NEM SCHEDULING ERROR AND ISSUES

1 MAY 2015 – KEMPS CREEK TRANSFORMER DERATING

Published: **August 2015**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about an incident in the NEM on 1 May 2015, using the information available as at the date of publication.

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EXECUTIVE SUMMARY

This incident report has been produced in response to interest from participants to large price movements in New South Wales, Victoria and Tasmania on 1 May 2015. These movements were linked with preparation for a planned maintenance outage of the Kemps Creek No.3 500/330kV transformer in New South Wales.

AEMO has concluded that a scheduling error occurred because AEMO failed to follow the central dispatch process by not invoking constraint sets from the original outage time that would adequately represent the physical parameters of the power system during the outage. The focus of this report is on the scheduling error, however the report also covers additional processes that were involved in power system operation before and during the incident, which were outside the scope of AEMO's previously published Pricing Event Report[1].

On 30 April 2015, TransGrid submitted a protection outage request for maintenance work on the Kemps Creek No.3 500/330kV transformer cooling system to commence at 0715hrs on 1 May. While the transformer would remain in service, it would be de-rated.

TransGrid incorrectly entered the outage request into the Network Outage Scheduler (NOS) as an 'in-service' outage and AEMO did not detect the error. Later that day, AEMO performed an outage assessment and incorrectly determined that the post-contingent flow across the Kemps Creek transformers would not exceed the ratings during the outage. As a result, no constraint set was invoked to manage the outage.

AEMO entered the transformer de-rating in the Energy Management System (EMS) just before the revised planned outage start time at 0800 hrs. At this time, AEMO's network applications indicated that the ratings would be exceeded following the loss of the Kemps Creek No.2 500/330KV transformer, and outage constraint sets would need to be invoked to maintain power system security.

AEMO, in discussion with TransGrid, delayed the outage to 0900 hrs to create a constraint set to manage the outage and allow constraint ramping.

AEMO has assessed that market outcomes would have been similar without the scheduling error, with potential reductions in Queensland spot prices, subject to generator rebidding.

[1] Available at http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports/May-2015.

CONTENTS

TABLES

FIGURES

1. INTRODUCTION

This report reviews an incident where planned maintenance of Kemps Creek No. 3 500/330kV transformer resulted in unusual pricing outcomes on 1 May 2015. The incident led to relatively high spot prices in New South Wales (NSW) and Victoria (VIC), negative spot prices in Tasmania (TAS) and high Frequency Control Ancillary Service (FCAS) prices in TAS.

AEMO published a pricing event report for this incident on its website in May 2015[2].

AEMO has received a number of enquiries from participants that were outside the scope of the pricing event report, and this incident report addresses those enquiries that primarily concerned the operational processes involved before and during the event.

AEMO has investigated this incident to determine whether AEMO's operation of the market and power system was appropriate, and make improvements where possible.

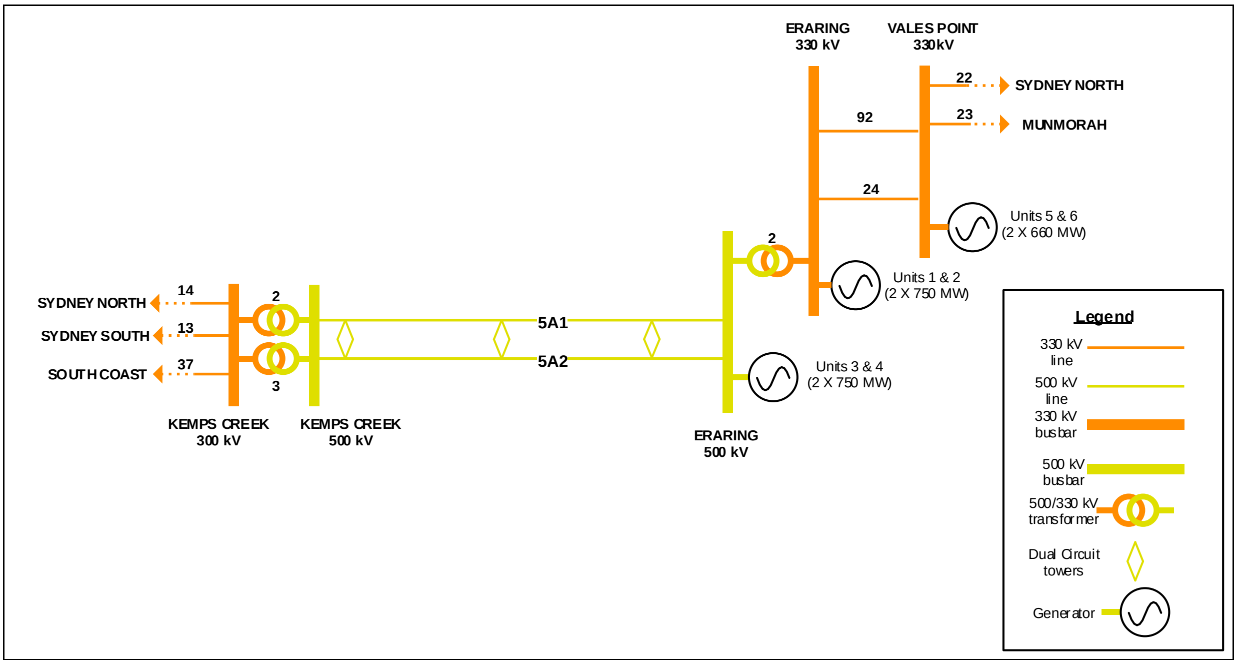
[2] See http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports/May-2015)

2. RULE, SYSTEM AND PROCESS CONSIDERATIONS

2.1 Kemps Creek Substation

Kemps Creek is located about 39km west of Sydney CBD. The parallel 500kV lines between Kemps Creek and Eraring substations normally transfer power from northern NSW power stations, primarily from Eraring, to Sydney loads. Kemps Creek substation has two 500/330kV transformers (No.2 and No.3 transformers). Eraring substation has one 500/330kV transformer (No.2 tie transformer). Figure 1 provides a network diagram for the Kemps Creek transformers and the connecting network.

Figure 1 Network Diagram



2.2 Processes for managing network outages

AEMO maintains procedures and guidelines that carry out National Electricity Rules (NER) requirements related to outages. The relevant AEMO documents for this outage are:

- SO_OP_3718 Outage Assessment, which describes procedures for submitting and assessing outage requests.
- SO_OP_3715 Power System Security Guidelines, which describes preparatory procedures for outages and permission to proceed.
- SO_OP_3705 Dispatch, which describes procedures for applying network constraint ramping.
- Constraint Formulation Guidelines[3], which among other things include the processes by which AEMO will identify or be advised of the requirement to create or modify a constraint equation and to be used by AEMO for applying, invoking and revoking a constraint set.

[3] Refer clause 3.8.10 of the NER.

2.3 Process for network constraint ramping

In 5-minute Dispatch, AEMO applies ramping to all planned network outage constraint sets with interconnectors and generation on the left-hand-side (LHS). Ramping is a process that gradually changes network flows affected by the outage towards their post-contingent outage transfer limits to maintain system security and minimise market impact. It occurs before AEMO allows a planned outage to go ahead.

The Network Constraint Ramping process is described in detail in Appendix A.

2.4 Determining scheduling errors in the NEM

A scheduling error is any one of the following circumstances[4]:

- AEMO declares, or the dispute resolution panel determines, that AEMO has failed to follow the central dispatch process set out in rule 3.8 of the NER.
- AEMO determines under clause 3.9.2B(d) that a dispatch interval (DI) contained a manifestly incorrect input.

Failure to follow the central dispatch process

For this event, the relevant parts of rule 3.8 are:

- Clause 3.8.1(b) paragraphs (4) and (5), which require that central dispatch is subject to power system security requirements and network constraints.
- Clause 3.8.10, which requires AEMO to develop and comply with the network constraint formulation guidelines.[5]

Manifestly incorrect inputs

The procedures for manifestly incorrect inputs require that a DI must be identified as subject to review by the automated procedure referred to in clause 3.9.2B(h) before it can be considered a scheduling error.

[4] Refer clause 3.8.24 of the NER.
[5] AEMO. *Constraint Formulation Guidelines*. 6 July 2010. http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Guides-and-Descriptions/Constraint-Formulation-Guidelines

3. EVENT DETAILS RELATING TO THE OUTAGE

The following sections summarise the events relating to the outage and subsequent market outcomes, with further details provided in Appendix B.

3.1 Outage submission

At approximately 1406 hrs on Thursday 30 April 2015, TransGrid submitted via the NOS a protection outage associated with the Kemps Creek No.3 500/330kV transformer. The outage was to commence at 0715 hrs on Friday 1 May 2015. This outage was for work on the transformer cooling system and was entered in NOS as an 'in-service' outage[6]. TransGrid advised that while the transformer would remain in service, it would be de-rated to 600 Mega-volt-ampere (MVA) during this work[7]. TransGrid also advised that it did not expect the load on the transformer to exceed 600 MVA during the work. The outage start time was changed to 0800 hrs later.

3.2 Outage assessment

3.2.1 30 April 2015

On the evening of Thursday 30 April 2015, AEMO assessed the outage and determined that the post-contingent flow across the Kemps Creek No.3 transformer would not exceed 600 MVA during the outage. AEMO does not have a constraint set in its constraint library for this type of outage. On the basis that AEMO assessed that the flows would not exceed 600 MVA, no action was taken to invoke an outage constraint set.

3.2.2 1 May 2015

When AEMO entered the revised ratings into the Energy Management System (EMS) just before the planned outage start time, it became apparent through AEMO's network applications that the Kemps Creek No.3 500/330KV transformer rating would be exceeded following the loss of the other transformer, and constraint equations would be needed to cater for the planned outage. AEMO, following discussion with TransGrid, delayed the outage to 0900 hrs on Friday 1 May to create constraint equations to manage the outage and allow prior ramping.

3.3 Constraint and market outcomes

In response to the potential violation indicated by the AEMO's network applications[8], AEMO used its Constraint Automation (CA) tool to create a constraint set. Constraint set CA_SPS_445534C8[9] was invoked at approximately 0806 hrs with a start time of 0900 hrs to allow 30-minute Pre-dispatch to run with the constraint set invoked and, based on the Pre-dispatch results, create ramping constraint sets to ramp to the final outage level. At 0832 hrs, shortly after the 0900 hrs 30-minute Pre-dispatch run[10], AEMO

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[6] In-service outage is defined in section 9.2.5 of the outage assessment procedure SO_OP_3718 (http://www.aemo.com.au/Electricity/Policies-and-Procedures/System-Operating-Procedures/Outage-Assessment-SO_OP_3718). The correctness of the action on 30 April 2015 is analysed in section 4.1.

[7] Standard normal rating is 1200MVA and post-contingent rating is 1638MVA.

[8] Discussed in 3.2.2.

[9] See Appendix C.1 for a description

[10] 0900 hrs 30-minute Pre-dispatch run occurs at 0830 hrs. Its first trading interval ends at 0900 hrs.

invoked the ramping constraint set. Market Notice 48836 was issued at 0845hrs to advise the market that the CA constraint sets had been invoked.

Shortly after the outage constraint set was invoked, AEMO noted that 5-minute Pre-dispatch was showing large price movements in NSW. A number of participants contacted AEMO seeking to understand this outcome. These price movements were not evident in the 0900hrs 30-minute Pre-dispatch outcomes (published at 0830hrs).

At this time AEMO checked the suitability of the constraint set developed by the CA tool. Analysis showed the constraint set accorded with Constraint Formulation Guidelines.

Appendix D discusses the outage and ramping constraint sets in detail.

Appendix E analyses the market conditions and outcomes, including rebidding.

4. DETERMINING THE SCHEDULING ERROR AND MARKET IMPACT

4.1 Outage assessment

AEMO has reviewed the outage assessment it performed on 30 April 2015 and determined that it was incorrect.

The case used for outage assessment on 30 April 2015 indicated an overload of Kemps Creek No.3 transformer for the contingent loss of the Kemps Creek No.2 transformer or the contingent loss of Eraring No.2 tie transformer. AEMO overlooked this overload and therefore considered that a constraint set was not required to manage security during the outage.

Had the outage been assessed correctly and an outage constraint set been attached to the NOS on 30 April 2015, the outage information would have been published via the NOS on 30 April 2015. This would have given early notice to the market.

AEMO has reviewed its procedures for outage assessment and determined they are adequate. AEMO has addressed the incorrect outage assessment with relevant staff. AEMO will make necessary changes to its staff training.

4.2 Scheduling error determination

Under NER clause 3.8.24 (a)(2), a scheduling error occurs when AEMO determines that it has failed to follow the central dispatch process set out in rule 3.8.

In this case, AEMO has determined that its procedures for invoking constraint sets that adequately represent the physical parameters of the power system during the outage were not correctly followed when the outage assessment was performed on 30 April 2015. AEMO declares that a scheduling error has occurred for 19 DIs on 1 May 2015, from DI ending 0730 hrs to DI ending 0900 hrs. This relates the period that AEMO did not invoke ramping and outage constraint sets in relation to the original outage start time of 0800 hrs[11].

4.3 Market impact

AEMO's EMS and MMS has a limitation to process short notice temporary rating changes. This limitation is discussed further in section 5.2. Current practice is to change the rating in EMS just before the outage start time.

Had the outage been assessed correctly by AEMO and the CA constraint set been invoked on 30 April 2015, the constraint ramping on 1 May 2015 would have been based on the 30-minute Pre-dispatch results, calculated using the incorrect rating of 1638 MVA as opposed to the correct rating of 600MVA. Based on the rating of 1638MVA, 30-minute Pre-dispatch would have calculated the right-hand-side (RHS) of the constraint equations CA_SPS_445534C8_01 and CA_SPS_445534C8_02 as 3978 and 3300 respectively. These RHS values are less conservative than the initial flow levels of 2308.30 and 1354.85. Therefore, no effective constraint ramping would have occurred before the scheduled outage start time at 0800 hrs.

Under this scenario, the real-time contingency analysis application would have indicated a post-contingent overload on the Kemps Creek No.3 transformer on loss of No.2 transformer only when the No.3 transformer rating was changed to 600 MVA in the EMS just before 0800 hrs. AEMO would have

[11] Had the outage assessed correctly, a ramping constraint set would have been invoked from DI ending 0730 hrs to DI ending 0800 hrs and an outage constraint set would have been invoked from DI ending 0805 hrs.

then delayed the outage start time. However, there would have been a very small window of time (a couple of minutes) to change the CA constraint set start time. Two possible outcomes could have eventuated from this scenario:

- AEMO control room delayed the CA constraint set start time and applied constraint ramping.

  This would have produced the same outcome as occurred on 1 May 2015.

- AEMO control room did not have enough time to change the CA constraint set start time before 0800 hrs. In other words, the CA constraint set became invoked at 0800 hrs without effective constraint ramping. A preliminary analysis, using offline NEM Dispatch Engine (NEMDE) rerun, has indicated that this could have produced a -$1,000/MWh dispatch price in QLD as well as in NSW for the first DI. The dispatch prices in the other regions would not differ materially from those observed during the constraint ramping on 1 May 2015. This is because the CA constraint sets would have been violated and relaxed via the over-constraint dispatch (OCD) rerun process in the same way that the ramping constraint equations were violated and relaxed via the OCD rerun process.

  This would have produced similar net market outcomes for all regions except Queensland. In Queensland, price outcomes may have been reduced, subject to generator rebidding.

5. BROADER ISSUES

5.1 Outage classification and publication

AEMO's Outage Assessment Procedure[12] states that an 'in-service' outage is for a power system service that is disabled but where the power flow capability of associated equipment is not affected. AEMO's automatic process does not publish 'in-service' type outages to the market via the NOS unless a constraint set is required for the outage.

As this outage required de-rating of the No.3 transformer, it should have been entered as an 'out of service' outage.

The outage information was first published via the NOS after the constraint set CA_SPS445534C8 was created on 1 May 2015.

AEMO plans to discuss this with TransGrid at the next AEMO-TransGrid meeting in August 2015.

5.2 System process for rating change

AEMO's MMS and EMS are unable to process a short notice temporary transformer rating change that is scheduled. A planned temporary rating change cannot be entered in advance and processed by AEMO's market forecast system (i.e. 5-minute Pre-dispatch and 30-minute Pre-dispatch) and the real-time network contingency analysis application. Current practice is to change the rating in EMS when the rating is to be effective in 5-minute Dispatch. This can lead to ineffective preparation for a planned outage that involves a rating change.

AEMO considers that the limitation in the current system design to process a short notice planned temporary rating change is an issue, however, it is very rare for a planned outage to have a material step change in rating. There are also alternatives to minimise potential impacts, such as taking the transformer out of service. Therefore, AEMO considers that this limitation does not present a higher risk than the regular rating changes that often create a sudden large step change in network flows. AEMO will review the current process for temporary rating changes.

5.3 Effectiveness of ramping period

On 1 May, the outage start time was delayed from 0800 hrs to 0900 hrs to create outage constraint equations and allow constraint ramping. The outage constraint set was invoked at 0806 hrs, just outside the 0830 hrs 30-minute Pre-dispatch run time. The first 30-minute Pre-dispatch that could process the outage constraint set was the 0900 hrs schedule. The 0900 hrs Pre-dispatch results were published at 0831 hrs, just outside of the 0835 hrs Dispatch run time. Hence, constraint ramping was applied from DI ending 0840 hrs. This allowed 4 DIs for ramping, instead of the default 6 DIs.

If the outage start time had been delayed longer (start after 0910 hrs), ramping would have occurred over 6 DIs with smaller step changes. Initial analysis has indicated that –$1,000/MWh dispatch price in NSW would not have occurred in the first two DIs if the ramping was applied over 6 DIs with smaller step sizes. However, the –$1,000/MWh dispatch price might not have been avoided in the third interval due to tight ramp rate capability at the time. The $13,500/MWh NSW price in the DI ending 0900 hrs was due to rebidding. It is difficult to accurately estimate what the price would have been in the

12 See http://www.aemo.com.au/Electricity/Policies-and-Procedures/System-Operating-Procedures/Outage-Assessment-SO_OP_3718.

subsequent intervals as it is difficult to predict rebidding. Depending on the market response, the resulting spot price could have been negative or higher than what it was.

It is difficult for AEMO to determine the optimum time for constraint ramping for each planned outage. Generally, AEMO applies ramping over 4 to 6 DIs and this is enough to achieve ramping successfully. For this event, ramping over 6 DIs might not have completely removed pricing disturbances and it could have resulted in negative or higher spot prices in some regions. To completely remove any material pricing disturbances, more than 6 DIs would have been required for this outage.

AEMO considers that 4 DIs for ramping was not ideal for this incident but acceptable as it accorded with current procedure.

AEMO has reviewed its internal procedure for network constraint ramping. AEMO will update the procedure to clarify the ramping process, particularly in regard to the number of 30-minute Pre-dispatch schedules required to allow 6 DIs for ramping.

5.4 Possible alternative to de-rating

After-event-analysis revealed that the outage would have had less impact if the Kemps Creek No.3 transformer was removed from service rather than being de-rated.

AEMO plans to discuss this alternate option with TransGrid at the next AEMO-TransGrid meeting in August 2015.

6. CONCLUSIONS AND RECOMMENDATIONS

On 30 April 2015, TransGrid incorrectly classified the Kemps Creek transformer No.3 maintenance work as an 'in-service' outage in the NOS and AEMO did not detect the error.

AEMO incorrectly assessed the outage and did not invoke a constraint set to manage the outage.

The outage information was not published to the market via the NOS before the scheduled outage start time, as the NOS does not publish an 'in-service' outage that does not require a constraint equation.

AEMO has concluded that a scheduling error occurred from DI 0730 hrs to DI 0900 hrs (19 DIs) on 1 May 2015 because AEMO failed to follow the central dispatch process by not invoking outage and ramping constraint sets in preparation for the planned outage originally requested on 30 April 2015, because the outage was incorrectly assessed at that time.

AEMO assessed that market outcomes would have been similar without the scheduling error, with potential reductions in Queensland spot prices, subject to generator rebidding. This is because the constraint ramping would not have been effective before the scheduled outage time, due to the limitation in AEMO's systems to process future rating changes in Pre-dispatch. Given the rarity of an outage that involves a transformer rating change, AEMO does not consider that this systems limitation presents a higher risk than regular rating changes. AEMO will review the current process for temporary rating changes.

AEMO has since addressed the issue with staff involved in the outage assessment. AEMO will make necessary changes to its staff training.

After-event-analysis revealed that the outage would have had less impact if the Kemps Creek No.3 transformer was removed from service rather than being de-rated.

AEMO plans to discuss this incident with TransGrid at the next AEMO-TransGrid meeting in August 2015.

Network constraint ramping was applied over four DIs, as opposed to the default six DIs. AEMO analysed that four DIs for ramping was not optimal but acceptable, as it accorded with current procedure. AEMO will update its internal procedure to clarify the constraint ramping process, particularly in regards to the number of 30-minute Pre-dispatch schedules required to allow six DIs for ramping.

APPENDIX A. NETWORK CONSTRAINT RAMPING

AEMO uses the Network Constraint Ramping tool to create soft and hard ramping constraint equations for a network outage constraint set. It is a prerequisite for the outage constraint set to be invoked in 30-minute Pre-dispatch in order to create the ramping constraints. The right-hand-side (RHS) of the ramping constraint equations are based on the 30-minute Pre-dispatch results.

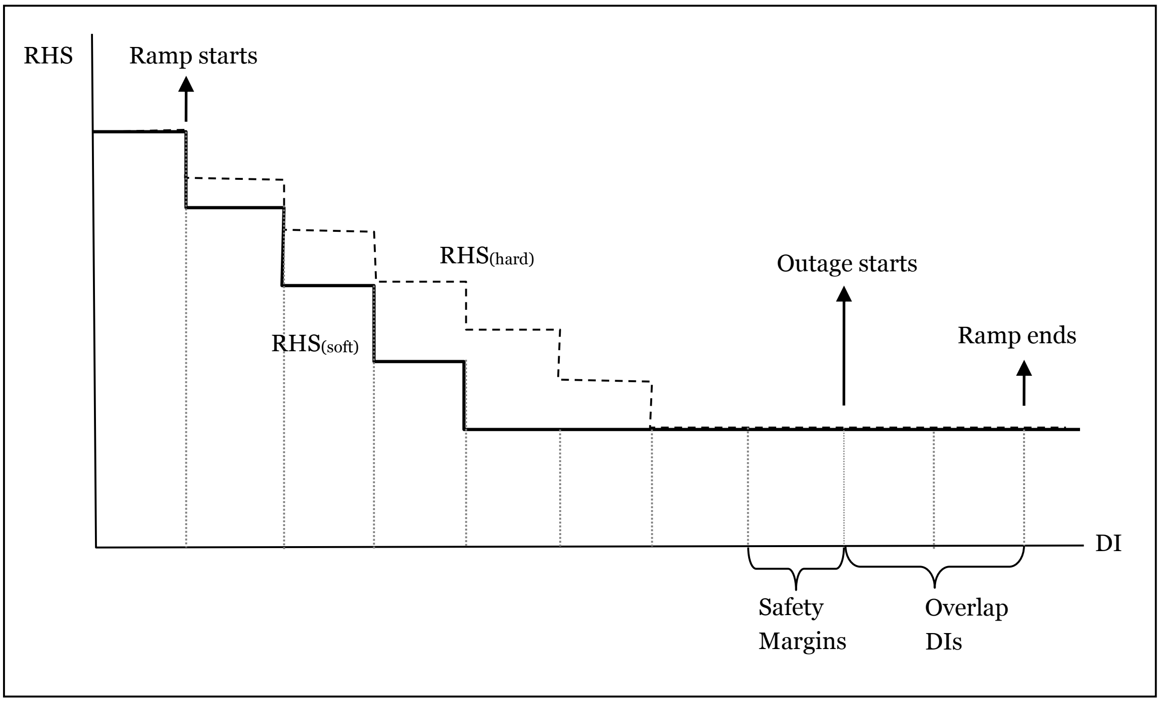
The Network Constraint Ramping tool applies constraint ramping over 6 dispatch intervals (DIs) by default. This allows ramping to start 7 DIs or 35 minutes before the outage start time - 6 DIs for ramping to the outage level and 1 DI as a safety margin. The 35 minute lead-time is equivalent to allowing the outage constraint set to be processed by two 30-minute Pre-dispatch schedules. The number of DIs required for ramping can be changed manually in the tool.

The Network Constraint Ramping process has the following features:

- Two types of ramping constraint equations are concurrently applied:
  - Soft ramping constraint: Ramping towards the final outage level, to minimise transient dispatch pricing disturbances that would otherwise occur without ramping. Soft ramping constraint equations have very small violation penalty factors and violation of the constraint set does not materially impact the pricing outcomes. Soft ramping constraint completes ramping two DIs prior to the completion of ramping by hard ramping constraint.
  - Hard ramping constraint: Ramping at slower rate than soft ramping, to ensure that outage is ready to proceed before the outage start time regardless of pricing outcomes.
- The right-hand-side (RHS) of the ramping constraint equations are calculated based on the 30-minute Pre-dispatch forecast. If the source outage constraint set has not been processed by 30-minute Pre-dispatch, ramping constraint equations cannot be created.
- The left-hand-side (LHS) of the ramping constraint equations are the same as their source outage constraint set.
- Current ramping process can be applied to any constraint sets related to the planned network outage except Frequency Control Ancillary Service (FCAS) constraint sets.
- The process automatically updates the constraint ramping targets (i.e. the constraint equation RHS value) based on the latest 30-minute Pre-dispatch results available prior to each DI.

The ramping process is depicted in Figure 1.

Figure 2 Ramping Process



where

- Safety Margins: Extra number of DIs added to make sure that the power flow is ramped down to the outage level prior to the outage commence time. The value is currently set to 1.
- Overlap DIs: Number of DIs required for the ramping constraint equation to overlap with the outage constraint set. The value is currently set to 2.

The Network Constraint Ramping tool has a default value of 6 DIs as the number of DIs required for ramping. This allows ramping to start 7 DIs (6 DIs for ramping and 1 DI for safety margin by default) before the outage start time. To achieve 6 DIs for ramping, the outage constraint set needs to be invoked at least one hour before the outage start time so the outage constraint set can be processed by two 30-minute Pre-dispatch schedules. The number of DIs required for ramping can be changed manually.

APPENDIX B. SEQUENCE OF EVENTS

Table 1 Sequence of Events

Date	Time	Events/Comments
30 April 2015	14:06	TransGrid submitted an ‘in-service’ outage for the Kemps Creek No.3 500/330kV transformer via the Network Outage Scheduler (NOS) and advised that the rating of the transformer be reduced to 600MVA during the outage from 1200MVA (normal rating) and 1638MVA (post-contingent rating). The outage to commence at 0715 hrs on 1 May 2015. (The outage start time was revised to 0800 hrs later.)
	17:30	AEMO assessed and approved the outage.
1 May 2015	07:58	Outage scheduled to start at 0800 hrs.
		AEMO entered the revised rating of 600MVA into the Energy Management System (EMS).
		AEMO’s network contingency analysis tool indicated that the revised rating would be exceeded following the loss of the Kemps Creek No.2 500/330kV transformer.
		AEMO delayed the outage start time to 0900 hrs to invoke a constraint set to manage the outage and allow constraint ramping.
	08:06	AEMO invoked a constraint set CA_SPS_445534C8, developed using Constraint Automation (CA), with a start time of 0900 hrs (i.e. DI ending at 0905 hrs).
	08:10 – 08:30	5-minute Pre-dispatch schedules forecast large price movements from 0900 hrs. VIC forecast price above $7,000/MWh. NSW forecast price -$1,000/MWh followed by $13,500/MWh.
	08:31	0900 hrs 30-minute Pre-dispatch (published at 0831 hrs) did not show large price movements: prices in all regions were forecast to be less than $300/MWh.
	08:32	Ramping constraint sets invoked for the constraint set CA_SPS445534C8.
	08:35	0840 hrs Dispatch (i.e. DI ending at 0840 hrs) published. Soft ramping constraints violated. No major pricing impact.
		0840 hrs 5-minute Pre-dispatch forecast -$1,000/MWh in NSW from DI ending at 0845 hrs.
	08:40	0845 hrs dispatch run (i.e. DI ending at 0845 hrs) published. NSW dispatch price -$1000/MWh. VIC dispatch price $452.91/MWh.
	08:45	Market Notice 48836 issued to advise the market of the invocation of the constraint set CA_SPS445534C8.
		0850 hrs Dispatch published. Negative residue action for VIC-NSW commenced. NSW dispatch price -$1000/MWh, TAS dispatch price -$963.69/MWh, VIC dispatch price $0/MWh, TAS Slow Raise FCAS price $13,100/MWh and TAS Raise Regulation FCAS price $13,100/MWh. Price review for manifestly incorrect input (MII) triggered. Prices unchanged.
	08:50	0855 hrs Dispatch published. NSW dispatch price -$1000/MWh. Price review for MII triggered. Prices unchanged.
		AEMO’s constraint builders are called to check the CA constraint formulation.
	08:55	0900 hrs Dispatch published. NSW dispatch price $13,500/MWh. VIC dispatch price $2,401.18/MWh. Negative residue management constraint violated. Price review for MII triggered. Prices unchanged.
	08:58	AEMO checked the suitability of the constraints developed by the CA tool and confirmed that the constraints were in accordance with the constraint formulation guidelines.
	09:00	Outage commenced. No power system issue.
		0905 hrs Dispatch published. No constraint violation. Prices in normal range. NSW dispatch price $170/MWh. VIC dispatch price $126.56/MWh. Price review for MII triggered. Prices unchanged.

Date	Time	Events/Comments
	09:05 I 10:15	Prices in normal range. Price review for MII triggered for DIs ending 0910 hrs, 1000 hrs, 1005 hrs, and 1010 hrs. Prices unchanged.
	10:20	Outage ceased. TransGrid advised that the cooling system at Kemps Creek No.3 transformer was restored and the work was compete. CA constraint set revoked (i.e. constraint equations invoked until DI ending 1025 hrs) and the rating on the transformer restored.

APPENDIX C. CONSTRAINT EQUATIONS

C.1 Contingency Analysis Constraint

C.1.1 CA_SPS_445534C8_01

Constraint type: LHS<=RHS

Effective date: 01/05/2015

Weight: 30

Constraint active in: Dispatch and DS PASA, Predispatch and PD PASA, ST PASA

5 Min Predispatch RHS: Dispatch

Active in PASA for: LRC & LOR

Constraint description: Constraint Automation, O/L KEMPS_CK TRANSF 3L for CTG TNVB on trip of KEMPS_CK 2 500/330KV TX.

Impact: NSW Generation + Interconnectors

Source: Constraint Automation

Limit type: Thermal

Reason: Trip of KEMPS_CK 2 500/330KV TX

LHS=

0.1565 x Bayswater unit 1 (ENERGY)

0.1565 x Bayswater unit 2 (ENERGY)

0.1016 x Bayswater unit 3 (ENERGY)

0.1016 x Bayswater unit 4 (ENERGY)

-0.0826 x Blowering hydro (3 aggregated units) (ENERGY)

-0.0895 x BOCO Rock WF (ENERGY)

-0.1027 x Woodlawn wind farm (ENERGY)

-0.1404 x Tallawarra CCGT (ENERGY)

0.4907 x Eraring unit 1 (ENERGY)

0.4906 x Eraring unit 2 (ENERGY)

+ Eraring unit 3 (ENERGY)

+ Eraring unit 4 (ENERGY)

-0.0739 x Gullen Range WF (ENERGY)

-0.0863 x Guthega hydro (2 aggregated units) (ENERGY)

-0.0857 x Hume (NSW) hydro (ENERGY)

0.1699 x Hunter GT (2 aggregated units) (ENERGY)

0.1699 x Liddell unit 1 (ENERGY)

0.1699 x Liddell unit 2 (ENERGY)

0.1699 x Liddell unit 3 (ENERGY)

0.1699 x Liddell unit 4 (ENERGY)

0.0863 x Lower Tumut pumps (3 aggregated pumps) (ENERGY)

-0.0863 x Lower Tumut hydro (6 aggregated units) (ENERGY)

-0.1311 x Shoalhaven hydro (aggregated Bendeela and Kangaroo Valley units) (ENERGY)

0.1311 x Shoalhaven pumps (2 aggregated pumps) (ENERGY)

-0.0851 x Uranquinty GT unit 1 (ENERGY)

-0.0851 x Uranquinty GT unit 2 (ENERGY)

-0.0851 x Uranquinty GT unit 3 (ENERGY)

-0.0851 x Uranquinty GT unit 4 (ENERGY)

-0.0864 x Upper Tumut hydro (8 aggregated units) (ENERGY)

0.3884 x Vales Pt unit 5 (ENERGY)

0.3884 x Vales Pt unit 6 (ENERGY)

-0.0799 x Gunning Wind Farm (ENERGY)

-0.1959 x MW flow north on the Terranora Interconnector

-0.186 x MW flow north on the QNI AC Interconnector

-0.0861 x MW flow north on the Vic to NSW AC Interconnector

RHS

Default RHS value= 10000

Dispatch RHS=

-2.1169 x (-1 x [MW flow on Kemps Creek #3 500/330kV transformer]

- 0.7423 x [MW flow on Kemps Creek #2 500/330kV transformer]

- NSW: Kemps Creek 500/330kV #3 transformer 2 hour rating

+ 30 {Margin})

+ 0.1565 x [Bayswater unit 1]

+ 0.1565 x [Bayswater unit 2]

+ 0.1016 x [Bayswater unit 3]

+ 0.1016 x [Bayswater unit 4]

+ 0.4907 x [Eraring unit 1]

+ 0.4906 x [Eraring unit 2]

+ Eraring unit 3

+ Eraring unit 4

+ 0.1699 x [Liddell unit 1]

+ 0.1699 x [Liddell unit 2]

+ 0.1699 x [Liddell unit 3]

+ 0.1699 x [Liddell unit 4]

+ 0.3884 x [Vales Pt unit 5]

+ 0.3884 x [Vales Pt unit 6]

- 0.1404 x [Tallawarra CCGT]

- 0.0895 x [BOCO Rock WF]

- 0.0799 x [Gunning Wind Farm]

- 0.0851 x [Uranquinty GT unit 1]

- 0.0851 x [Uranquinty GT unit 2]

- 0.0851 x [Uranquinty GT unit 3]

- 0.0851 x [Uranquinty GT unit 4]

- 0.1027 x [Woodlawn wind farm]

- 0.1959 x [MW flow north on the Terranora Interconnector]

- 0.0826 x [Blowering hydro (3 aggregated units)]

- 0.0857 x [Hume (NSW) hydro]

- 0.0861 x [MW flow north on the Vic to NSW AC Interconnector]

- 0.186 x [MW flow north on the QNI AC Interconnector]

+ 0.1699 x [Hunter GT (2 aggregated units)]

- 0.1311 x [Shoalhaven hydro (aggregated Bendeela and Kangaroo Valley units)]

- 0.0739 x [Gullen Range WF]

- 0.0864 x [Upper Tumut hydro (8 aggregated units)]

- 0.0863 x [Lower Tumut hydro (6 aggregated units)]

- 0.0863 x [Guthega hydro (2 aggregated units)]

+ 0.1311 x [Shoalhaven pumps (2 aggregated pumps)]

+ 0.0863 x [Lower Tumut pumps (3 aggregated pumps)]

C.1.2 CA_SPS_445534C8_02

Constraint type: LHS<=RHS

Effective date: 01/05/2015

Weight: 30

Constraint active in: Dispatch and DS PASA, Predispatch and PD PASA, ST PASA

5 Min Predispatch RHS: Dispatch

Active in PASA for: LRC & LOR

Constraint description: Constraint Automation, O/L KEMPS_CK TRANSF 3L for CTG TNVA on trip of ERARING 2 500/330KV TIE TX.

Impact: NSW Generation

Source: Constraint Automation

Limit type: Thermal

Reason: Trip of ERARING 2 500/330KV TIE TX

LHS=

Eraring unit 3 (ENERGY)

+ Eraring unit 4 (ENERGY)

RHS

Default RHS value= 10000

Dispatch RHS=

-2 x (-1 x [MW flow on Kemps Creek #3 500/330kV transformer]

- 0.4879 x [MW flow on Eraring #2 500/330kV transformer]

- NSW: Kemps Creek 500/330kV #3 transformer 2 hour rating

+ 30 {Margin})

+ Eraring unit 3

+ Eraring unit 4

C.2 Ramping Constraint

C.2.1 #R012237_001_RAMP_V

Soft ramping constraint for constraint CA_SPS_445534C8_01.

LHS is the same as the constraint CA_SPS_445534C8_01 LHS.

RHS calculation is described in section 2.3.

C.2.2 #R012237_001_RAMP_F

Hard ramping constraint for constraint CA_SPS_445534C8_01.

LHS is the same as the constraint CA_SPS_445534C8_01 LHS.

RHS calculation is described in section 2.3.

C.2.3 # R012237_002_RAMP_V

Soft ramping constraint for constraint CA_SPS_445534C8_02.

LHS is the same as the constraint CA_SPS_445534C8_02 LHS.

RHS calculation is described in section 2.3.

C.2.4 # R012237_002_RAMP_F

Hard ramping constraint for constraint CA_SPS_445534C8_02.

LHS is the same as the constraint CA_SPS_445534C8_01 LHS.

RHS calculation is described in section 2.3.

APPENDIX D. OUTAGE AND RAMPING CONSTRAINT

D.1 Outage constraint

The CA constraint set CA_SPS_445534C8 had the following two constraint equations.

- CA_SPS_445534C8_01
- CA_SPS_445534C8_02

The constraint equation CA_SPS_445534C8_01 was to manage post-contingent overload on Kemps Creek Transformer No.3 on trip of Kemps Creek Transformer No.2 by constraining NSW generation and interconnectors flows. Generation from northern NSW power stations and interconnector flows from Queensland (QLD) to NSW could potentially contribute to the overload, while generation from NSW power stations south of Sydney and interconnector flows from VIC to NSW could potentially relieve the overload. Accordingly, the constraint equations attempted to reduce the northern NSW generation and imports from QLD to NSW by assigning positive coefficients[13], and increase the southern NSW generation and interconnector flows from VIC to NSW by assigning negative coefficients. Generating units with the largest impact were assigned the largest coefficients and these were the Eraring and Vales Point generating units. Other NSW generating units and the interconnector flows would have relatively minor impact compared to Eraring and Vales Point, thus had small coefficients (See Figure 1 for network diagram for their relative location. See section 3.5.1 for the constraint coefficients).The constraint equation CA_SPS_445534C8_02 was invoked to manage post-contingent overload on Kemps Creek Transformer No.3 on trip of Eraring No.2 500/330kV tie transformer. This constant equation constrained generation from Eraring units 3 and 4.

D.2 Ramping constraint

The outage constraint set CA_SPS_445534C8 was processed in the 0900hrs 30-minute Pre-dispatch run (results published at 08:31 hrs). At 0832 hrs, AEMO invoked the ramping constraint set, comprising soft and hard ramping constraint equations automatically developed[14] based on the outage constraint results from the 0900 hrs 30-minute Pre-dispatch run. The ramping constraint equations applied from DI ending at 0840 hrs (dispatch results published at 0835 hrs).

D.2.1 Ramping for Constraint CA_SPS_445534C8_01

To manage post-contingent overload on Kemps Creek Transformer No.3 on trip of Kemps Creek Transformer No.2, NSW generation and interconnector flows appearing on the LHS of the outage constraint set CA_SPS_445534C8_01 had to be ramped from the initial level of 2308.30[15] to the post-contingent outage level of 1780.79[16] prior to the outage start time. The soft and hard ramping constraint equations attempted to achieve this reduction of 527.5 ($\approx$ 2308.30-1780.79) by DI ending 0845 hrs and 0855 hrs respectively[17]. This meant 2 DIs for soft constraint ramping and 4 DIs for hard constraint ramping. The LHS terms of the soft and hard ramping constraint equations were the same as the LHS of the outage constraint equation and can be simplified as below.

[13] For Terranora and Queensland and New South Wales Interconnector (QNI) flows, positive flow is from NSW to QLD. The constraint equation has negative coefficients for Terranora and QNI flows as the interconnector flows are represented in northerly flow direction as per the NEM convention.

[14] See Appendix C.2 for a description

[15] LHS value of the outage constraint equation CA_SPS_445534C8_01, calculated based on the initial conditions just prior to the start of ramping.

[16] 30-minute Pre-dispatch RHS value of the outage constraint equation CA_SPS_445534C8_01.

[17] Refer to section 2.3 for current design.

1 x Eraring Units 3&4 + 0.4907 x Eraring Unit 1 + 0.4906 x Eraring Unit 2 + 0.3884 x Vales Pt Units 5&6

+ Small coefficients x Other northern NSW generation

– Small coefficients x Southern NSW generation

-0.1959 x Terranora Interconnector flow – 0.186 x QNI flow -0.0861 x VIC to NSW interconnector flow

Ramping a unit or interconnector flow with a large coefficient can provide more effective ramping than ramping entities with small coefficients. For example, reducing the constraint equation RHS value by 1 can be met by reducing the Eraring Unit 3 by 1MW or increasing the VIC to NSW interconnector flow by 11.61MW (=1/0.0861). Eraring and Vales Point units had the largest coefficients in the constraint equation, but their combined ramping capability at the time[18] was not enough to meet the required step changes. Consequently, other NSW generation and interconnector flows with small coefficients were moved by large amounts. The soft ramping constraint equation was violated from DI ending 0840 hrs to DI ending 0900 hrs. The hard ramping constraint equation was violated from DI ending 0845 hrs to DI ending 0900 hrs.

D.2.2 Ramping for Constraint CA_SPS_445534C8_02

To manage post-contingent overload on Kemps Creek Transformer No.3 on trip of Eraring Transformer No.2, Eraring Units 3 and 4 were ramped from the initial level of 1354.85[19] to the post-contingent outage level of 1224.86[20], resulting a combined generation reduction of 130MW (≈1354.85-1224.86).

Eraring Units 3 and 4 had a combined ramp rate of 8MW/min (i.e. 40MW in 5 minutes) from DI ending 0840 hrs to 0855 hrs. The soft ramping constraint equation was violated from DI ending at 0840 hrs to DI ending at 0855 hrs. The hard ramping constraint equation was violated from DI ending 0845 hrs to DI ending 0855 hrs.

[18] Eraring Unit 1 and Vales Pt Unit 6 were not available at the time. Eraring Units 2 and 3 had a ramp rate of 5MW/min initially. This ramp rate was reduced to 3MW/min from DI ending at 0900 hrs. Eraring Unit 4 had a ramp rate of 3MW/min during the event. Vales Pt Unit 5 had a ramp rate of 5MW/min initially. This ramp rate was reduced to 3MW/min from DI ending at 0850 hrs

[19] LHS value of the outage constraint equation CA_SPS_445534C8_02, calculated based on the initial conditions just prior to the start of ramping.

[20] 30-minute Pre-dispatch RHS value of the outage constraint equation CA_SPS_445534C8_02.

APPENDIX E. MARKET CONDITIONS AND OUTCOMES – 1 MAY 2015

Tables 2 and 3 highlight the unusual dispatch and spot prices (by presenting the less important prices in lighter colour) that occurred during the outage ramping period. Table 3 summarises the market conditions and outcomes. DIs shown in these tables are the DI ending time[21].

Table 2 Dispatch Price – 1 May 2015

Dispatch Interval	Energy Dispatch Price ($/MWh)					FCAS TAS Price ($/MWh)	
	NSW	QLD	SA	TAS	VIC	Slow Raise	Raise Regulation
08:40	204.82	16.70	117.23	37.53	137.51	0.80	2.00
08:45	-1,000.00	6.99	70.30	32.05	452.91	0.80	3.00
08:50	-1,000.00	15.05	0.00	-963.39	0.00	13,100.00	13,100.91
08:55	-1,000.00	16.75	0.00	-0.01	0.00	0.80	1.80
09:00	13,500.00	39.25	287.95	32.05	2,401.18	0.80	3.00
09:05	170.81	26.55	37.02	12.93	126.59	0.80	1.96

Table 3 Trading Price – 1 May 2015

Trading Interval	Energy Trading Price ($/MWh)					Sum of FCAS prices ($/MWh)
	NSW	QLD	SA	TAS	VIC	TAS (sum of all services)
09:00	1,792.03	23.67	86.79	-137.27	505.44	4,375.59

Table 4 Market Outcomes – 1 May 2015

Dispatch Interval	Analysis
08:40	• Soft ramping constraint violation. No hard ramping constraint violation. • Constraint V>>V_NIL_2A_R binding. • Decreased northern NSW generation. Decreased flow from QLD to NSW. Increased flow from VIC to NSW.
08:45	• Soft and hard ramping constraint violation. • Constraint equation V>>N-NIL_HA binding. • Constraint V>>V_NIL_2A_R binding.
08:50	• Soft and hard ramping constraint violation. • Rebidding in TAS: 1504 MW of generation capacity rebid from higher priced bands to bands priced at or less than -$964.25/MWh. Up to 333 MW of available Slow Raise and Regulation Raise FCAS capacity rebid from bands priced at or less than $3.32/MWh to bands priced higher than $13,442/MWh. • Rebidding in VIC: 1260 MW of generation capacity shifted from higher priced bands to bands priced at or below $0/MWh. • Negative residue management (NRM) constraint equation NRM_VIC1_NSW1 binding, reducing counter-price flows across the VIC-NSW directional interconnector. • Constraint equation V>>N-NIL_HA no longer binding, allowing for increased generation within New South Wales with the reduced flow across the VIC-NSW interconnector.
08:55	• Soft and hard ramping constraint violation.

[21] If comparing against the table in Appendix B, it should be noted that the “Time” in Appendix B is the actual time. For example, dispatch interval ending 0840 hrs is published at 0835 hrs – Appendix B table shows 08:35 in the “Time” column and Tables 1 and 2 and Appendix E show 08:40 as the DI.

Dispatch Interval	Analysis
09:00	• Soft and hard ramping constraint violation for the ramping constraints created for CA_SPS_445534C8_01. No violation for the ramping constraints created for CA_SPS_445534C8_02. • Constraint equation V>>N-NIL_HA binding. • Constraint V>>V_NIL_2A_R binding. • Rebidding in NSW: Withdrawal of 1068 MW of generation capacity. • Rebidding in TAS: 1504MW of generation capacity rebid into higher price bands but still offered at negative prices. • Increased interconnector flow from VIC to NSW, violating the NRM constraint equation NRM_VIC1_NSW1. • Cheaper priced generation in New South Wales was constrained off by the ramping constraints or required more than one DI to synchronise. • Increased VIC price due to increased export from VIC to NSW and cheaper priced generation within VIC being limited by ramp rates or constrained off by the system normal constraint equation, V>>V_NIL_2A_R.
09:05	• No constraint violation. • Constraint V>>V_NIL_2A_R binding. • Rebidding in NSW: 890 MW of generation capacity in New South Wales shifted from bands priced at or above $25.52/MWh to Market Floor price. Flow on the VIC-NSW interconnector reduced.

The unusual pricing outcomes were forecast by 5-minute Pre-dispatch but not by 30-minute Pre-dispatch because 30-minute Pre-dispatch could not detect issues related to 5-minute ramping capability.

A large step change was required to the interconnector flows and southern New South Wales generation to manage the outage as the northern New South Wales generation that could relieve the post-contingent overload was ramp-rate bound.

As a consequence of binding or violating constraint equations due to the Kemps Creek No.3 transformer rating change and limited 5-minute ramping capability and generation capacity rebidding, there were large price movements in New South Wales, Victoria and Tasmania.

The NSW 5-minute Dispatch price collapsed to the Market Floor Price (-$1,000/MWh) due to the following reasons:

- Insufficient 5-minute ramping capability in NSW to reach the post-contingent outage level within the required time. Ramping constraint equations violated.
- Excess generation capacity in NSW due to large amount of constrained-on generation and increased interconnector flows into NSW due to
  - Binding/violating ramping constraint equations and binding system normal constraint equation V>>N-NIL_HA.
  - Constrained-off generation in northern NSW and constrained-on generation in southern NSW.
  - Heavily reduced import into NSW from QLD and increased export from VIC to NSW. Overall, increased import into NSW.

The NSW dispatch price reached $13,500/MWh mainly due to withdrawal of 1068MW of generation capacity in NSW. This led to increased interconnector flows from VIC to NSW as cheaper priced generation in NSW was limited by the ramping constraint equations or required more than one DI to synchronise. This, in turn, increased the VIC dispatch price to $2,401.18/MWh as cheaper priced generation in VIC was limited by ramp rate capability or constrained off by the system normal constraint equation, V>>V_NIL_2A_R.

The price disturbances in Tasmania were due to rebidding. 1504 MW of generation capacity in Tasmania was rebid to bands priced at or less than -$964.25/MWh. Up to 333 MW of available capacity in the Slow Raise and Regulation Raise FCAS markets were rebid from bands priced at or less than $3.32/MWh to bands priced higher than $13,442/MWh.

Dispatch prices returned to normal in DI ending 0905 hrs as 890 MW of generation capacity in NSW was shifted from bands priced at or above $25.52/MWh to Market Floor price. This reduced the target flow across the VIC-NSW interconnector to 1492 MW.

Counter-price flow occurred on the VIC to NSW directional interconnector between DI ending 0845 hrs and 0855 hrs. AEMO invoked negative settlements residue management (NRM) constraint sets to manage negative settlements residue from DI ending 0845 hrs to 0915 hrs (Market Notices No. 48839 and 48850). The combination of positive and negative dispatch prices in the trading interval (TI) ending 0900 hrs lessened the overall pricing impact for the TI. The spot price was averaged to $1,792.03/MWh in NSW and this made the inter-regional settlements residue on the VIC to NSW directional interconnector positive for the TI.

The system normal constraint equations V>>N-NIL_HA and V>>V_NIL_2A_R had a number of LHS terms that were shared with the outage constraint equations CA_SPS_445534C8_01 and CA_SPS_445534C8_01[22] but the coefficients were of opposite sign. Hence, these system normal constraint sets interacted with the ramping constraint equations and impacted the interconnector flows and dispatch of NSW and VIC generation.

Price revision occurred for DI ending 0845 hours. An automated over-constrained dispatch (OCD) run was performed just after the prices were published to resolve the violated constraint sets. The firm prices were published shortly after (Market Notice 48838).

Price review for Manifestly Incorrect Input (MII) was triggered for a number of DIs. Prices were unchanged.

[22] For example, the system normal constraint equations V>>N-NIL_HA and V>>V_NIL_2A_R had positive coefficients for the VIC to NSW directional interconnector flows whereas the outage constraint equations CA_SPS_445534C8_01 and CA_SPS_445534C8_01 had negative coefficients for the same interconnector flows.

ABBREVIATIONS

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator Ltd
CA	Constraint Automation
DI	Dispatch Interval
EMS	Energy Market System
kV	Kilo volt
LHS	Left-Hand-Side
MFP	Market Floor Price
MII	Manifestly Incorrect Input
MMS	Market Management System
MPC	Market Price Cap
MVA	Mega volt ampere
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NOS	Network Outage Scheduler
NRM	Negative Residue Management
NSW	New South Wales
OCD	Over-Constrained Dispatch
QLD	Queensland
QNI	Queensland – New South Wales 330kV interconnector
RHS	Right-Hand-Side
SA	South Australia
VIC	Victoria
TAS	Tasmania
TI	Trading Interval