INTERVENTION PRICING METHODOLOGY CONSULTATION

ISSUES PAPER

Published: **June 2018**

CONTENTS

1. STAKEHOLDER CONSULTATION PROCESS

AEMO is consulting on proposed amendments to the Intervention Pricing Methodology[1] in accordance with the Rules consultation procedures in National Electricity Rules (NER) clause 8.9.

AEMO's indicative timeline for this consultation is outlined below. Dates may be adjusted depending on the number and complexity of issues raised in submissions and any meeting with stakeholders.

DELIVERABLE	Indicative Dates
Issues Paper published	29 June 2018
Submissions due on Issues Paper	06 August 2018
Draft Report published	31 August 2018
Submissions due on Draft Report	17 September 2018
Final Report published	26 October 2018

Before the submissions due date, stakeholders can request a meeting with AEMO to discuss the issues and proposed changes raised in this Issues Paper.

2. BACKGROUND

2.1 NER Requirements

The Intervention Pricing Methodology is made under NER clause 3.9.3(e), which requires AEMO to develop a methodology to determine dispatch prices and ancillary service prices to apply during an AEMO intervention event.

In accordance with NER clause 3.9.3(b), AEMO must use the published Intervention Pricing Methodology to set the dispatch price and ancillary service prices at the value which AEMO, in its reasonable opinion, considers would have applied had the AEMO intervention event not occurred.

2.2 Context for this Consultation

AEMO identified issues with the intervention pricing and directions process during the course of various direction events in early 2017. In June 2017, AEMO engaged consultants (SW Advisory and Endgame Economics) to undertake a comprehensive review of the Intervention Pricing and Directions process. The consultant's final report[2] (produced in October 2017) outlined recommendations for improvements to the Directions process as well as alternative methodologies for Intervention Pricing.

To seek industry feedback on the recommended alternative approaches for the Intervention Pricing Methodology, AEMO established the Intervention Pricing Working Group (IPWG). The IPWG was open to all interested parties in the energy industry and consisted of representatives from 14 organisations, including thermal and renewable generators, settlement residue unit holders and the AEMC.

Between November 2017 and May 2018, AEMO held five meetings with the IPWG. The issues (covered in Section 4) and the proposed changes to the methodology (covered in Section 5) were discussed extensively at the IPWG meetings. There was strong support from the IPWG at the last meeting (held on 30 May 2018) for AEMO to proceed with consultation on proposed changes in the Intervention Pricing Methodology.

[1] Available here: https://www.aemo.com.au/-/media/Files/PDF/Intervention-Pricing-Methodology-October-2014.pdf
[2] Consultant report ('Intervention Pricing Final report') is included in the IPWG Meeting 1 – Meeting Pack available here: https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

2.3 NER terms

This Issues Paper uses several terms that are defined in the NER. These have the meanings set out defined in Chapter 10 of the NER.

3. INTERVENTION PRICING PROCESS

AEMO declares intervention pricing for periods subject to an AEMO intervention event, defined in the NER as the issue of a '*direction*' (but not a '*clause 4.8.9 instruction*'), or the dispatch or activation of contracted reserves under the reliability and emergency reserve trader provisions. Under intervention pricing, NER 3.9.3(b) requires that AEMO set the dispatch price and ancillary service prices at the value which AEMO, in its reasonable opinion, considers would have applied had the intervention event not occurred. AEMO determines and publishes these prices in accordance with the Intervention Pricing Methodology.

During intervention pricing periods, AEMO performs two National Electricity Market Dispatch Engine (NEMDE) runs to generate dispatch targets and spot prices. Dispatch targets are produced from an Outturn (physical) run that takes its inputs from the physical system and includes the impact of the intervention itself. Energy and ancillary service prices are produced from a Pricing ('what-if') run that attempts to simulate how power system (and spot prices) would have evolved absent the AEMO intervention event.

4. ISSUES WITH THE EXISTING INTERVENTION PRICING METHODOLOGY

4.1 Issue 1: Inconsistent inputs to feedback constraints in Intervention Pricing run

Under certain circumstances, the energy and ancillary service prices produced in the Pricing runs are unrealistic, given the power system conditions at the time. During these events, unexpectedly high prices may be seen in regions other than the region for which the relevant direction was issued.

This was highlighted operationally on two separate occasions when directions in South Australia (SA) produced unexpectedly high prices in New South Wales (NSW) and Queensland (QLD).

- 9 February 2017 1550 hrs to 1900 hrs – Unexpectedly high prices in NSW, QLD.
- 13 January 2018 dispatch intervals (DIs) ending 1225 hrs and 1615 hrs – Unexpectedly high prices in QLD.

It should be noted that high prices in regions that are not subject to a direction is not an implausible scenario. However, given the power system conditions during the above events, the What-if prices in NSW and QLD did not reflect the prices that would reasonably have been expected in those regions had the intervention not occurred.

Figures 1-5 below provide a comparison of the prices between the Pricing run ("What-If price") and the Outturn run ("Outturn price") during the 9 February 2017 event.

Figure 1 Comparison of NSW What-If price and Outturn price on 9 February 2017

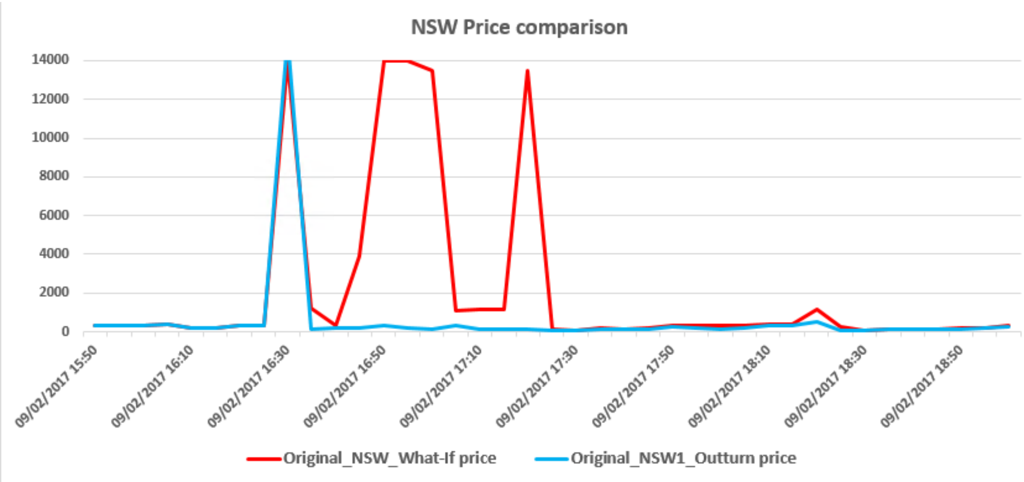


Figure 2 Comparison of QLD What-If price and Outturn price on 9 February 2017

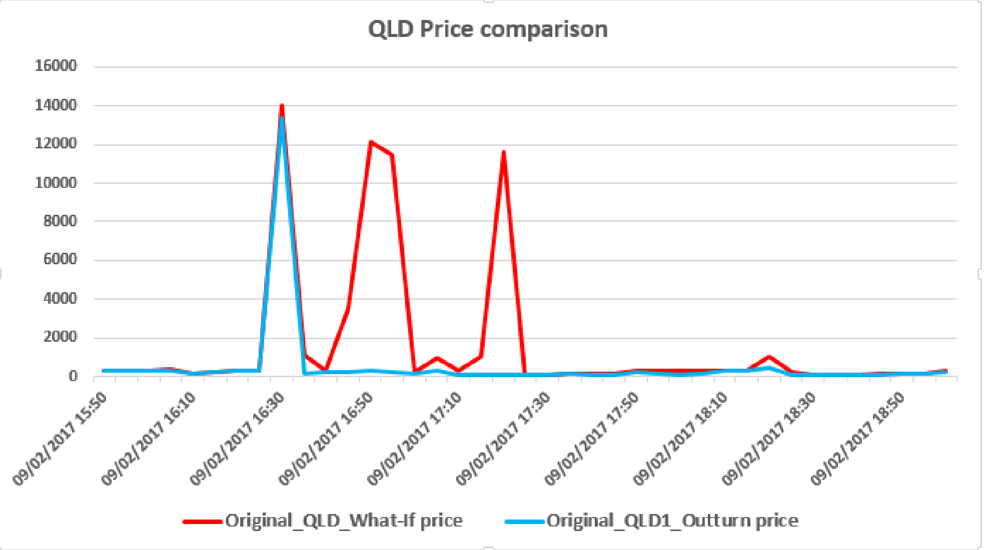


Figure 3 Comparison of SA What-If price and Outturn price on 9 February 2017

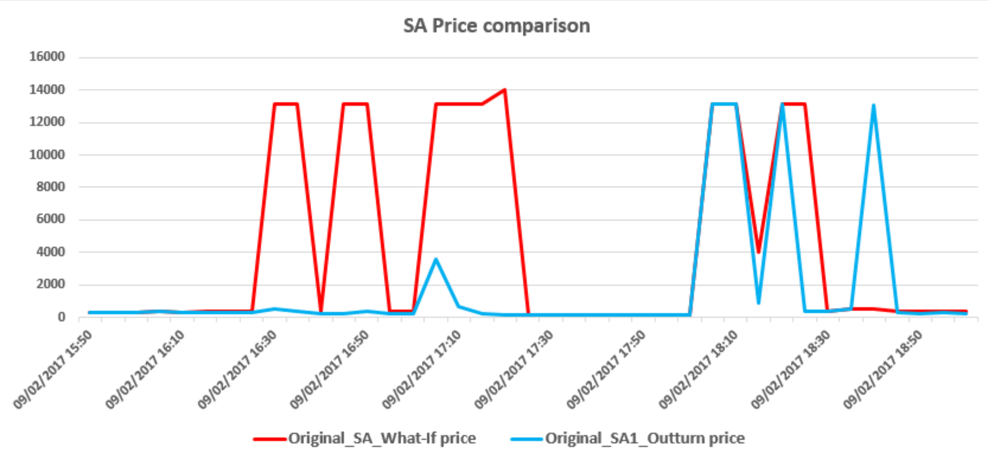


Figure 4 Comparison of TAS What-If price and Outturn price on 9 February 2017

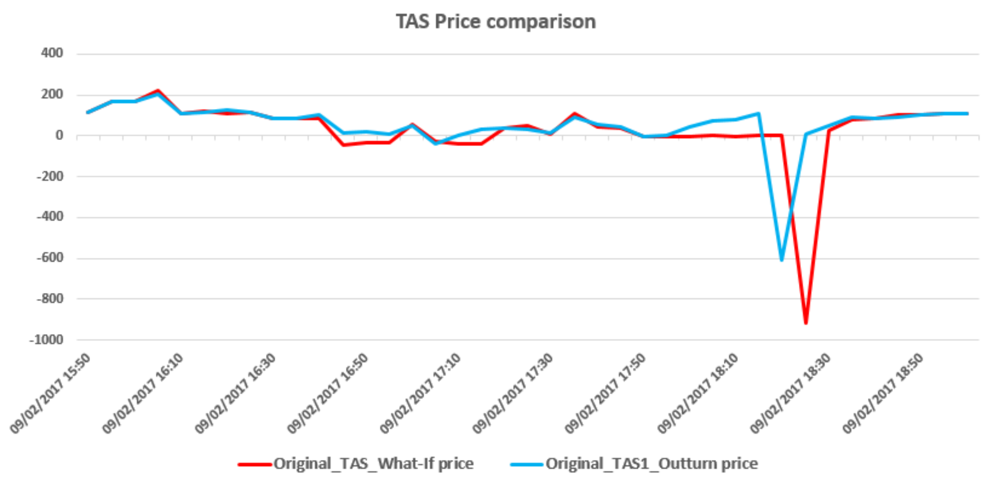
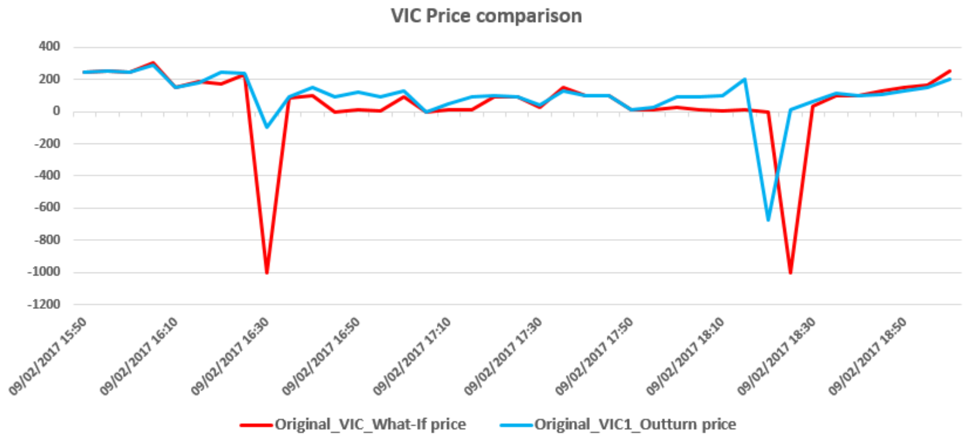


Figure 5 Comparison of VIC What-If price and Outturn price on 9 February 2017



Figures 6-10 below provide a comparison of the prices between the Pricing run ("What-If price") and the Outturn run ("Outturn price") during the 13 January 2018 event.

Figure 6 Comparison of NSW What-If price and Outturn price on 13 January 2018

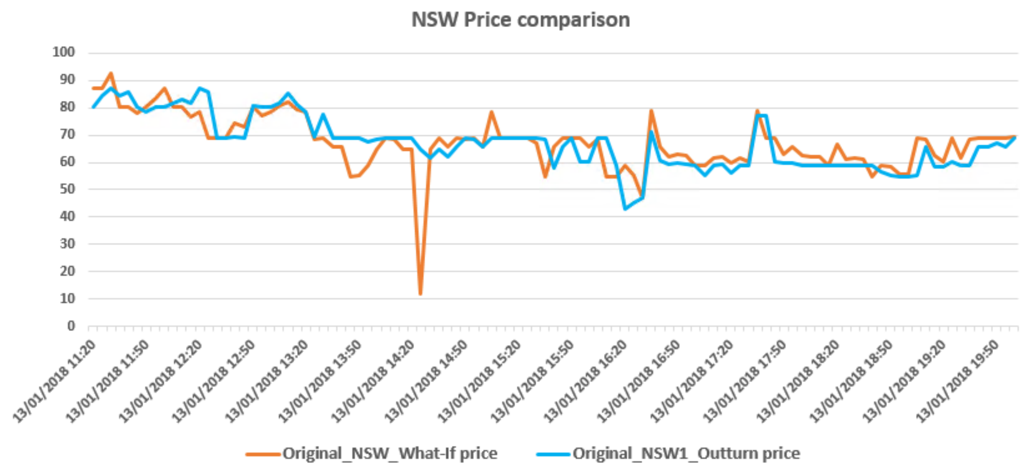


Figure 7 Comparison of QLD What-If price and Outturn price on 13 January 2018

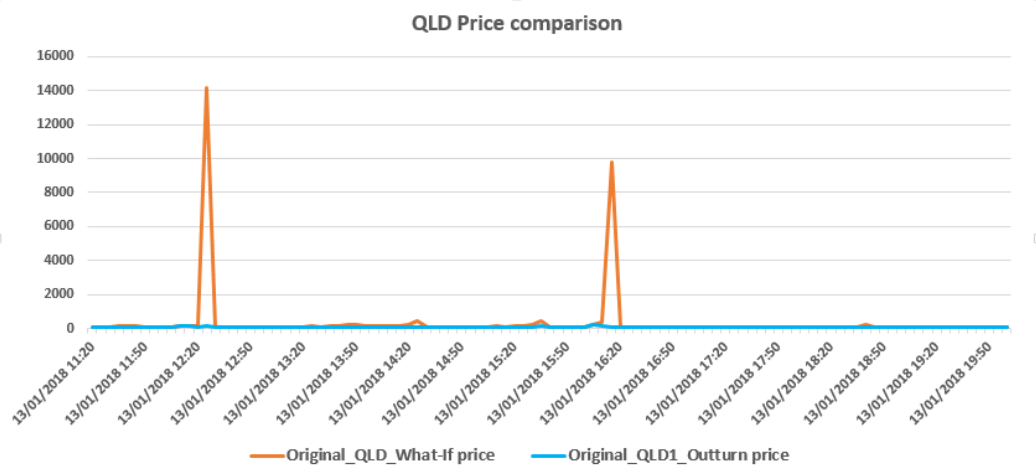


Figure 8 Comparison of SA What-If price and Outturn price on 13 January 2018

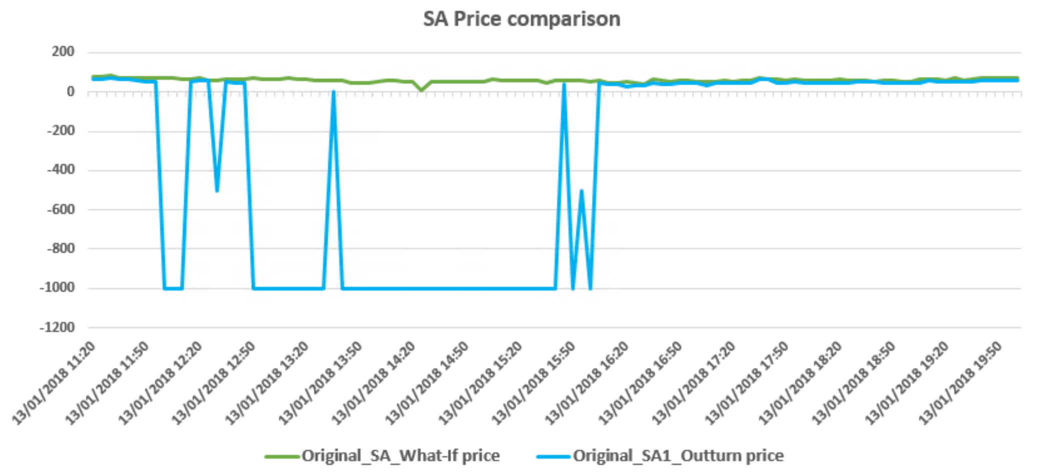


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Figure 9 Comparison of TAS What-If price and Outturn price on 13 January 2018

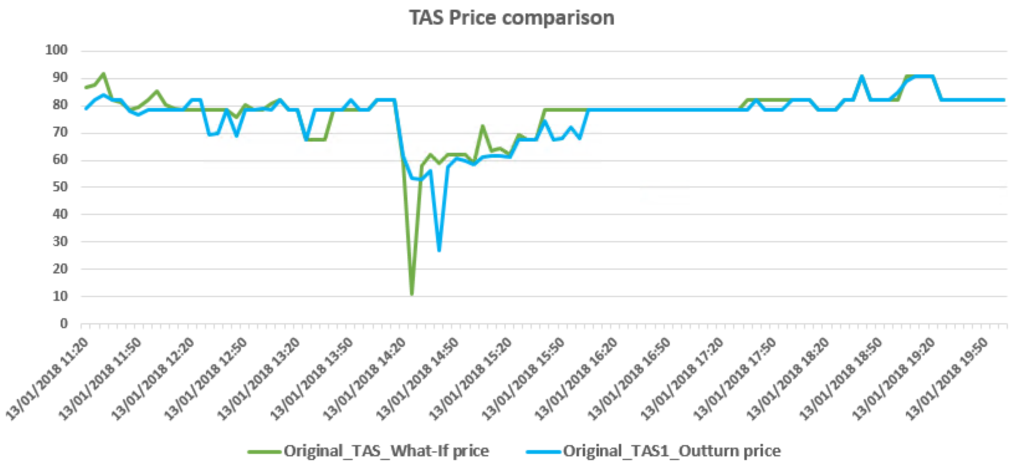
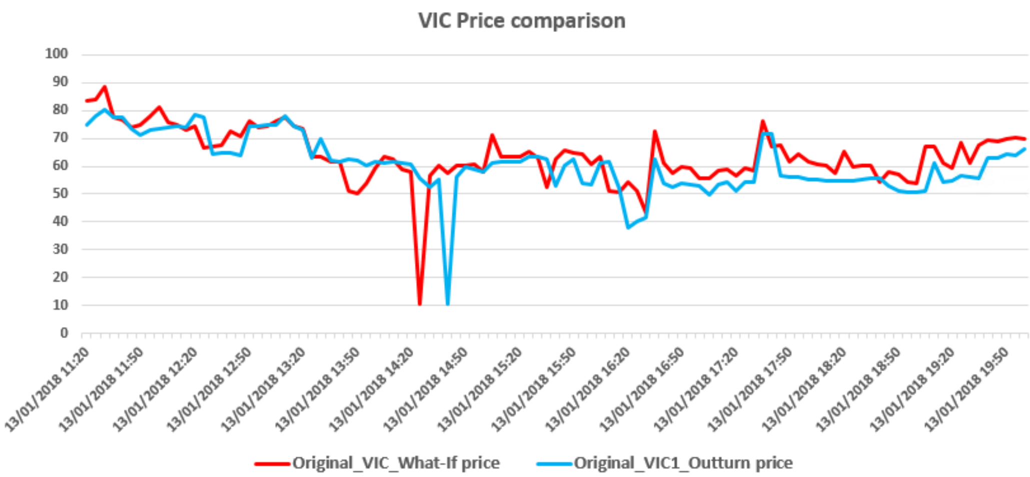


Figure 10 Comparison of VIC What-If price and Outturn price on 13 January 2018



An in-depth analysis of both events indicated that the anomalous price outcomes in NSW and QLD were a result of overly restrictive limits produced by some feedback constraint equations in the Pricing run. It was observed that the computation of the Right Hand Side (RHS) of feedback constraint equations in the Pricing run was based on a mixture of measured values (from SCADA) and What-If values (produced in previous DI of the Pricing run). Table 1 below provides a comparison of the current inputs for feedback constraint equations between the Outturn and Pricing runs.

Table 1 Comparison of feedback constraint equation inputs between Outturn and Pricing runs

Generic Constraint RHS term	Input for Outturn run	Input for Pricing Run
Rating	Defined Value	Defined Value
Scheduled gens/loads	Measured value	What-If value (from prev. DI target)
Semi-scheduled gens	Measured value	What-If value (from prev. DI target)
Interconnector flows	Measured value	What-If value (from prev. DI target)
Intra-regional flows	Measured value	Measured value

The use of measured values for intra-regional flows in computing the RHS of the feedback constraint equations produced overly restrictive limits for some network elements in the Pricing run. To prevent violation of these constraint equations in the Pricing run, consistent with the current Intervention Pricing Methodology, the National Electricity Market Dispatch Engine (NEMDE) constrained off the target flows north on the VIC-NSW and QNI interconnectors on 9 February 2017 and 13 January 2018 respectively. The assumed reduced flow north resulted in more expensive generation dispatched in NSW and QLD in the Pricing run, and higher prices in those regions.

4.2 Issue 2: Identification of tripped generators in the Intervention Pricing run

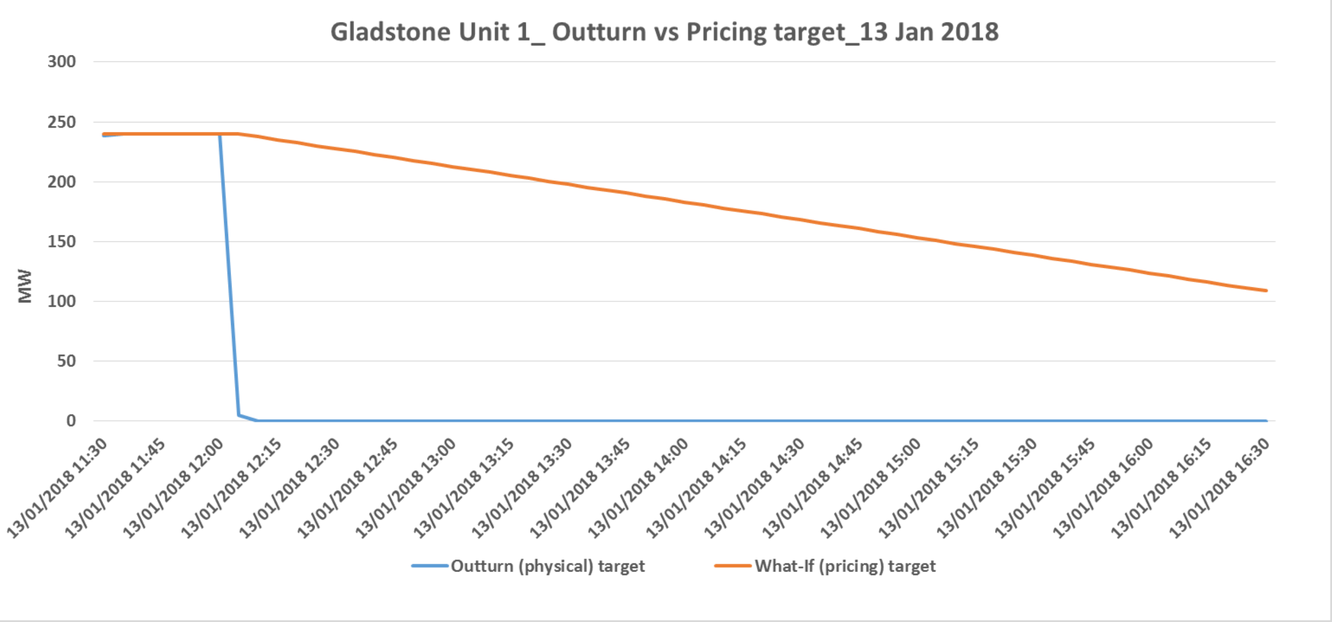
The Pricing run does not have the capability to identify generators that have tripped in the Outturn run. A key assumption in the existing Intervention Pricing Methodology involves setting the initial loading (at the beginning of each DI) for each generating unit in the Pricing run to the unit's What-if dispatch target calculated in the previous DI of the Pricing run.

Soon after a trip, the generating unit's initial loading in the Outturn run would reflect the reduced output due to the trip. The initial loading in the Pricing run would still reflect the output at the What-if target level prior to the trip. The only information available to NEMDE for the Pricing run to reflect the trip is the rebid submitted by the tripped generator indicating its reduced availability. Once the rebid is received, NEMDE will ramp down the tripped generator in accordance with its ramp down limits in the Pricing run. Generating units with slow ramp down rates, will take many hours for their output to reduce to 0 MW in the Pricing run.

An example of this issue occurred during the AEMO intervention event (SA direction) on 13 January 2018. At 1158 hrs on 13 January 2018, Gladstone power station (PS) Unit 1 tripped from 239 MW. For DI ending 1205 hrs, the initial loading for Gladstone PS Unit 1 in the Outturn run was 0 MW (consistent with the unit trip) whereas the initial loading in the Pricing run was 240 MW (target from DI ending 1200 hrs). A rebid indicating 0 MW availability for Gladstone PS Unit 1 was submitted at 1200 hrs. For DI ending 1210 hrs, the Outturn run indicated a dispatch target of 0 MW for Gladstone PS Unit 1 (consistent with the rebid and unit trip) whereas the Pricing run indicated a What-if target of 237.53 MW due to the low ramp down limits (0.5 MW/min) for Gladstone PS Unit 1. Because the trip could not be identified in the Pricing run, generation from Gladstone PS Unit 1 continued to be represented in the Pricing run for many hours (gradually reducing its output in accordance with ramp down limits).

Figure 11 below provides a comparison of the Outturn targets and What-if targets for Gladstone PS Unit 1 on 13 January 2018.

Figure 11 Comparison of the Outturn (physical) targets and What-If (pricing) targets for Gladstone PS Unit 1 on 13 January 2018



4.3 Issue 3: FCAS Trapped generators in the Pricing run

Generating units may become 'trapped' at the minimum or maximum enablement limits of their FCAS trapeziums in the Pricing run. Once this occurred, these units remain trapped for all subsequent DIs in the Pricing run until either the FCAS enablement limits are rebid or intervention pricing is revoked.

For the first DI when a generating unit gets trapped, the What-if target is the same as the minimum or maximum enablement limit (depending on which end of the FCAS trapezium the generating unit is trapped). Due to the assumption in the existing Intervention Pricing Methodology whereby the What-if target from the previous DI is set as the initial loading for the next DI, the generating unit continues to be trapped, since the initial loading remains at the minimum or maximum enablement limit. The trapped state thus perpetuates for all subsequent intervals (after the first DI) until the minimum or maximum enablement limits are rebid by the Generator or intervention pricing is revoked.

This issue does not occur in the Outturn run since a Generator can alter its actual output (initial loading) to un-trap it from the FCAS trapezium, without having to rebid its FCAS enablement limits.

An example of this issue was highlighted during an AEMO intervention event (SA direction) on 2 September 2017:

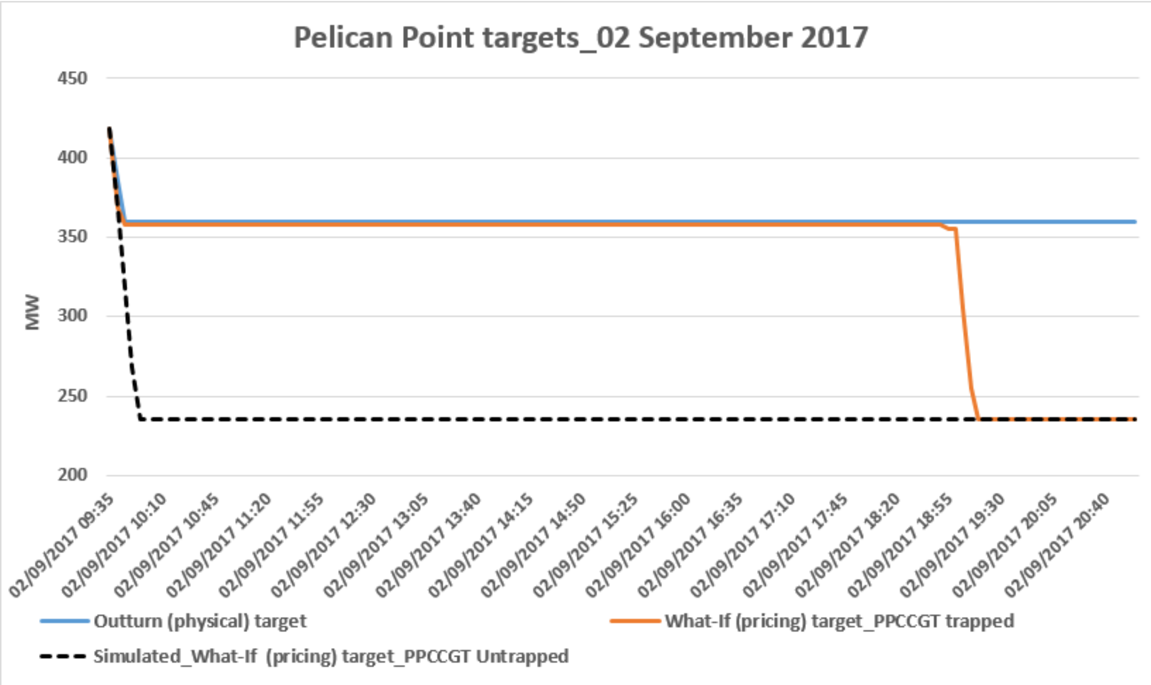
At 0930 hrs on 2 September 2017, AEMO issued a direction to Pelican Point GT12 to remain synchronised and follow dispatch targets. Prior to the direction, both Pelican Point units GT11 and GT12 were available to generate. Engie intended to de-commit Pelican Point GT12 from 0930 hrs (as indicated by the rebid for Pelican Point at 1353 hrs on 1 September 2017). To meet the system strength requirements in SA, AEMO directed Pelican Point GT12 to remain synchronised and follow dispatch targets.

To reflect the direction in the Outturn run, AEMO invoked a direction constraint whereby total Pelican Point output would equal 360 MW (combined output from GT11, GT12 and Steam Turbine). In the Pricing run, a pricing constraint was invoked to limit total Pelican Point output to less than or equal to 235 MW (combined output from GT11 and Steam Turbine). When intervention pricing was triggered at DI ending 0935 hrs, Pelican Point output in the Pricing run began to reduce from 468 MW (output prior to Direction) in accordance with its ramp down rate (9.97 MW/min). By DI ending 0940 hrs, Pelican Point output had reduced to 368.33 MW.

For DI ending 0945 hrs, when Pelican Point output was ramping down below the minimum enablement limit (358 MW) of its Raise and Lower FCAS trapeziums, the What-if target was trapped at the minimum enablement limit of 358 MW. The What-if target from DI ending 0945 hrs was set as the initial loading for DI ending 0950 hrs. As a result, Pelican Point continued to be trapped for DI ending 0950 hrs. The issue perpetuated until DI ending 1855 hrs when Engie rebid the minimum enablement limits of the FCAS trapeziums, thus un-trapping Pelican Point in the Pricing run.

Figure 12 below compares Pelican Point targets from the Outturn and Pricing run (with Pelican Point trapped) on 2 September 2017 to a simulated Pricing run (with Pelican Point un-trapped).

Figure 12 Comparison of Pelican Point targets from the Outturn and Pricing run on 2 September 2017 (Pelican Point trapped) and simulated run (Pelican Point un-trapped).



4.4 Issue 4: Generators with zero MW/min ramp rates

A few Generators have historically submitted ramp up/down rates of 0 MW/min by default in dispatch, under legacy arrangements. These include Yarwun (non-scheduled, QLD) and Lake Echo and Tarralea (scheduled, TAS).

Generating units with 0 MW/min ramp rates would always be dispatched at their Initial MW in the Outturn run and What-If Initial MW in the Pricing run, due to the high constraint violation penalty (CVP) factor for ramp rates.

In the Pricing run, however, these units will be dispatched for all intervals at the same level as the What-If Initial MW in the first DI.

For the first DI of the Pricing run, these units will reflect the same value for Initial MW and What-If Initial MW, based on the metered SCADA output. For the second DI of the Pricing run, the InitialMW will reflect the updated metered SCADA output whereas What-If Initial MW will reflect the What-if dispatch target calculated in the previous DI of the Pricing run.

I.e. What-If InitialMW$_{\mathbf{DI\ 2}}$ = What-If target $_{\mathbf{DI\ 1}}$ (= What-If InitialMW $_{\mathbf{DI\ 1}}$).

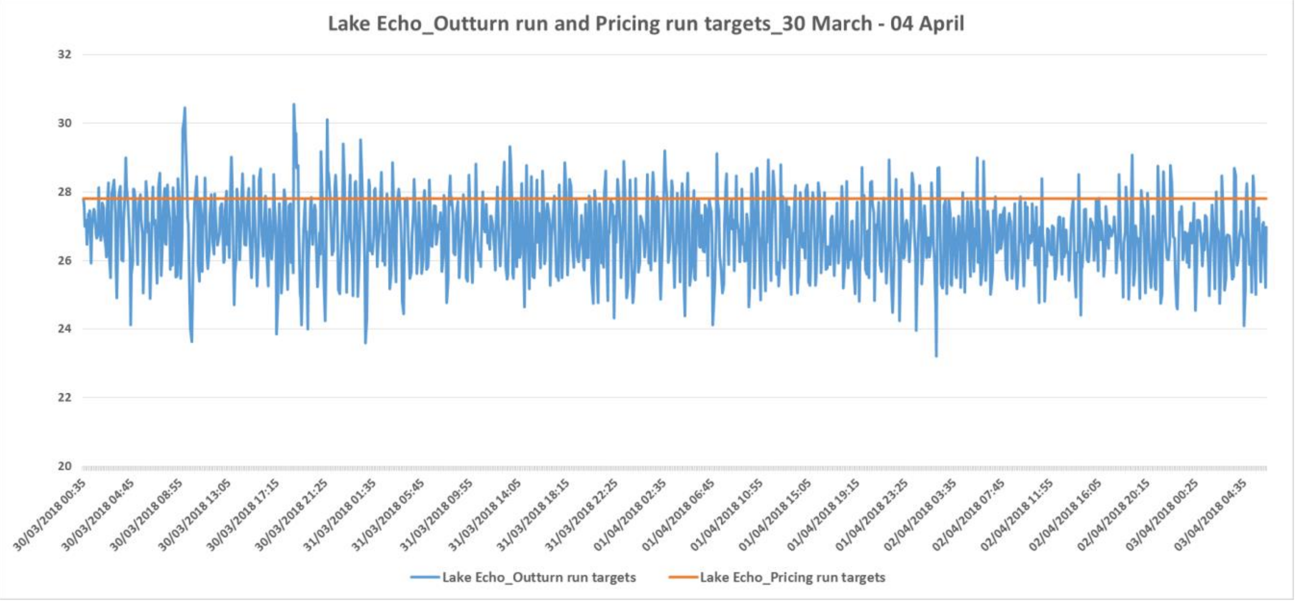
Due to the 0 MW/min ramp rate, the What-if dispatch target (Pricing run) in the second DI will reflect the What-If Initial MW (which is the same value as What-If Initial MW from previous DI).

➔ What-If target $_{\mathbf{DI\ 2}}$ = What-If Initial MW $_{\mathbf{DI\ 2}}$ (= What-If target $_{\mathbf{DI\ 1}}$ = What-If InitialMW $_{\mathbf{DI\ 1}}$).

The What-If Initial MW value from the first DI gets applied as the target for all subsequent intervals in the Pricing run due to the 0 MW/min ramp rates.

Figure 13 below compares the Lake Echo targets between Outturn run and Pricing run during the 30 March-03 April 2018 Intervention Event. As seen below, the targets in the Pricing run indicate a flat-line along the What-If Initial MW in the first DI.

Figure 13 Lake Echo targets between Outturn run and Pricing run during the 30 March-03 April 2018 Intervention Event



5. PROPOSED CHANGES TO THE INTERVENTION PRICING METHODOLOGY

To address the issues detailed in Section 4, AEMO believes that a review of the Intervention Pricing methodology is warranted to ensure that it better meets the objective of the Intervention Pricing Methodology under NER clause 3.9.3(b).

The following sections outline the proposed changes to the Intervention Pricing Methodology to address these issues.

5.1 Issue 1: Inconsistent inputs to feedback constraints in Pricing run

AEMO discussed a number of options to resolve this issue with the IPWG. The most promising option proposed setting the RHS of feedback constraint equations to be equal between the Outturn and Pricing runs, effectively ensuring a consistent technical envelope between the two runs. Table 2 below presents the proposed change in inputs for feedback constraint equations for the Pricing Run.

Table 2 Proposed solution for feedback constraint inputs in pricing run

Generic Constraint RHS term	Input for Outturn run	Input for Pricing Run
Rating	Defined Value	Defined Value
Scheduled gens/loads	Measured value	~~What-If value (from prev. DI target)~~ Measured value
Semi-scheduled gens	Measured value	~~What-If value (from prev. DI target)~~ Measured value
Interconnector flows	Measured value	~~What-If value (from prev. DI target)~~ Measured value
Intra-regional flows	Measured value	Measured value

The proposed changes would affect the RHS of feedback constraint equations only (i.e. the technical envelope), the targets for generating units and interconnectors in the pricing run will continue to be based on their bids, ramp rates, and the targets from the previous DI of the Pricing run.

5.1.1 Reasoning for the proposed solution

The purpose of a constraint equation is to manage the flow across a network element within its limits (rating or stability limits). The RHS of the constraint equation reflects the limit across the network element. This limit can be calculated as a function of regional load, line flows (inter-regional or intra-regional), and generator operating points. Although the computation of network limits in the central dispatch process involves generator operating points, this is an artefact of the constraint development process and the limits being represented are independent of generator operating points. The technical envelope for a network element between the Outturn and Pricing runs should be the same, and hence the RHS of the constraint equations reflecting the network limits can be kept the same.

For a more detailed mathematical explanation of the reasoning, please refer to Slides 31-40 of IPWG Meeting #4 Presentation Slides[3] or Pages 6-10 of 'IPWG F2F – Draft Minutes – 20180322.pdf'[4] document.

[3] Slides are available within the meeting pack for IPWG Meeting 4 published on AEMO Website: https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

[4] IPWG F2F – Draft Minutes – 20180322.pdf document is available within the meeting pack for IPWG Meeting 5 published on AEMO Website: https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

The proposed solution involves setting the RHS to be the same between the Outturn and Pricing runs only for thermal feedback and stability (transient or voltage) feedback constraint equations. Other generic constraints which are market-related (e.g. negative residue management, non-physical losses, non-conformance, MNSP Rate-of-change constraints) and FCAS constraints will continue to be determined dynamically, i.e. the RHS in each DI for these constraint equations would be determined based on the generator or interconnector target outcomes in the previous DI of the pricing run. This is because these constraint equations are not reflective of a network limit, but are used to manage market outcomes or FCAS requirements - both of which should remain dependent on generator and interconnector operating points in the Pricing run. Table 3 below outlines the proposed approach for each generic constraint type in the Pricing run.

Table 3 Proposed approach in the Pricing run for each generic constraint type

Constraint Type	Constraint Description	Proposed Approach
FCAS	FCAS Requirement Constraints	Dynamic (RHS calculated as per outcomes in Pricing run)
Ramping	Network ramping Constraints	Dynamic (RHS calculated as per outcomes in Pricing run)
NC	Non-conformance Constraints	Dynamic (RHS calculated as per outcomes in Pricing run)
NRM	Negative Residue Management Constraints	Dynamic (RHS calculated as per outcomes in Pricing run)
NSA	Network Support Agreement Constraints	Dynamic (RHS calculated as per outcomes in Pricing run)
Fixed Loading	Unit fixed loading Constraints	Dynamic (RHS calculated as per outcomes in Pricing run)
ROC	Rate of Change (ROC) Constraints	Dynamic (RHS calculated as per outcomes in Pricing run)
System Normal	Feedback Constraints	Static (RHS calculated same as Outturn run)
	Non-feedback Constraints	Dynamic (RHS calculated as per outcomes in Pricing run)
Network Outage	Feedback Constraints	Static (RHS calculated same as Outturn run)
	Non-feedback Constraints	Dynamic (RHS calculated as per outcomes in Pricing run)

5.1.2 Feasibility Study

To assess the feasibility of the proposed solution, AEMO applied the proposed solution to a range of historical cases where intervention pricing was in place.

Historical Cases

AEMO applied the proposed solution to 20 historical intervention events between February 2017 and March 2018 (approximately 10,000 DIs). The cases included the 9 February 2017 and 13 January 2018 intervention periods when anomalous prices were observed in regions that were not subject to a direction.

Assessment of outcomes

AEMO's assessment indicated that the proposed approach yields substantial improvements over the current approach.

AEMO assessed the study results by considering the impact on pricing outcomes, and confirming that:

- Pricing/flow outcomes were improved for the 9 February 2017 and 13 January 2018 cases, which previously showed abnormal prices resulting from feedback constraint issues.

Appendix A provides a comparison of the Outturn prices and What-If prices on 9 February 2017 and 13 January 2018 to Simulated What-If prices (using the proposed approach).

- No new extreme or unexplained price deviations were observed in other cases, which were previously well behaved.
- Simulated What-If prices were generally still higher than Outturn prices for most DIs (because the Outturn run includes additional energy supplied by the directed generators).
- The Simulated What-if prices in other cases did not deviate by a large margin as compared to the original What-If price or the Outturn price.

For a detailed assessment of the price outcomes from the feasibility study, please refer to the IPWG Feasibility Study paper[5].

AEMO is satisfied with the study results on the basis of all above criteria.

IPWG indicated strong support for the proposed approach based on the study outcomes.

Question for Consultation

1. Do participants agree with the proposed approach?
2. Are there issues that may not have been considered in the proposed approach?

5.2 Issue 2: Identification of tripped generating units in Pricing run

AEMO, after consultation with the IPWG, proposes the following check to be added into the NEMDE Caseloader to identify tripped generators in the Pricing run:

For all generators in each DI:

IF *[Bid Availability < (What-If Initial MW - 2 x ROC down/DI)* ***AND*** *InitialMW < (What-If Initial MW - 2 x ROC down/DI)]*

THEN *What-If Initial MW = Initial MW.*
ELSE *What-If Initial MW = What-If Initial MW (no change).*

5.2.1 Reasoning for the proposed solution

A generating unit trip may involve a partial trip (output reduces well below bid availability but above 0 MW) or a full trip (output reduces to 0 MW). For either scenario, the Generator would rebid its availability to the reduced output level.

A reduced bid availability and reduced actual output (Initial MW) in the Outturn run would indicate a partial or full trip. Accordingly, a generating unit with bid availability **and** Initial MW less than the What-If Initial MW by an amount exceeding twice the rate of change down rate will be treated as a tripped generating unit, i.e. the unit's What-If Initial MW will be set equal to Initial MW in the Pricing run.

Question for Consultation

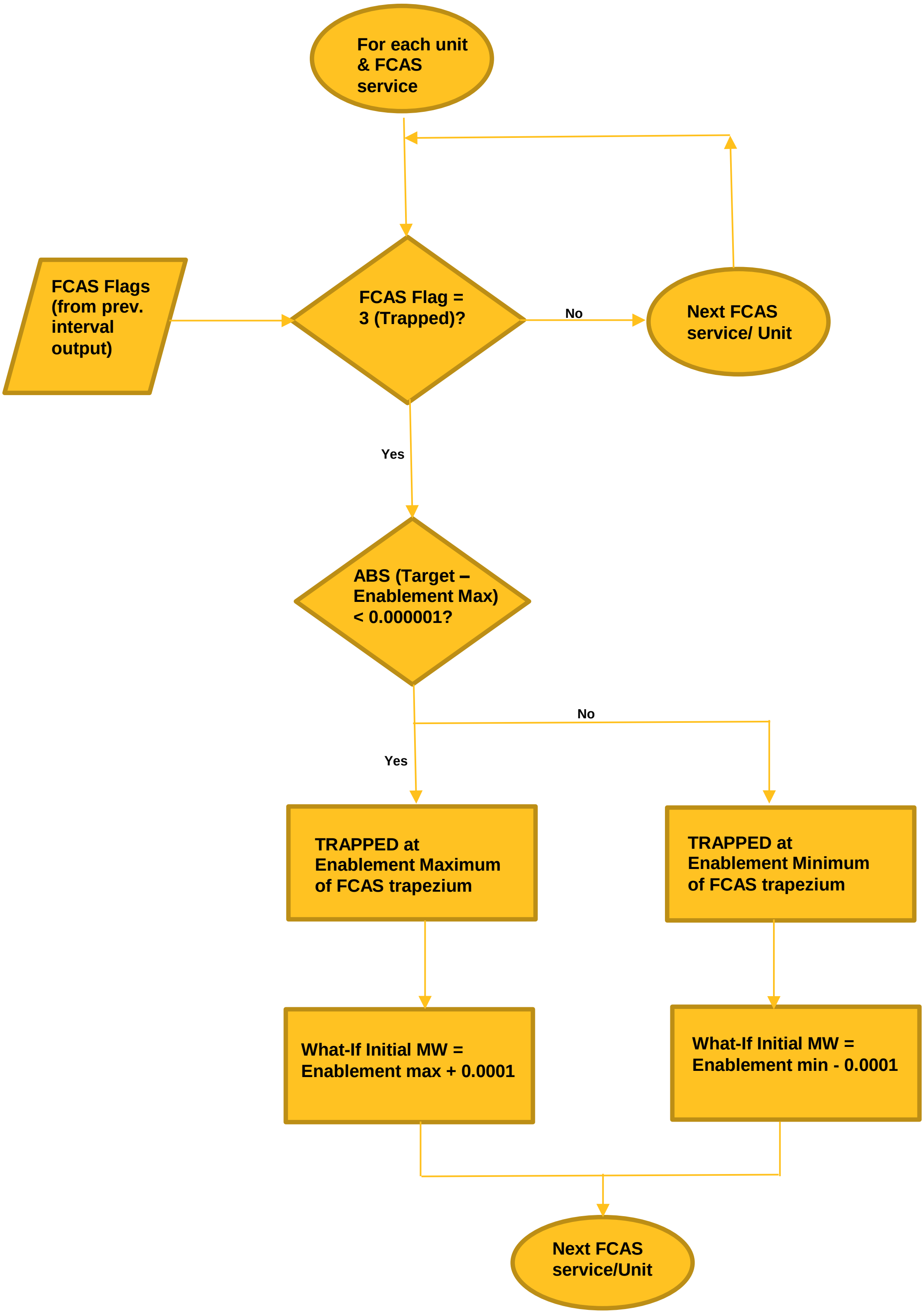
1. Do participants agree with the proposed approach?
2. Are there issues that may not have been considered in the proposed approach?

[5] IPWG Feasibility study paper is included in IPWG Meeting 5 – Meeting Pack available here: https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

5.3 Issue 3: FCAS Trapped generators in the Pricing run

AEMO, after consultation with the IPWG, proposes the following logic (shown in Figure 14) to be added into the NEMDE Caseloader to un-trap generating units trapped in the FCAS trapeziums of the Pricing run.

Figure 14 FCAS trapezium Untrapping logic in Pricing run



5.3.1 Reasoning for the proposed solution

Generating units may be trapped at the enablement maximum or enablement minimum of their FCAS trapeziums. The proposed logic involves checking whether a unit is trapped at either end of its FCAS trapezium and if so, amending the What-If Initial MW (unit output in the Pricing run) by a small amount to move the unit's What-If output outside the trapezium (thus un-trapping the unit).

Question for Consultation

1. Do participants agree with the proposed approach?
2. Are there issues that may not have been considered in the proposed approach?

5.4 Issue 4: Generators with zero MW/min ramp rates

For generating units with default 0 MW/min ramp rates on an ongoing basis, AEMO proposes to set the What-If Initial MW to be equal to their Initial MW for all intervals in the Pricing run.

5.4.1 Reasoning for the proposed solution

The dispatch of these generating units should be consistent between the Outturn and Pricing runs (which does not currently occur). This could be achieved by ensuring their What-If Initial MW is equal to their Initial MW for all intervals in the Pricing run.

Question for Consultation

1. Do participants agree with the proposed approach?
2. Are there issues that may not have been considered in the proposed approach?

6. CONCLUSION

Under NER 3.9.3(e), AEMO is required to develop a methodology in accordance with Rules consultation procedures to determine the dispatch prices and ancillary service prices that AEMO reasonably considers would have applied had an AEMO intervention event not occurred.

AEMO identified issues with the existing Intervention Pricing Methodology during the course of various Direction events in 2017. AEMO established the Intervention Pricing Working Group (IPWG) to seek industry feedback on the issues (outlined in Section 4) with the existing methodology. During the course of the five meetings, AEMO & IPWG agreed on the proposed solutions (outlined in Section 5) to resolve these issues.

AEMO is seeking confirmation/feedback from stakeholders in relation to the appropriateness of the proposed solutions and the associated changes to the Intervention Pricing Methodology.

In accordance with the proposed consultation timetable in Section 1, AEMO invites stakeholder feedback by 06 August 2018 to Michael.Sanders@aemo.com.au.

For any further enquiries, feel free to contact Michael Sanders at Michael.Sanders@aemo.com.au.

APPENDIX A. COMPARISON OF WHAT-IF PRICES (CURRENT APPROACH) AND SIMULATED WHAT-IF PRICES (PROPOSED APPROACH)

A.1 9 February 2017

Figure 15 Comparison of NSW What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)

Figure 16 Comparison of QLD What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)

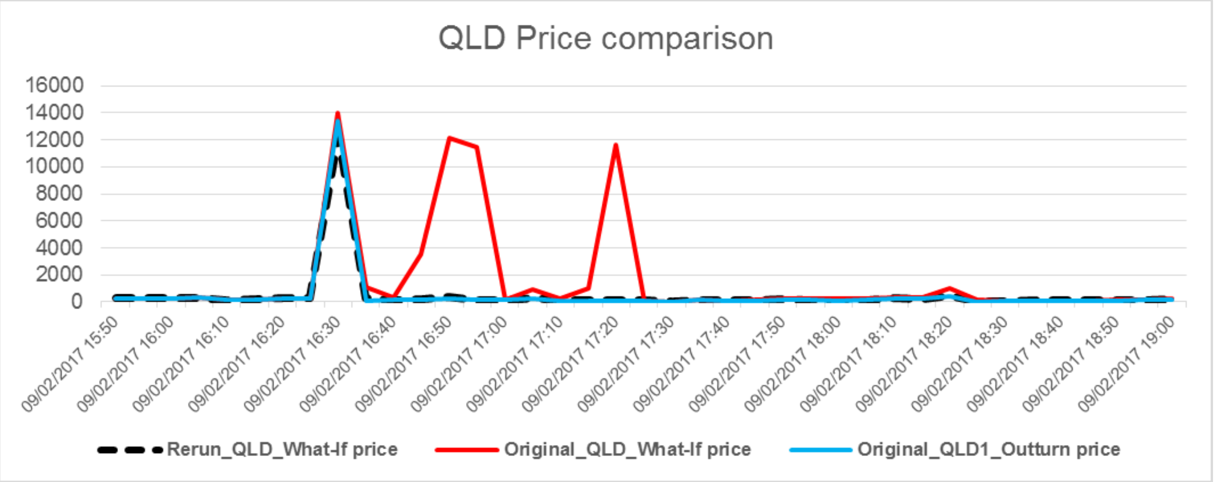


Figure 17 Comparison of SA What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)

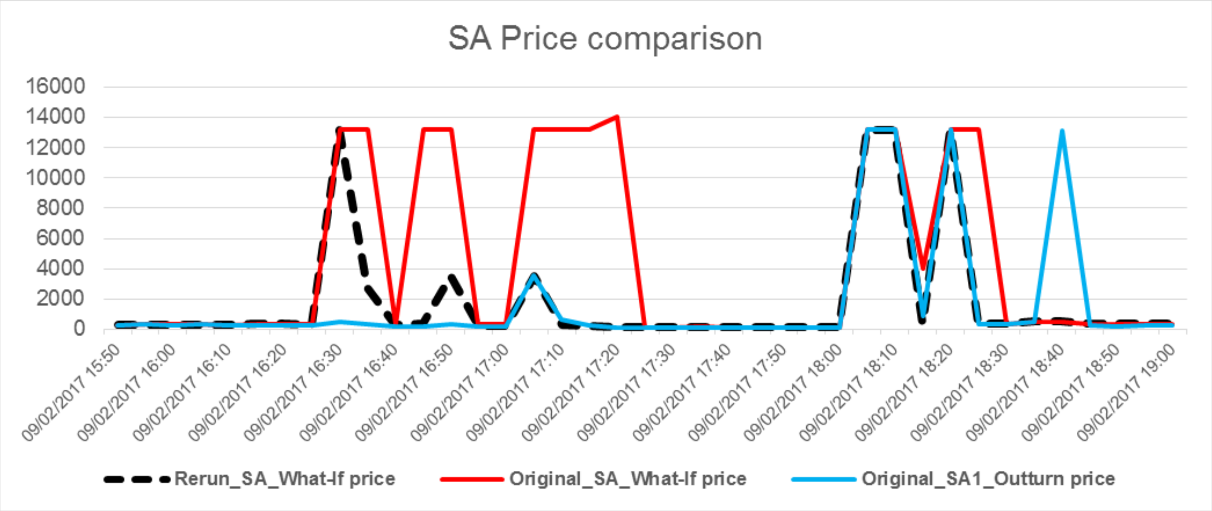


Figure 18 Comparison of TAS What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)

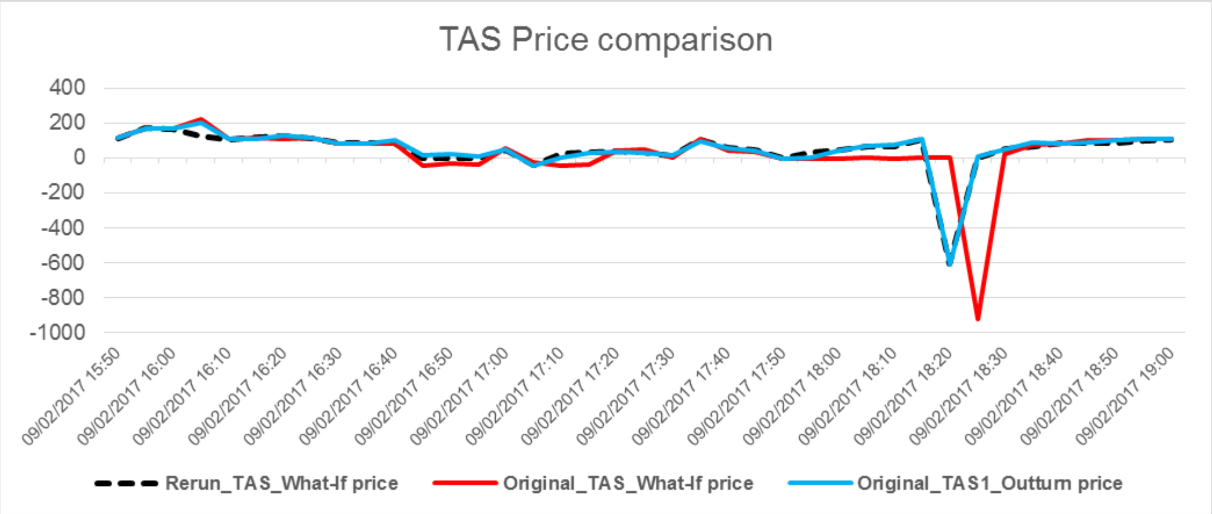
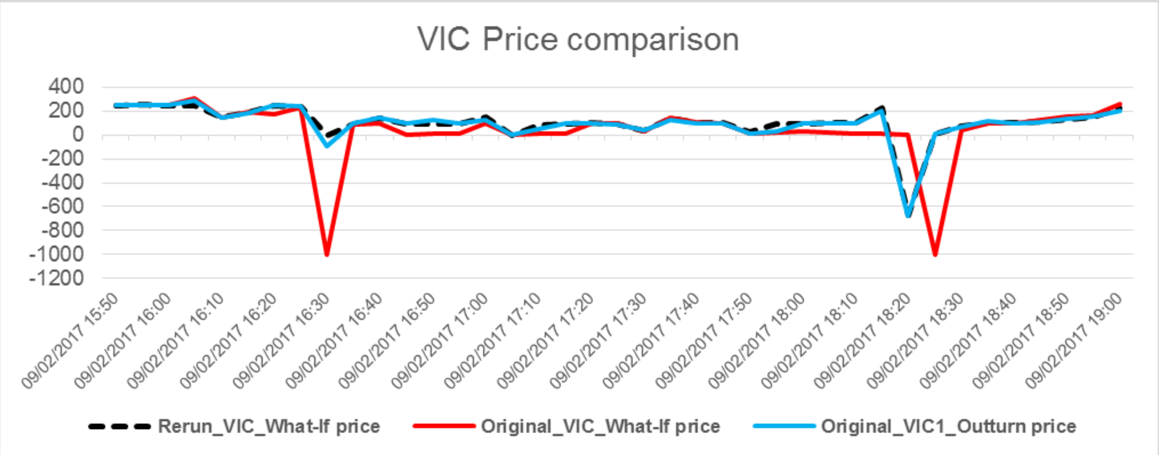


Figure 19 Comparison of VIC What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)



A.2 13 January 2018

Figure 20 Comparison of NSW What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)

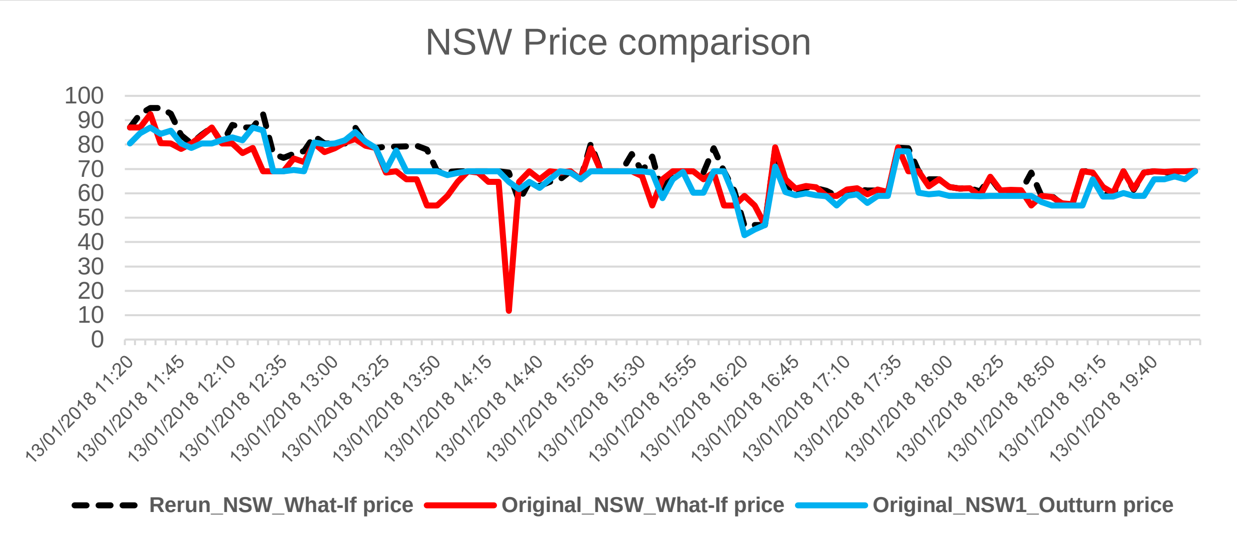


Figure 21 Comparison of QLD What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)

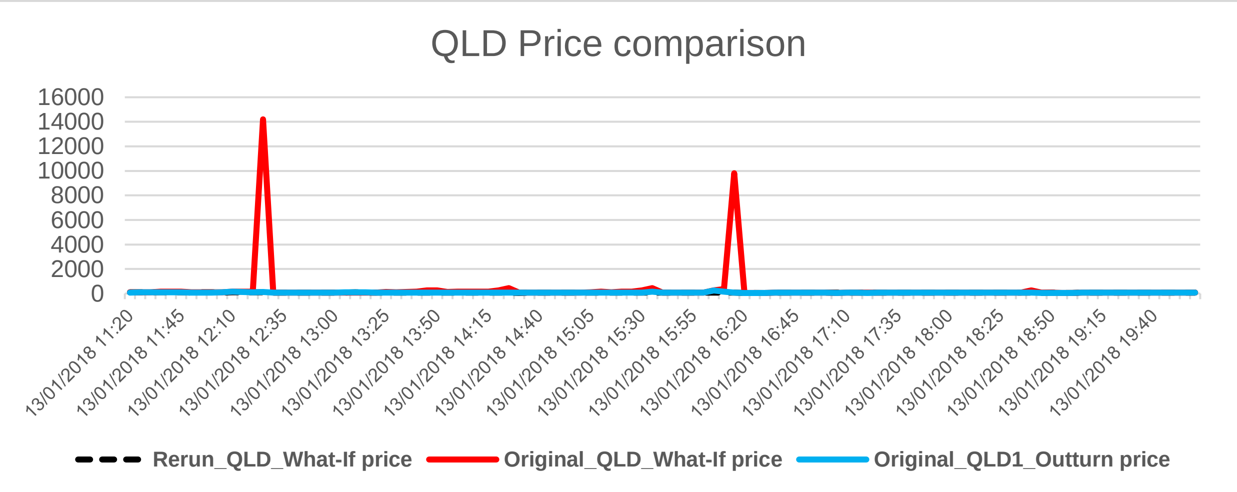


Figure 22 Comparison of SA What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)

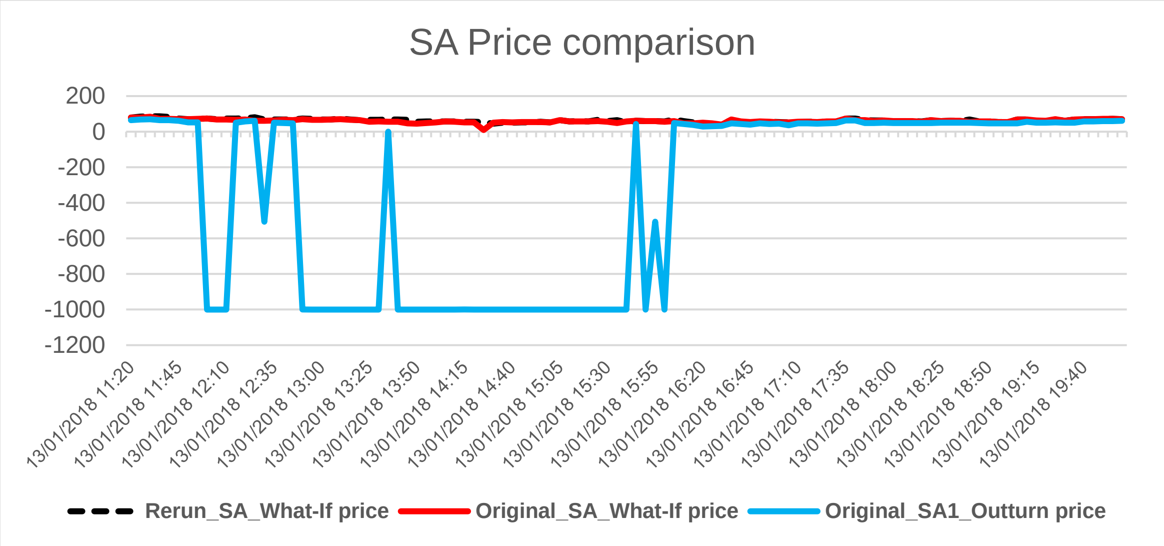


Figure 23 Comparison of TAS What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)

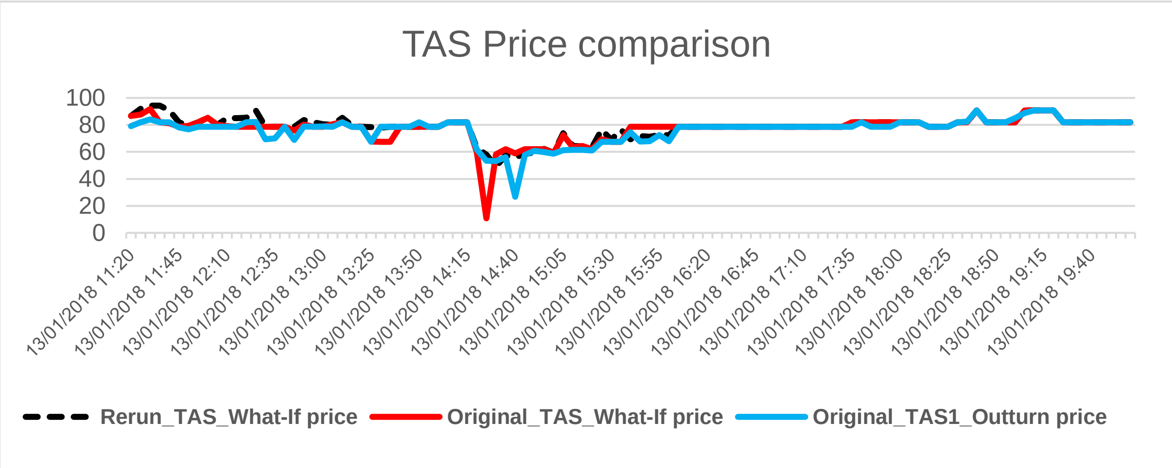
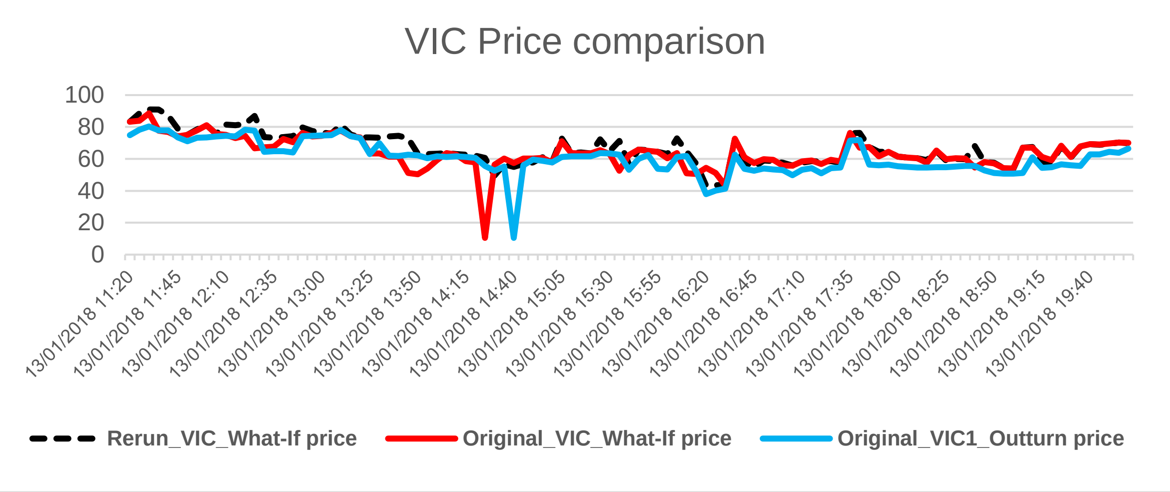


Figure 24 Comparison of VIC What-If price (*Original_What-If price*) and Outturn price (*Original_Outturn price*) to Simulated What-If price (*Rerun_What-If price*)



ABBREVIATIONS

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
DI	Dispatch Interval
FCAS	Frequency Control Ancillary Services
MNSP	Market Network Service Provider
NEM	National Electricity Market
NER	National Electricity Rules
NSW	New South Wales
QLD	Queensland
SA	South Australia
TAS	Tasmania
TI	Trading Interval
VIC	Victoria