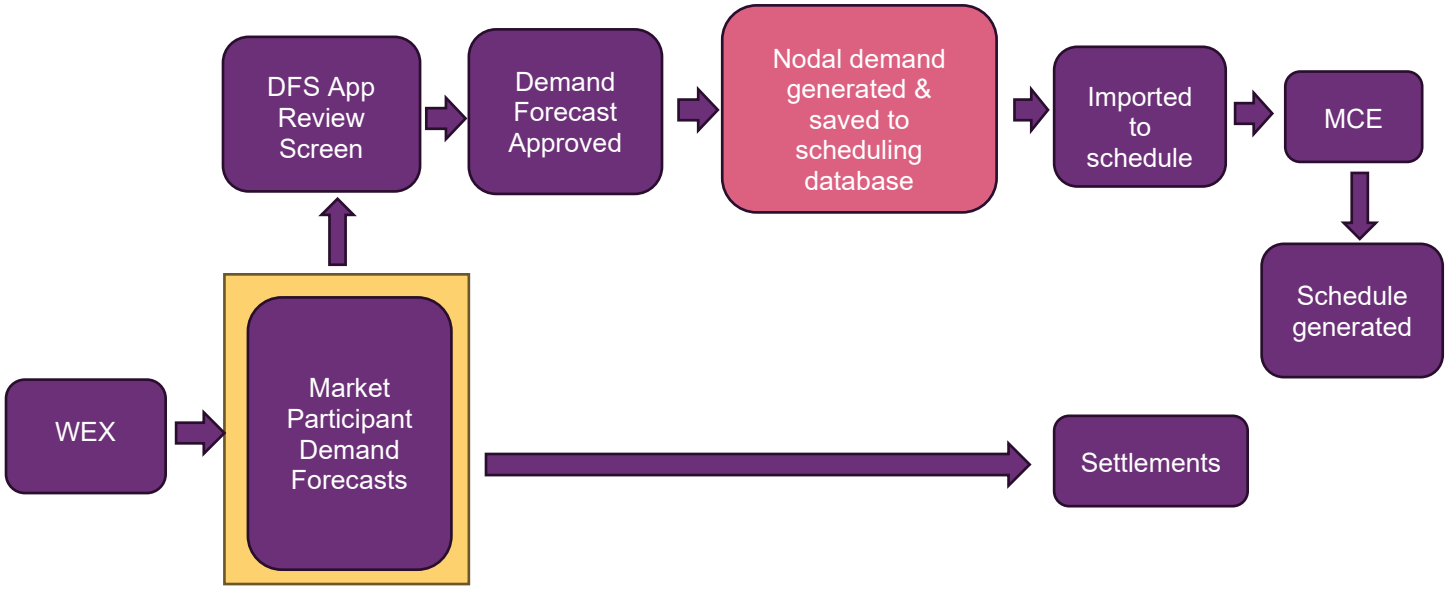

Figure 1 Demand forecast process

Testing process

Prior to any implementation of a change, AEMO will undertake user acceptance testing (UAT) to ensure that the change is implemented correctly. The testing for this change occurred in two stages.

The first stage was a baseline validation to ensure that forecasts can be submitted, and the correct INT reports are generated.

1. Submit current day demand forecasts through WebExchanger.
2. Check that the demand forecasts submitted are populated in the demand forecast table in the scheduling database.
3. Check that the INT report has been generated and the demand forecasts are shown in the INT report.
4. Check that the aggregated demand forecasts in DFS match.

The second stage of the testing was to ensure the correct settlement outcomes for the market participant.

1. Submit current day demand forecasts through WebExchanger.
2. Check that the aggregated demand forecasts in DFS match.
3. Generate nodal demand in DFS.
4. Submit, review and approve pricing and operating schedules.
5. Check that the demand forecasts have flowed through to the Settlements database.
6. Check that the Settlements outcome reflects the demand forecasts submitted.

During testing, an issue was identified that the demand forecasts table in the scheduling database was not properly filtering out inactive demand forecasts entries and passing them through to the DFS application and Settlements database. This defect was raised and fixed. Testing was then repeated to ensure that the demand forecasts table in the scheduling database is filtering out inactive demand forecasts entries and not passing them through to DFS and the Settlements database.

Identification of error

When schedules are generated, they are reviewed before they are approved. However, in this case, the duplication of demand forecasts was not easily identifiable in the current day forecasts due to the difference in the way data is displayed in the DFS application and the Transportation Market Manager (TMM) application, which is the scheduling interface for the MCE.

For example, for the 10AM schedule:

1. DFS uses extrapolated actual demand for the first 4 hours (6AM schedule) then forecasts for the next 20 hours.
2. TMM uses uncontrollable withdrawal quantity scheduled in the 6AM schedule for the first 4 hours and then the forecasts from DFS for the next 20 hours.

Therefore, when reviewing the uncontrollable withdrawal forecasts in the TMM application and the aggregated demand forecasts from the DFS application, those numbers would not align as DFS uses extrapolated actual demand and TMM uses scheduled quantity for hours that have passed.

Since demand forecasts tend to be lower outside of winter, the error was not easily detected. On 25 June, AEMO identified a large discrepancy between the uncontrollable withdrawal quantity displayed on TMM and the aggregated demand forecasts in DFS in its D+1 schedule.

Implementation of fix

AEMO immediately investigated the data discrepancy and confirmed the existence of the duplicated forecasts in the scheduling inputs. The issue was promptly recognised as originating from a defect in the underlying software code, which resulted in the duplication of demand forecast data during its transformation to hourly nodal demand.

A fix was quickly developed and then implemented into a lower environment so that testing and verification could be performed. A re-run of the same D+1 schedule in UAT showed that there were no discrepancies between the uncontrollable withdrawal quantity displayed in TMM and the aggregated demand forecasts in DFS.

An emergency change was raised, and the software fix was implemented in the pre-production and production environments. The software defect was resolved before then 10PM current day schedule on 25 June.

3 Impacts

In relation to the impact the defect had on system operations, the presence of duplicate demand forecast values resulted in higher quantities of gas being scheduled for injection earlier in the day leading to higher linepack in the system. This provided AEMO with an increased operational linepack buffer intra-day which has a similar effect to the profiling of Longford injections on very high demand days. This outcome would have had a slightly positive impact on the operations of the Declared Transmission System (DTS) during May and until 25 June 2025.

Table 1 summarises the average daily nodal demand and the average daily "extra" uncontrollable withdrawals that were scheduled due to the error, broken down by month.

Month	Average daily nodal demand (TJ)	Average Daily Extra Uncontrollable Withdrawals (TJ)	Average Percentage of Nodal Demand
January	249.71	0.13	0.05%
February	269.70	0.27	0.10%
March	271.81	0.15	0.05%
April	325.44	0.06	0.02%
May	538.83	0.10	0.02%
June	904.68	19.77	2.19%

Table 1 Average daily extra uncontrollable withdrawals scheduled monthly

For the first five months of 2025, the average extra uncontrollable withdrawals scheduled was below 1 TJ/d (under 0.1% of total demand), which is similar to daily demand fluctuations. Assessment of the impact was only conducted for the month of June 2025 as the average daily extra uncontrollable withdrawals scheduled was approximately 2.2% of daily demand.

Assessment of impact

For assessment purposes only, AEMO re-ran schedules in UAT from 1 June to 25 June 2025 to determine the high-level impact of the demand forecasting defect. AEMO did not change market participants bids or demand forecasts for the re-run schedules. Different scheduling outcomes throughout the day could have led to changes in actual bidding and forecasting behaviours.

The following adjustments were made to re-run the schedules:

1. Hourly nodal demand was revised with the duplicated nodal demand data removed.
2. Linepack input data was recalculated for each current day schedule to provide an estimate of revised system starting conditions.
3. Some participants' quantities were adjusted to reflect its alignment with their accreditation (if applicable).
4. Output data from previous schedules were used in the following schedules.
5. The current day schedules (6AM, 10AM, 2PM, 6PM and 10PM) were then re-run for the days impacted by the error in June.

Figure 2 and Figure 3 shows the results of the re-run schedules. Figure 2 shows the difference between the original nodal demand and the re-run nodal demand where duplicated nodal demand data were removed.

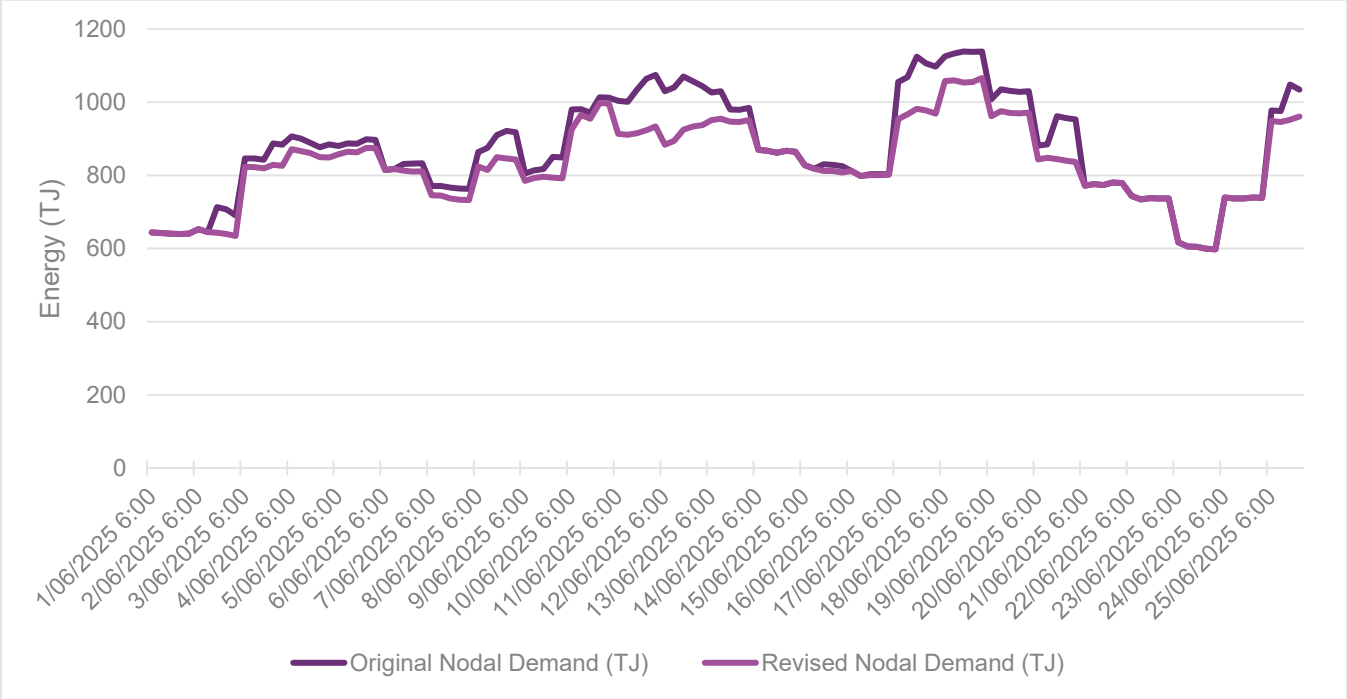

Figure 2 Comparison between original and revised nodal demand

Figure 3 shows the difference between the original controllable injections and withdrawals and the re-run controllable injections and withdrawals.

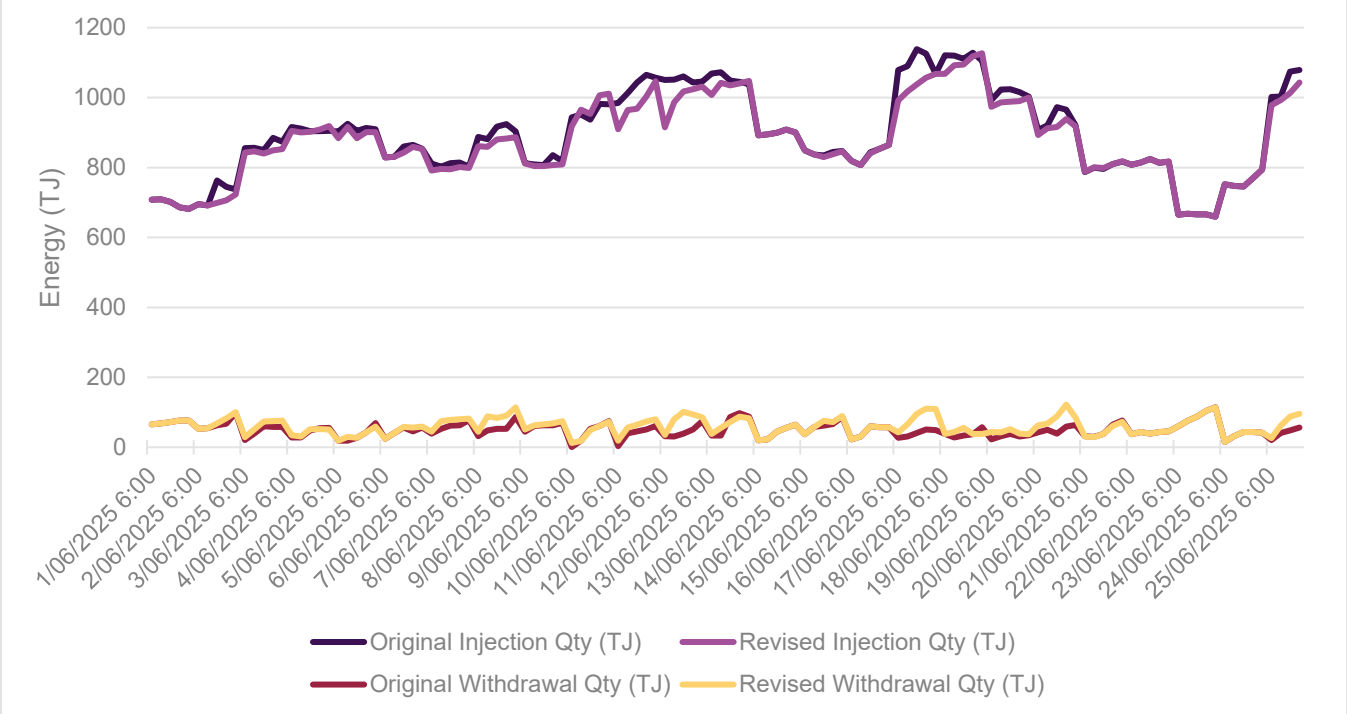

Figure 3 Comparison between original and revised injections and withdrawals

Uncontrollable withdrawals are not displayed as market participants' demand forecasts in the original and re-run schedules were the same. The error occurred during the transformation of some market participants' demand forecast into hourly nodal demand in the scheduling system.

Market price fluctuates throughout the day due to factors such as demand changes and market participants bidding behaviour. In June, the average market price was approximately $12/GJ with higher market prices on 12 and 18 June.

Figure 4 shows a comparison of market price between the original schedule and the revised schedule.

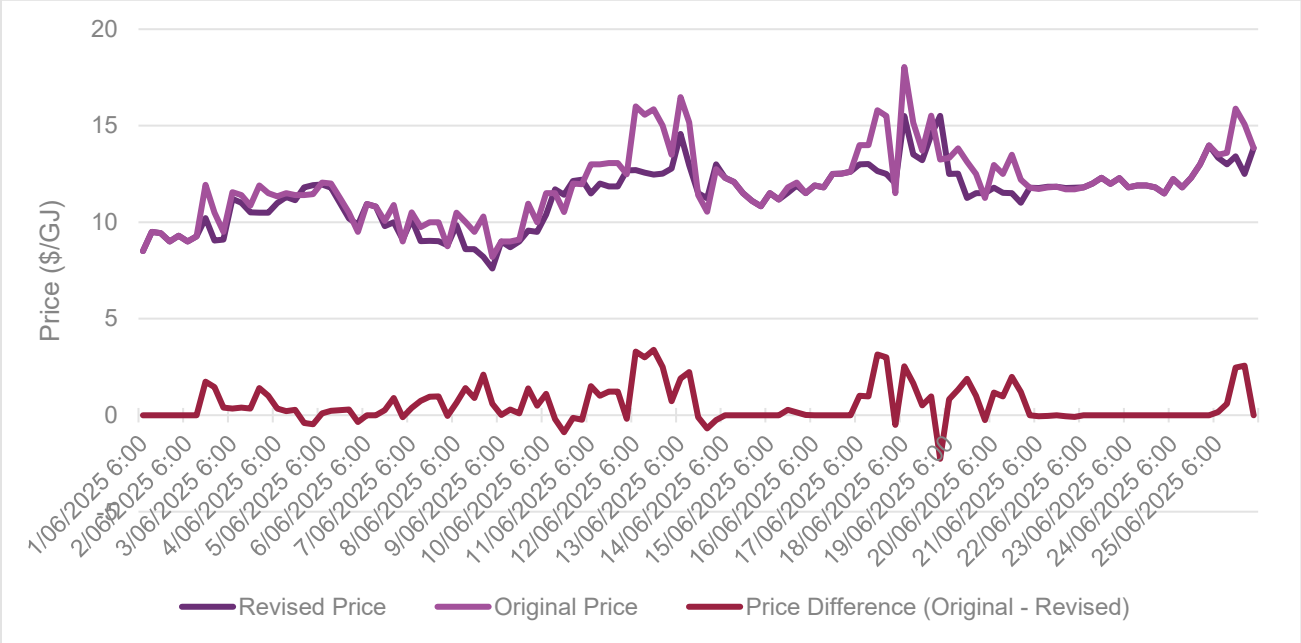

Figure 4 Comparison between market price in the original schedule and the revised schedule

Estimated market impact using re-run schedules

AEMO has endeavoured to assess market impact through a theoretical assessment of market outcomes for the purpose of this report only, noting this is not the actual impact to participants and that during the impacted period, gas was still correctly injected, withdrawn and flowed in the DTS as per schedules and the duplication of demand forecasts did not occur in the Settlements database.

To estimate market participants' theoretical market impact, Market Participants' allocation data would need to be revised as some of their scheduled quantities have changed in the re-run schedules. An assumption was made that if the market participant was scheduled, the facility operator would allocate that quantity of gas to the market participant. While generally true, this doesn't necessarily hold in all situations.

If the scheduled quantity for a Market Participant in the original schedule and the re-run schedule was unchanged, their allocation data is not revised. If the scheduled quantity in the re-run schedule is different, then the allocation data is revised. The revised allocation data is re-calculated by using the original scheduled quantity and allocation data for each Market Participant at each controllable injection and withdrawal point to obtain a ratio. This ratio is then applied to the revised schedule for each Market Participant at each controllable injection and withdrawal point to obtain the revised allocation data.

The revised allocation data is then used to re-run Settlements to obtain the revised estimated theoretical market impact.

From the analysis, the estimated aggregate theoretical net market impact is approximately 3% of the total settlement amount for gas traded in the DWGM in June 2025 (approximately $2.7 million compared to $87 million). This shows the overall estimated effect on the market, and each participant's theoretical market outcomes would differ given changes in individual scheduling outcomes, noting that during the impacted period, gas was still correctly injected, withdrawn and flowed in the DTS as per schedules.

Given the extended duration over which the error had occurred, the theoretical net market impact provided in this report is indicative only, given the limitations and assumptions AEMO has had to made to re-run the schedules and settlements.

During the impacted period, gas was still correctly injected, withdrawn and flowed in the DTS as per scheduling instructions.

4 Assessment of the event

As indicated in Table 2, AEMO has determined that schedules impacted by the demand forecast error did not comply with the National Gas Rules.

AEMO has submitted a wholesale energy self-report to the Australian Energy Regulator.

Table 2: Assessment of the event

National Gas Rules **Rule 215(2)** **The inputs and assumptions set out in subrule (1) must be applied by AEMO to produce operating schedules which specify injections and withdrawals for each hour of the gas day in a way that minimises the cost of satisfying expected demand for gas over that gas day using valid demand forecasts and bids submitted by Market Participants and taking into account:** **...** **Rule 221(1)** **AEMO must use the following inputs and assumptions for the purpose of producing operating schedules:** **(a) the demand forecasts and bids submitted by Market Participants in respect of that gas day prior to the**	The rules specify that valid demand forecasts submitted by Market Participants are to be used as an input. In this case, while valid demand forecasts were used, the underlying defect in the software code caused some demand forecasts data to be duplicated.

Table 2: Assessment of the event	
times specified in rule 211, including any conditions or constraints included in the bids in accordance with rule 209(8); **…** **Rule 221(3)** **AEMO must have regard to the following matters so far as relevant to the production of the pricing schedules for a scheduling horizon:** **…** **(b) the total of valid demand forecasts submitted by all Market Participants** **…**	
(a) NGL s91BN(2) If AEMO suspects a breach of the Wholesale Market Procedures, it must make a decision as to whether the breach is a material breach.	AEMO does not consider there has been a breach of the Wholesale Market Operations Procedures (as opposed to this being a rules breach).

5 Further actions

AEMO has reviewed the causes of the event and is undertaking the following actions to address the cause of the event:

- The fix implemented on 25 June is in effect and will prevent the same issue from occurring again.
- Updates are being made to the post-scheduling review process to improve the checks that monitor consistency between market participant aggregate forecasts and nodal demand for forward looking hours. This will better enable AEMO to detect any discrepancies in demand forecast data during the scheduling process.
- Automated alerts are being enhanced to ensure that inconsistencies between market participants' aggregated demand forecasts and nodal demand can be sent to relevant teams to enable quick detection and resolution.
- Internal application screens are being enhanced to improve the way that demand forecasting information is displayed for the schedule review process.