AEMC

Australian Energy Market Commission

Rule Determination

National Electricity Amendment (Compensation Arrangements Under Administered Pricing) Rule 2008

Rule Proponent
EnergyAustralia

18 December 2008

Signed:..

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Chairman
For and on behalf of
Australian Energy Market Commission

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy markets. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market. It is a statutory authority. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

Contents

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
APC	Administered Price Cap
APP	Administered Price Period
Commission	see AEMC
CPT	Cumulative Price Threshold
CRR	Comprehensive Reliability Review
EA	EnergyAustralia
ERAA	Energy Retailers Association of Australia
FCAS	Frequency Control Ancillary Services
IES	Intelligent Energy Systems
IRFM	Industrial Relations Force Majeure
IRSR	Inter-Regional Settlement Residues
MCE	Ministerial Council on Energy
MNSP	Market Network Service Provider
MWh	Megawatt Hour
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMMCO	National Electricity Market Management Company Limited
NEO	National Electricity Objective
NGF	National Generators Forum
QNI	Queensland/ New South Wales Interconnector
Panel	AEMC Reliability Panel
RRN	Regional Reference Node
RRP	Regional Reference Price
Rules	National Electricity Rules
SCO	Standing Committee of Officials
SRMC	Short Run Marginal Costs
TNSP	Transmission Network Service Provider
VoLL	Value of Lost Load

Summary

On 10 December 2007, Energy Australia (EA) submitted a Rule change proposal relating to how compensation is calculated following the application of an administered price cap (APC), market suspension event, value of lost load (VoLL), or market floor price under the National Electricity Rules.

The Rule change proposal consists of four core elements:

1. Removal of the requirement for the expert panel to take into account the difference between the spot price resulting from the APC and a Scheduled Generator's dispatch price when assessing compensation;

2. Inclusion of a clear statement in the Rules that the purpose of any compensation payment to Scheduled Generators is to recover direct generating costs incurred in respect of dispatched generating units and the specification of the nature of direct costs;

3. A requirement that the Commission publish the expert panel's report and its proposed compensation decision, and invite submissions from interested parties for a period of 20 days prior to making a final decision; and

4. Inclusion of a statement indicating that the Commission is required to take into account the expert panel's report, but is not bound by the panel's recommendations.

First round consultation

The Australian Energy Market Commission (Commission) published the Rule change proposal in accordance with section 95 of the National Electricity Law (NEL) and submissions closed on 22 February 2008. Five first round submissions were received.

The submissions supported the basis of EA's proposal to enhance the transparency of the compensation process following administered pricing. However, there were differences of opinion about how compensation should be calculated.

The Commission's draft determination and draft changes to EA's proposed Rule Change

On 25 September 2008, the Commission made a draft Rule determination and draft Rule on the provision of compensation following the application of an administered price cap (APC), market suspension event, value of lost load (VoLL), or market floor price in accordance with Section 99 of the NEL.

The Commission accepted some of EA's proposed changes, added some changes proposed in submissions and also drafted changes of its own where it considered that these changes would further promote the National Electricity Objective (NEO).

Second round consultation

The Commission published the draft Rule determination in accordance with section 99 of the NEL and submissions closed on 7 November 2008. Two second round submissions were received on this draft Rule and draft Rule determination.

The submissions largely supported the draft Rule and were of the opinion that the Rule change would remove uncertainty and enhance the transparency of the compensation process. Both submissions also supported the inclusion of opportunity costs when determining compensation, although it was noted that the process for calculating such costs needs to be clearly defined.

The Commission's final determination

The Commission makes this final Rule determination and the Rule as made (the "final Rule") on EA's Rule change proposal, in accordance with sections 102 and 103 of the NEL.

The Commission considers that the final Rule is likely to contribute to the promotion of the NEO. The final Rule would improve the transparency and consistency of the process used to calculate compensation. This in turn would promote efficient investment in electricity services and regulatory certainty for the benefit of consumers. In addition the proposed amendments to EA's proposal are likely to promote greater reliability and security in the National Electricity Market (NEM), by maintaining the incentive for supplying electricity during an administered price period.

For these reasons the Commission considers that the Rule making test under section 88 of the NEL is satisfied.

Rule Commencement

The final Rule is scheduled to commence operation on 1 January 2009.

1 EnergyAustralia's Rule change proposal

On 10 December 2007, Energy Australia (EA) submitted a Rule change proposal to the Commission regarding how compensation is calculated following application of an administered price cap (APC), market suspension event, value of lost load (VoLL), or market floor price.

This chapter outlines:

- EA's Rule change proposal
- The policy context and background
- Linkages to other matters before the Commission;
- First round consultation;
- Consultancy reports commissioned by the Commission; and
- Second round consultation.

1.1 Summary of EnergyAustralia's Rule change proposal

EA seeks to modify clause 3.14.6 of the Rules to change the criteria and process for determining compensation following administered pricing. The purpose of the Rule change is to clarify the compensation process and ensure that compensation to Scheduled Generators is based on their "direct generating costs" rather than on their offer prices.

EA seeks to make the following four amendments to the compensation provisions in clause 3.14.6 of the Rules:

1. Removal of the requirement for the expert panel to take into account the difference between the spot price resulting from the APC and a Scheduled Generator's offer price when assessing compensation;

2. Inclusion of a clear statement in the Rules that the purpose of any compensation payment to Scheduled Generators is to recover direct generating costs incurred in respect of dispatched generating units and the specification of the nature of direct costs;

3. A requirement that the Commission publish the expert panel's report and its proposed compensation decision, and invite submissions from interested parties for a period of 20 days prior to making a final decision; and

4. Inclusion of a statement indicating that the Commission is required to take into account the expert panel's report, but is not bound by the panel's recommendations.

EA's proposed Rule change is motivated by concerns about the current compensation provisions following administered pricing, namely:

- A lack of clarity in the criteria for determining compensation;

- The use of offer prices as a basis for determining compensation;
- Concerns that current provisions create significant financial risks for retailers; and
- A lack of transparency in the compensation process.

1.1.1 Lack of clarity in the criteria for determining compensation

EA's Rule change proposal indicates that it is unclear how the criteria for determining compensation under clause 3.14.6 of the Rules may be interpreted and applied by the expert panel and the Commission. EA suggests that this creates uncertainty as to how much compensation will be awarded, as the Rules provide the panel and the Commission with broad discretion to determine what is a "fair and reasonable" amount of compensation. EA considers that this lack of clarity may result in compensation determinations ranging between zero and the difference between the capped spot price and the generator's offer price.

EA also suggests that the current Rules provide the expert panel with no specific guidance as to the initial threshold question of whether compensation should be paid or not paid, other than whether it is "appropriate" for compensation to be paid.

EA considers that its Rule change proposal will address these issues by:

- Removing the existing references in the Rules to the generator's offer price in the compensation criteria;
- Specifying in the Rules that the purpose of any compensation payable to a Scheduled Generator is to recover its direct costs; and
- Specifying the nature of direct costs that can be claimed.

EA's proposal also seeks to delineate between the two tasks of deciding whether compensation should be awarded and determining the quantum of compensation that should be paid. Under EA's proposed Rule change, the expert panel would be required to firstly consider whether it was appropriate for compensation to be paid; and if compensation was found to be appropriate, would secondly determine the level of compensation to be paid. The Commission would then make a final decision on both matters after taking into account the recommendations of the expert panel.

1.1.2 Offer prices as a basis for compensation

EA suggests that using a generator's offer price as a basis for compensation determinations will contribute to an increase in the level of market risk, contrary to the original intent of the CPT/Administered Price Period (APP). EA states that the "intent of the CPT/APP arrangements is to ensure market risk is capped during extreme market events".[1]

[1] EneryAustralia, 2007, Compensation Under Administered Pricing Rule change proposal, 10 December, p. 5. Available at: http://www.aemc.gov.au/electricity.php?r=20071106.104606

EA considers that allowing compensation claims to be based on generator offer prices will affect market behaviour and outcomes in ways not envisaged or intended by the Rule designers. This is because it would render the capping of the spot price ineffectual and may give rise to high levels of compensation, equivalent to the difference between the generator's capped spot price and their offer price. EA notes that this may lead to a "pay as bid" compensation regime. EA suggests that pay as bid compensation may result in generators basing their offers to NEMMCO during an APP not on their costs, but on what each generator forecasts the future clearing price will be. This would enable the generator to be dispatched with the ability to claim compensation. EA suggests that this may lead to higher dispatch costs, lower dispatch efficiency and may jeopardise system security and reliability.

EA considers that its Rule change proposal will address the risk of pay as bid compensation by removing the existing references in the Rules to the generator's offer price in the compensation criteria and specifying in the Rules that the purpose of any compensation payable to a Scheduled Generator is to recover its direct costs. EA's proposed Rule will also specify the nature of the direct costs that compensation can be claimed against by Scheduled Generators.

1.1.3 Current provisions create significant financial risks for retailers

EA states that compensation payments cannot be hedged by retailers under conventional financial hedge contracts. As a result, EA claims that retailers and their customers remain exposed to the full financial impact of these large and uncertain costs. EA suggests that retailers are required to maintain a large amount of risk capital to cover their potential exposure to compensation payouts, and that retailers which are unable to afford this risk capital may become insolvent as a consequence of high compensation payouts. EA suggests that this may lead to:

- Systemic risk in the retail market;
- Higher costs of capital for existing retailers;
- Higher barriers to entry for new retailers; and
- The triggering of new government or regulatory intervention which may further damage the competitiveness and efficiency of the retail market.

Further, EA considers that any retailer "claw back" of the cost of compensation from customers, is likely to lead to substantial hardship particularly for residential customers. EA indicates that clawback of the costs of compensation from customers on regulated tariffs would also be subject to regulatory approval, which would take a considerable amount of time. EA notes that even if a claw back was approved by regulators, there would still be a delay before the claw back monies were received by retailers. Therefore, EA suggests that retailers would still require access to substantial working capital in the intervening period in order to pay their share of compensation within the 15 day settlement period provided for under clause 3.15.10 of the Rules.

EA suggests that its proposed changes will address these issues by reducing the risk of high levels of compensation arising from the application of the APC and uncertainty about how compensation will be determined. EA suggests that in turn this will reduce the risks for retailers and their customers that arises from being unable to hedge against high compensation payments. EA indicates that their Rule change proposal will achieve this by:

- Removing the existing references in the Rules to the generator's offer price in the criteria used to determine compensation by the expert panel;
- Specifying in the Rules that the purpose of any compensation payable to a Scheduled Generator is to recover its direct costs; and
- Identifying the nature of the direct costs that compensation can be claimed against by Scheduled Generators.

1.1.4 Lack of transparency in the compensation process

EA considers that the process for determining compensation lacks transparency. In particular, EA suggests that there is no opportunity for interested parties to be involved in the panel's deliberations or to be consulted with before the Commission makes a decision on the quantum of compensation to be awarded.

EA also proposes to increase the transparency of the compensation process by requiring the Commission to invite submissions from interested parties for a period of 20 days before making its final decision. EA's proposed Rule also specifies that in making its final decision, the Commission will be required to take into account the panel's recommendations and submissions, but will not be bound by the panel's recommendations.

1.2 Policy Context and Background

The design of the NEM can lead to systemic price volatility, which creates financial risks for individual Market Participants and the market as a whole. The CPT and APC arrangements are designed to mitigate the market wide risks of sustained extreme prices.

1.2.1 Why are prices in the NEM volatile?

Price volatility is created by the following features of the NEM:

1. It is an energy only market. Spot market income for generators is earned solely from energy generated as there is no separate payment for generation capacity that is made available to the market;

2. The demand for electricity is volatile as it varies with the time of day and season; and

3. The demand for electricity is relatively inelastic to price.

As a consequence of this inherent volatility, at times the price of electricity in the NEM can remain at relatively high levels over a number of days.

1.2.2 Why is price volatility necessary in the NEM?

Price volatility is essential for recovering fixed costs in an energy only market. It also plays an important role in signalling the need for new investment. As there are no capacity payments, there needs to be sufficient periods of time in the year when the spot price is high enough that settlement payments to generators are above their short run marginal costs and are able to contribute to their fixed costs. At times of energy scarcity, Market Participants have an incentive to drive up spot prices beyond their SRMC to allow them to recover fixed costs.

1.2.3 What kinds of risks does price volatility lead to?

Price volatility creates risks for individual Participants, which can be mitigated via financial hedge contracts and insurance.

Price volatility can also create systemic market wide risks. For instance, the collapse of a single Market Participant which defaults on its payments may have a cascading effect on other financial counterparties and trigger a chain of financial defaults throughout the market.

1.2.4 What arrangements does the NEM have to mitigate market wide risks?

A package of risk mitigation provisions can be invoked by NEMMCO during periods of prolonged high prices, in order to sustain electricity trading and limit the financial risks of Market Participants. These provisions and the circumstances in which they can be invoked are set out in Rule 3.14 of the Rules and include:

- the CPT;
- the APC; and
- the compensation provisions which apply following administered pricing.

1.2.5 How do the CPT and APC operate?

Under the current arrangements in the Rules, an APC is invoked by NEMMCO if the cumulative price over a rolling seven day period (i.e. 336 half hour trading intervals) exceeds the CPT, which is currently set at $150,000. This is equivalent to an average spot price of $446.43/MWh over seven days. If the average spot price for seven days is $32/MWh in a region, then subsequent VoLL prices (i.e. $10,000/MWh) for seven hours would be sufficient to exceed the CPT. Under the Rules, once the APC has been invoked by NEMMCO, the trading period becomes an APP. Once invoked the APP continues at least to the end of the current trading day at 4:00 am.

Clause 3.14.2 (c) of the Rules also indicates that an APP can also apply if:

- The sum of the ancillary service price for a market ancillary service in the previous 2016 dispatch intervals (equivalent to seven days) exceeds six times the CPT;

- The trading interval occurs in a trading day in which the prior trading interval was an APP; or
- The previous trading interval was an APP and NEMMCO believes that one or more trading intervals in the next business day will be an APP.

NEMMCO independently assesses and triggers administered price conditions for each region of the NEM. For all regions, the APC is currently set at $300/MWh for all time periods. It should be noted that the schedule for the APC was amended by the Commission on 21 May 2008.[2] Prior to this amendment, the APC was set for all regions at $100/MWh between 7:00 am and 11:00 pm during business days and $50/MWh at all other times. A discussion of the implications of this change to the APC schedule on EA's Rule change proposal can be found in Section 1.3.1 below.

Once a trading interval is classed as an APP, offer prices for energy and ancillary services cannot exceed the APC, and energy prices can not be less than the administered price floor, which is defined as the negative of the APC. Consequently, the trading interval spot price in an APP will only reach the APC, if each of the six dispatch interval prices in that trading interval is equal to or greater than the cap value.

1.2.6 How can Market Participants seek compensation following an administered price period?

The following parties may be eligible for compensation after an APP: Scheduled Generators; Scheduled Network Service Providers; Market Participants which submitted a dispatch bid; ancillary service generating units; and ancillary service loads. These Participants are eligible for compensation if their resultant spot price or receivable revenue during an APP was less than the price specified in their dispatch offer or bid for that trading interval. Claims for compensation must be submitted to both NEMMCO and the Commission within two business days of the trading interval when offer prices were adjusted or notification by NEMMCO that the APP or period of market suspension has ended.

Under clause 3.14.6 of the Rules, the Commission is responsible for determining whether it is appropriate for compensation to be paid by NEMMCO and the appropriate amount of compensation to be paid. Clause 3.14.6 of the Rules specifies that the Commission must establish a three member expert panel to provide recommendations to the Commission on the level of compensation payable. The expert panel is required to base its recommendations on an assessment of a "fair and reasonable" amount of compensation, and when making its assessment must take into account:

- All surrounding circumstances;
- The actions of NEMMCO and Registered Participant during the event; and
- The difference between the dispatch offer/bid price and the administered price.

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[2] AEMC, 2008, Final Determination: Clarification of Schedule for the Administered Price Cap, 21 May. Available at: http://www.aemc.gov.au/electricity.php?r=20071105.151356

Clause 3.14.6 of the Rules requires the expert panel to conduct itself on the same basis as a Dispute Resolution Panel. Clauses 8.2.6A to 8.2.6D of the Rules outline how Dispute Resolution Panels are required to operate.

1.2.7 Breach of the CPT and application of the APC in South Australia

The CPT was breached for the first time since the NEM commenced in SA on 17 March 2008. An APP was put in place by NEMMCO in SA from 5:30 pm on 17 March 2008 till 4:00 am on 19 March 2008.[3] See **Appendix E** for more information.

1.3 Linkages to other matters before the Commission

EA's Rule change proposal is linked to two other matters. Firstly, it is linked to the level of the APC, which has recently been adjusted by the Commission. Secondly, EA's Rule change proposal is linked to the level of VoLL and the CPT. Both of these will soon be reviewed by the Commission, following the AEMC Reliability Panel's December 2007 recommendation to increase the level of VoLL and the CPT in the Final Report of the Comprehensive Reliability Review (CRR).[4] These two matters and the nature of their linkages with EA's Rule change proposal are outlined below.

1.3.1 Determination of Schedule for the APC

The Commission published its Final Report on the 'Determination of Schedule for the Administered Price Cap' (the APC Schedule) on 20 May 2008. The APC Schedule sets out the APC that will apply in each region to spot prices and market ancillary service prices during an APP. As raised above, prior to the publication of this Final Report, the APC was set at $100/MWh between 7:00 am and 11:00 pm on business days and $50/MWh at all other times, for all regions and for both spot prices and market ancillary service prices.

The Commission's Final Report was published following consultation and set the APC at $300/MWh for all regions and at all time periods. In making its decision the Commission considered that an APC of $300/MWh is adequate in achieving a balance between meeting the competing objectives of being "sufficiently low to mitigate the risk of systemic financial collapse and sufficiently high not to distort the incentive for supplying electricity during an extreme market event when the APC is triggered".[5]

EA's proposal is linked to this Review as changes to the level of the APC may result in changes to the frequency of compensation payments following an APP and the total value of compensation payments sought. It can be expected that the higher the

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[3] NEMMCO, 2008, Pricing Event Reports- March 2008: 17 March 2008. Available at: http://www.nemmco.com.au/marketandsystemevents/pricing_mar.htm

[4] Reliability Panel, 2007, Final Report CRR, 21 December. Available at: http://www.aemc.gov.au/electricity.php?r=20051215.142656

[5] AEMC, 2008, Determination of Schedule for the Administered Price Cap- Final Report, 20 May, p. vii. Available at: http://www.aemc.gov.au/electricity.php?r=20071105.15135

APC, the less likely Market Participants will be to seek compensation, as the settlement payments arising from the APC are more likely to cover short run marginal costs and provide an adequate return to generators. This was recognised in the Commission's Final Report on the APC Schedule which notes that:

> "An APC level of $300/MWh is likely to mitigate the frequency and magnitude of compensation because: (a) the APC level is not significantly lower than the highest estimated SRMC in the NEM; and (b) the total generation capacity, with estimated SRMCs above the APC level, is assessed by the Commission to be minor compared to the total generation capacity in the NEM". [6]

1.3.2 Levels of VoLL and CPT Rule change proposal

The AEMC Reliability Panel released the Final Report of the CRR on 21 December 2007.[7] In this Report the Reliability Panel indicates that it intended to submit a Rule change package to the Commission to change the level of VoLL from $10,000/MWh to $12,500/MWh and the level of the CPT from $150,000 to $187,500. In outlining its reasoning for seeking these increases, the Reliability Panel indicates that market uncertainty regarding external policy settings, particularly in relation to greenhouse emissions and renewable energy, may affect the timing of generation investment needed to meet the reliability standard in the future.[8] In light of this uncertainty, the Reliability Panel considered that it would be prudent to "strengthen the reliability settings to increase confidence that the reliability standard will continue to be met in a timely manner, with additional generation coming online ahead of a potential breach of that standard in the future, especially for the period beyond 2011".[9]

Prior to submitting the Rule change package to the Commission, the Reliability Panel indicates in the Final Report of the CRR that it would publish an exposure draft of its Rule change proposal in April or May 2008, in order to gain stakeholder feedback on its recommendations. Subject to consultation, the Reliability Panel indicates that it would seek to submit its final Rule change proposal to the Commission in the second half of 2008, with the Rule change to have effect from 1 July 2010.[10]

EA's Rule change proposal is linked to the Reliability Panel's potential Rule changes because changes to the level of the CPT and VoLL, similar to changes to the APC, will alter the frequency of compensation payments. For instance, an increase in the level of VoLL and the CPT is likely to reduce the frequency of CPT breaches and accordingly the opportunities to claim compensation. Modelling by CRA International which was contained in Appendix E of the Final Report on the CRR supports this, and demonstrated that increasing the CPT level from $150,000 to

6 Ibid.

7 Reliability Panel, 2007, Final Report CRR, 21 December.

8 Reliability Panel, 2007, Final Report CRR, 21 December, p. xi.

9 Reliability Panel, 2007, Final Report CRR, 21 December, p. xii.

10 Reliability Panel, 2007, Final Report CRR, 21 December, p. xvii.

$200,000 was likely to result in a significant reduction in the incidence of CPT breaches each year.[11]

1.4 First round consultation

On 20 December 2007, the Commission issued a notice under Section 95 of the NEL, indicating its determination to initiate the Rule making process and first round consultation on EA's Rule change proposal. First round consultation closed on 22 February 2008.

The Commission received five first round consultation submissions from the following organisations:

- AGL Hydro Partnership and TRUenergy;
- The Energy Retailers Association of Australia (ERAA);
- Macquarie Generation;
- National Generators Forum (NGF); and
- NEMMCO.

Copies of these submissions are available on the Commission's website.

The main issues that were raised in submissions include:

- The eligibility for compensation;
- The financial risks for market participants under the current Rules; and
- How "direct generating costs" should be calculated.

These issues are discussed in further detail in **Appendix C**.

A number of specific amendments to the compensation provisions in the Rules were also proposed in submissions. For example, TRUenergy-AGL proposed increasing the time to submit compensation claims from two to five business days;[12] while NEMMCO proposed that the Rules should explicitly specify that the expert panel should only consider the costs incurred by generators over the APP when determining compensation.[13]

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[11] CRA International, 2007, 'Appendix E: Modeling Methodology, Input Assumptions and Results: Second Stage Modeling', *CRR,* December, p. 33.

[12] TRUenergy-AGL, 2008, First round submission, p.2.

[13] NEMMCO, 2008, First round submission, p. 2.

1.5 Consultancy reports commissioned by the Commission

The Commission's final Rule determination has also been informed by three consultancy reports. All three reports are available on the Commission's website. Where relevant, the key conclusions of these reports have been discussed in Chapter 3. These reports include:

1. Intelligent Energy Systems (IES), 'Regional Settlement Prices During Administered Pricing'.

This report was commissioned to provide technical advice on the impact of inter-regional flows on the operation of the APC and eligibility for compensation under clause 3.14.6 of the Rules. This report was published on the Commission's website on 29 May 2008.

2. Concept Economics, 'Risk Assessment of Alternative Compensation Options'

The report was commissioned to provide advice on the effect of three different compensation methodologies following administered pricing on the risks faced by different Market Participants. The three compensation methodologies that were examined by Concept Economics include:

- Compensation based on direct costs;
- Compensation based on direct costs and opportunity costs; and
- Compensation based on offer prices.

This report was published on 25 September 2008 on the Commission's website.

3. Concept Economics, 'Estimating Opportunity Cost for Energy Limited Plants'

This report was commissioned to provide advice on commonly used methodologies and guidelines to determine the opportunity costs of fuel limited plant, such as hydro and gas plant. This report also outlines examples from international electricity markets where calculations of opportunity cost are taken into account when resolving disputes between Market Participants.

This report was published on 25 September 2008 on the Commission's website.

1.6 Second round consultation

On 25 September 2008, the Commission gave notice under section 99 of the NEL of the making of the draft Rule determination and draft Rule.

The draft Rule and draft Rule determination were open for public consultation for six weeks. Submissions closed on 7 November 2008.

The Commission received two second round consultation submissions from the following organisations:

- ERAA; and
- Origin Energy.

Copies of these submissions are available on the Commission's website.

The main issues that were raised in the submissions include:

- The appropriateness of the draft Rule;
- The inclusion of opportunity costs in the compensation calculation; and
- The scaling of prices in adjoining regions.

The Commission also received comments, not in the form of a submission, in respect of:

- Specific methods for calculating opportunity cost; and
- Recovery of the Commission's administrative costs under the draft Rule.

These issues are discussed in further detail in **Appendix F**.

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2 The Commission's final Rule determination

The Commission has determined in accordance with Sections 102 and 103 of the NEL to make this final Rule determination and final Rule. The final Rule, which is different to the proposed Rule put forward by the proponent, can be found on the Commission's website**.**

This final Rule determination sets out the Commission's reasons for making the final Rule. The Commission has taken into account:

- The Commission's powers under the NEL to make the Rule;
- Relevant MCE statements of policy principles;
- The proponent's Rule change proposal and proposed Rule;
- First round stakeholder submissions;
- Consultancy reports commissioned by the Commission;
- The Commission's analysis as to the ways in which the Rule will or is likely to contribute to the achievement of the National Electricity Objective (NEO) so that it satisfies the statutory Rule making test.; and
- Second round stakeholder submissions.

2.1 The Commission's power to make the Rule

The subject matters about which the AEMC may make Rules are set out in Section 34 of the NEL and more specifically in Schedule 1 to the NEL.

The proposed Rule falls within the subject matters that the AEMC may make Rules about because it relates to the regulation of:

- The national electricity market (i.e. the Rules for the setting of prices for electricity and services purchased through the NEM); and
- The activities of persons participating in the NEM or involved in the operation of the national electricity system (as it involves the exchange of monies between different Market Participants for the purchase of electricity and services).

The Commission is satisfied that the proposed Rule is a matter about which the Commission may make a Rule.

Specifically, the Rule is also within matters set out in Schedule 1 to the NEL as it relates to:

- The setting of prices for electricity and services purchased through the wholesale exchange operated and administered by NEMMCO, including maximum and minimum prices (item 7 of Schedule 1 to the NEL);

- The methodology and formulae to be applied in setting prices referred to in item 7 (item 8 of Schedule 1 to the NEL);
- The operation of generating systems, transmission systems, distribution systems or other facilities (item 11 of Schedule 1 to the NEL); and
- The payment of money (including the payment of interest) for the settlement of transactions for electricity or services purchased or supplied through the wholesale exchange operated and administered by NEMMCO (item 34a of Schedule 1 to the NEL).

2.2 Relevant MCE statements of policy principles

Section 88 of the NEL requires the Commission to have regard to any relevant MCE statements of policy principles in applying the Rule making test. The Commission notes that currently there are no MCE statements of policy principles that relate to the issues contained in EA's Rule change proposal.

2.3 Assessment of the Rule: the Rule making test and the National Electricity Objective

2.3.1 The National Electricity Objective and the Rule making test

The NEO, which is the Commission's basis of assessment for considering Rule change proposals under the Rule making test, is set out in Section 7 of the NEL:

"The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system."[14]

The NEM Objective was renamed the NEO following amendments to the NEL, which commenced operation on 1 January 2008.

The Rule making test states:

(1) "The AEMC may only make a Rule if it satisfied that the Rule will or is likely to contribute to the achievement of the national electricity objective;

(2) For the purposes of subsection (1), the AEMC may give such weight to any aspect of the national electricity objective as it considers appropriate in all circumstances having regard to any relevant MCE statement of policy principles."[15]

[14] Section 7 of the National Electricity Law.

Under Section 91A of the NEL, the Commission is also able to make a "more preferable Rule"[16] that may be different, including materially different, from the market initiated proposed Rule. The Commission is able to make this more preferable Rule if it is satisfied that, having regard to the issue or issues raised by the proposed Rule, the more preferable Rule will or is likely to better contribute to the achievement of the NEO. The Commission's power to make a more preferable Rule commenced operation on 1 January 2008, following amendments to the NEL.

2.3.2 The EA Rule change proposal

EA provided a statement addressing how it considers its proposed Rule would or would be likely to contribute to the achievement of the NEO. In summary EA indicates that its proposal will contribute to the achievement of the NEO in the following ways:

1. Promote efficient investment in electricity generation by preserving the existing signals in the NEM which are established through the level of VoLL and the CPT/APP arrangements;

2. Promote efficient use of electricity generation capacity by ensuring efficient and secure dispatch during an APP, by removing the possibility of a pay as bid market;

3. Promote efficient investment in retail services by removing the possibility of extreme, unhedgeable compensation recovery charges being levied on retailers in the aftermath of an APP and in doing so reducing their risk exposure and cost of capital;

4. Promote efficient retail prices by reducing the amount of risk capital that a retailer must hold to maintain solvency during a worst-case scenario (for example the triggering of an APP);

5. Promote the long-term interests of consumers by removing the possibility of major disruption to customers and hardship in the aftermath of an APP which would result from retailers passing through the compensation costs to customers or from retailer insolvency; and

6. Ensure that the existing levels of reliability and security of electricity supply and the national electricity system are maintained by preserving the incentives for efficient generation investment and for generators to make generation capacity available for dispatch during an APP.

For these reasons, EA considers that its Rule change proposal has the potential to satisfy the Rule making test.

[15] Section 88 of the National Electricity Law.

[16] Section 91A of the National Electricity Law.

2.3.3 The Commission's approach and decision making framework

In assessing EA's Rule change proposal against the NEO, the Commission has also informed its decision by considering the following criteria:

1. The likely effect of the proposal on:
   - the economic efficiency of dispatch;
   - inter-regional trading and risk management;
   - pricing outcomes and participant responses;
   - power system security, supply reliability, and technical issues;
2. Whether the proposal is consistent with principles of good regulatory practice;
3. The likely long term implications of the proposal and its consistency with public policy settings; and
4. The likely timing and cost of the proposal and any other implementation issues.

In developing the final Rule determination, the Commission has also considered the events of 17 March 2008, when the CPT was breached in South Australia and administered pricing was applied from 17 March 2008 to 19 March 2008. As discussed in Chapter 1, this was the first time since the NEM commenced that the CPT was breached.

EA's Rule change proposal contains a number of hypotheses relating to how it considers market participants, particularly generation owners, are likely to act during an APP. Many of these hypotheses form the reasoning behind EA's Rule change proposal. The Commission notes that when EA was developing its Rule change proposal, that as the CPT had never been breached, EA did not have any data or information from an actual APP to draw upon, and consequently was required to base its Rule change proposal on speculating what might occur during an APP. The Commission also notes that as the consultation period for first round submissions closed on 22 February 2008, that first round submissions, like EA, would not have been able to benefit from the information and data from the breach of the CPT in South Australia on 17 March 2008. The Commission has taken these factors into account in considering EA's Rule change proposal and the first round submissions received.

The Commission views the breaching of the CPT in South Australia as an opportunity to examine the hypotheses in EA's Rule change proposal against real world events. The lessons learnt from this event are likely to strengthen the Commission's final Rule determination, and increase the likelihood that its Rule will be appropriate for the real world. However, in assessing this event, the Commission does note that a series of extreme events is required to trigger the CPT, and that as a consequence it is not possible to assume that Market Participants are likely to act in a similar way during every APP.

2.3.4 The Commission's assessment of the proposed Rule against the NEO

This section of the final Rule determination sets out the Commission's assessment of the EA Rule change proposal against the NEO.

EA Rule change proposals

1. **Seeks removal of the requirement for the expert panel to consider the difference between spot prices resulting from the APC and the Scheduled Generator's offer price; and**

2. **Confirmation that the objective of compensation to Scheduled Generators is to recover direct generating costs and that these costs should be specified**.

These two elements reflect the objective of EA's Rule change proposal to align compensation with a generator's costs as opposed to some other measure such as offer prices. In doing so the Rule change would contribute to the achievement of the NEO by promoting efficient investment in retail services, efficient retail prices and promoting the long term interests of end users of electricity.

An issue with EA's proposal is that their definition of costs is too narrowly defined, i.e. it is restricted to direct generating costs. This definition ignores other costs that form an important part of a firm's short run marginal cost, such as opportunity costs. By narrowly defining costs, the Rule change is likely to reduce the incentive for peaking generation assets and demand side bidders to provide services during an APP and would therefore reduce the reliability and security of the NEM. The restriction of compensation to direct generating costs also has the potential to reduce the incentive for investment in peaking generation assets.

The Commission considers that there is the potential to promote the NEO whilst maintaining the underlying motivation of the Rule change. The amended Rule change is addressed in the subsequent section.

3. **Require that the Commission publish the expert panel's report, its proposed compensation determination and invite submissions from interested parties for a period of 20 days prior to making a final determination.**

This Rule is likely to promote efficient investment in electricity services and regulatory certainty for the benefit of consumers by increasing the transparency and consistency in regulatory decisions.

The Commission supports this Rule change although it has made some minor additions to provide greater transparency and clarity. These additions are addressed in the subsequent section.

4. **Include a statement indicating that the Commission is required to take into account the expert panel's report, but is not bound by the panel's recommendations.**

The Commission considers that this element of the Rule change proposal is unlikely to contribute to the achievement of the NEO. The basis for the Commission's view is that the existing Rules already provide, perhaps in a more implicit manner, for the Commission to consider the expert panel's recommendation but to not be bound by the panel's recommendation.

2.4 Differences between the proposed Rule and the Draft Rule

The Commission has adopted some of EA's proposed Rule changes in part and proposes other Rule changes to address stakeholder issues, where they are shown to further promote the NEO.

The most significant amendment to EA's proposal is in regards to the methodology used to calculate compensation. The Commission supports the objective in EA's proposal to align compensation with costs and in doing so provide greater transparency in the compensation calculation. However the Commission considers that costs should be reflective of a firm's short run marginal cost and should therefore incorporate both direct generating costs and opportunity costs. The Commission also considers that the proposed methodology should be extended to all participants and not just Scheduled Generators.

The Commission also considers that there should be greater prescription in regards to how the expert panel conducts itself.

These amendments to EA's proposal are as follows:

- **Introducing the requirement that the Commission must develop compensation guidelines which the expert panel is required to follow when evaluating and calculating compensation claims; and**
- **The guidelines will specify:**

  - that the objective for compensation is to maintain the incentive for supplying electricity and other services during an APP and to maintain the incentive for investment in peaking generation assets;

  - a statement that compensation is to based on a participant's direct costs and opportunity costs;

  - the methodology to be used to calculate compensation, including defining direct generation costs and the approach to estimating opportunity costs;

  - detail the process and information gathering requirements to enable the calculation.

A number of minor changes have also been introduced to either build on EA's proposal or to address areas of existing uncertainty. These include:

- **Increasing the period in which participants can lodge a claim to five business days;**
- **Requiring that the Commission and expert panel's final reports must be published;**

- **Establishing the requisite time frame for each step in the compensation process (i.e. from the claim to the final determination), which must be no more than 150 business days in total; and**
- **Establishing that the cost of assessing compensation claims should be deduced from any eventual payment from the applicant if the claim was unsuccessful.**

Detailed reasoning and the Commission's response to submissions are set out in **Appendix A**.

2.5 Differences between the draft Rule and the Rule to be made

The Commission received two second round submissions on the draft Rule and draft Rule determination. Both submissions were supportive of the draft Rule. However, the ERAA expressed concern that the process for determining the opportunity costs included in compensation is open ended, and should be reconsidered by the Commission. The Commission has reconsidered its proposed approach and is of the view that the compensation guidelines in the Rule will address these concerns by providing guidance on the methodology to be used to calculate opportunity costs. Stakeholders will be able to comment on the methodology as part of the development of the guidelines.

Origin Energy requested that greater consideration be given to the IES proposal to restrict the application of APP to regions where the CPT has been breached. However, the Commission considers that this change would require further consideration and that it would be more appropriate for such consideration to be given through a separate Rule change proposal.

The Commission has therefore not made any changes to the draft Rule.

2.6 Rule Commencement

The final Rule is scheduled to commence on 1 January 2009.

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A Commission's analysis of the Proposed Rule

In this appendix, the Commission addresses a number of issues that were raised in submissions or that have emerged during its analysis. In summary there are seven key issues that the Commission has examined:

- Restriction of cost based compensation following administered pricing to Scheduled Generators;
- Impact of interregional flows on the operation of the APC and eligibility for compensation;
- An assessment of EA's proposed methodology for calculating compensation based on direct generating costs;
- An assessment of other methodologies for calculating compensation;
- The practicalities of implementing compensation based on direct costs and opportunity costs;
- The process for determining compensation; and
- Funding of the compensation determination process.

This section details the Commission's analysis and reasons underlying its Draft Rule in relation to each of the above issues.

A.1 Restriction of cost based compensation to Scheduled Generators

A.1.1 Existing arrangement

Under clause 3.14.6 of the Rules, Scheduled Generators, scheduled network service providers, Market Participants, and ancillary service generating units and loads are all eligible to claim compensation following administered pricing. The process for evaluating and calculating compensation is similar for all participants.

A.1.2 EA's proposal

EA's rule change proposal seeks to restrict compensation for Scheduled Generators to only their direct generating costs. EA's proposed Rule indicates that these "direct generating costs" will include:

- Fuel costs in connection with the scheduled generating unit;
- Incremental maintenance costs in connection with the scheduled generating unit; and
- Incremental manning costs in connection with the scheduled generating unit.

Therefore, if EA's proposed Rule was adopted, compensation for Scheduled Network Service Providers, Market Participants, and ancillary service generating units and loads would still be determined by the expert panel under the current criteria in clause 3.14.6 of the Rules.

EA indicates in its Rule change proposal that it is seeking to restrict its proposed changes to the way compensation is determined for Scheduled Generators only, because:

- "MNSP [Market Network Service Providers] and demand-side bidder sectors are relatively small and so the materiality of compensation uncertainty is commensurately lower; and
- Determination of MNSP and demand-side bidder direct costs may be more complex than determination of generator direct costs".[17]

However, EA also indicates that it would not object to extending its proposed changes to MNSPs and demand side bidders if this was found to be "appropriate" by the Commission.[18]

A.1.3 Views of first round submissions

The majority of first round submissions received highlighted concerns over EA's proposal to restrict its changes to the compensation provisions following administered pricing to Scheduled Generators only.

NEMMCO, TRUenergy-AGL, and Energy Retailers Association of Australia (ERAA) supports extending EA's Rule change proposal to the other categories of participants currently eligible to claim compensation under clause 3.14.6 of the Rules. NEMMCO and ERAA indicates this would ensure consistency in the Rules. TRUenergy–AGL considers that EA's reasoning for excluding these other categories of Participants is flawed because:

- MNSPs are able to claim compensation under a greater number of circumstances than Scheduled Generators; and
- The direct costs of MNSPs and ancillary service generating units and loads are relatively simple to discern as they are externally assessable from NEMMCO data.

NEMMCO's submission also proposes restricting compensation to Market Scheduled Generators and MNSPs; rather than all Scheduled Generators and Scheduled Network Service Providers, as is currently provided for under clause 3.14.6 of the Rules. NEMMCO reasons that only the Market Scheduled category of Participants are required to operate in accordance with the central dispatch process and are paid consistent with that process unless their offers are priced above the APC.[19]

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[17] EneryAustralia, 2007, Compensation arrangements under administered pricing Rule change proposal, 10 December, p. 13.

[18] Ibid.

[19] NEMMCO, 2008. Compensation arrangements under administered pricing Rule change proposal- First round submission, p. 1.

A.1.4 The Commission's consideration and reasoning

The Commission considers that EA's proposed changes to the compensation provisions should not be restricted to Scheduled Generators only. The Commission does however support NEMMCO's proposal to restrict compensation to Market Scheduled Generators and MNSPs and exclude non-market participants.

The Commission has two reasons for these views.

Firstly, like Scheduled Generators, other Market Scheduled participants such as MNSPs and ancillary service generators affect the dispatch process used to determine the dispatch volumes of Market Participants and the regional reference price (RRP). Under the NEM's security constrained dispatch process, implied nodal prices determine the dispatch volumes of each Participant, and these Participants behave in the expectation that they will be settled for their dispatch volumes at the resulting RRP.

When an APC over-rides the RRP resulting from the dispatch process, the spot market settlement positions of *all* Market Scheduled Participants (i.e. market Scheduled Generators, MNSPs and ancillary service generators) are affected because the settlement price changes from one based on the RRP to one based on the APC.[20] Non-market participants however are not disadvantaged by the APC as they do not receive market payments and similarly non-scheduled participants can operate their plant independently of the dispatch process. Therefore, the Commission is not persuaded by EA's reasoning for limiting cost based compensation to Scheduled Generators only.

Secondly, the extension of EA's Rule change proposal to all Market Scheduled Participants will also provide greater consistency to the Rules, because it will mean that all Market Scheduled Participants are compensated on the same basis, rather than having Scheduled Generators treated differently to other classes of Participants. The Commission suggests that this change will provide greater confidence and certainty to Participants regarding how their claims for compensation following administered pricing will be assessed, which should lead to greater dispatch efficiency and supply reliability during APPs. The Commission also considers that it is good regulatory practice to ensure that the Rules are as consistent as possible for different categories of Participants.

The Commission has determined that the proposed changes to the methodology used to calculate compensation should be applied not just to Scheduled Generators, but all Market Scheduled Participants.

This will be reflected in the guidelines which will set out the methodology that the expert panel must follow when calculating compensation for Market Scheduled Generators and MNSPs.

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20 The dispatch volumes of each Participant at each location continue to be determined with reference to the nodal price, which is a function of the bids and offers at that location and any binding constraints, which are affected by changes in the level of generation or load across the network.

A.2 Impact of inter-regional flows on the operation of the APC and eligibility for compensation

In assessing the possible impacts of EA's Rule change proposal on the NEM and its Participants, the Commission has also investigated the impact of inter-regional flows on the operation of the APC and eligibility for compensation under clause 3.14.6 of the Rules.

This issue was raised in TRUenergy-AGL's first round submission, which highlights the complexities of forecasting the operation of the APC under the current Rules as a source of potential risk and uncertainty. This is because the application of the APC is affected by inter-regional flow direction.[21] The Commission also considers that the impact of inter-regional flows during an APP may increase the number of eligible participants who are able to claim compensation following administered pricing. A summary of the Commission's assessment of the impact of inter-regional flows on eligibility for compensation under clause 3.14.6 of the Rules is below. This issue is also discussed in further detail in **Appendix D**.

The Commission's assessment of this issue has been informed by a consultancy report by Intelligent Energy Systems (IES), 'Regional Settlement Prices During Administered Pricing', which outlines the operation and effect of price scaling during APPs. This report was published on 29 May 2008 and is available on the Commission's website.[22]

A.2.1 How do inter-regional flows affect the operation of the APC?

Following a breach of the CPT in a region, the APC will be applied in that region by NEMMCO and the APP will continue at least until the end of the current trading day at 4:00 am.

However, the application of the APC in one region can also result in the scaling back of prices in adjoining regions.

Clause 3.14.2(e)(2) of the Rules indicates that the price of regions where the APC has not been applied will be scaled back if these regions have energy flowing along regulated interconnectors towards a region where the APC has been applied. Clause 3.14.2(e)(2) outlines that the RRP of the exporting region will be scaled back to the product of:

- The importing region's capped price; and
- The average inter-regional loss factor between the exporting region and the importing region.

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21 TRUenergy-AGL, 2008, Compensation arrangements under administered pricing Rule change proposal- First round submission, p. 1.

22 IES', 2008, 'Regional Settlement Prices During Administered Pricing', 29 May. Available at: http://www.aemc.gov.au/pdfs/reviews/Compensation%20Arrangements%20Under%20Administered%20Pricing/supplementary/000IES%20Final%20Report%20-%20Regional%20Settlement%20Prices%20during%20Administered%20Pricing%20-%20May%202008.pdf

The effect of clause 3.14.2(e)(2) is to drive down the settlement price in a region to which the APC is not being applied, from the level it would have otherwise been. In other words, the direct application of an APC in one region in which the CPT has been breached can result in the indirect imposition of an administered price in an adjoining region in which the CPT might not have been breached. As a consequence, during an APP, price capping may occur in a number of regions and may not be isolated to the region where the APC has been directly applied.

A.2.2 What is the effect of price scaling on eligibility for compensation under clause 3.14.6 of the Rules?

The Commission considers that the wording in clause 3.14.6(a)-(a3) of the Rules is sufficiently broad to enable Participants in interconnected regions where the APC has not been directly applied, to seek compensation following an APP if their resultant spot price/revenue is less than the price specified in their dispatch offer/bid for that particular trading interval. EA did not refer to clause 3.14.2(e)(2) in its Rule change proposal; nor did seek to amend this clause in its proposed Rule in Appendix 2 of its proposal. It is unclear whether this omission is deliberate, or whether EA was unaware of clause 3.14.2(e)(2) and the impact it may have on eligibility for compensation following administered pricing.

The Commission's interpretation of clauses 3.14.2(e)(2) and 3.14.6 of the Rules and the interaction between them is material to EA's Rule change proposal. This is because an increase in the number of eligible Participants for compensation will also naturally increase the potential size of any compensation payment and the financial risks of retailers who are required to fund these compensation payments. Moreover, the financial risks arising from compensation uplift payments would potentially be spread to retailers operating in regions other than the one to which the APC has been directly applied.

A.2.3 What is the Commission's reasoning for its position on the effect of price scaling on eligibility for compensation?

The application of clause 3.14.2(e)(2) of the Rules may result in Participants in an interconnected region being dispatched when their dispatch offer price exceeds the adjusted settlement price (i.e. the administered price, be that the APC or a scaled price based on the APC). Participants in regions where the APC has been directly imposed and Participants in interconnected regions are both potentially affected by the application of the APC. The Commission therefore considers that there is no reason for discriminating the payment of compensation between these two classes of Participants merely on the basis of their location. Further, the average inter-regional loss factor that is applied to the APC is generally likely to be a positive value less than one. It is therefore likely that Participants in regions where the APC has not been directly applied may receive lower settlement prices than Participants in regions where the APC has been directly applied.[23]

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[23] In some instances, an average loss factor can have a negative value, resulting in the scaled price in a region which is exporting power to an APC affected region, exceeding the APC in the importing

In addition clause 3.15.10 of the Rules sets out the provisions for the payment of compensation by Market Customers following administered pricing. The Commission considers that the language of this clause is sufficiently broad to impose a compensation-funding obligation on Market Customers who purchased electricity in an interconnected region. Clause 3.15.10 indicates that Market Customers who purchased electricity from a region "affected" by the APC are required to pay compensation. These Market Customers would have benefited from reduced prices in their region, so it is consistent that they should also have the obligation to pay compensation to those Participants located in their region who received reduced settlement prices.

A.2.4 An alternative to price scaling during APPs?

IES indicates that EA's proposal to minimise the magnitude of potential compensation payments by limiting compensation to Scheduled Generators' "direct generating costs" may not be the most efficient way to reduce retailers' financial risks.

Rather, IES suggests that an alternative option to limit the magnitude of potential compensation payments could be to remove price scaling during APPs.[24] Under IES' proposal, the APC would only be applied in the region where the CPT had been breached and negative inter-regional settlement residues (IRSR) would be allowed to accrue on interconnecters between the APC affected region and other connected regions. IES suggests that IRSR unit holders could then be compensated for any reduction in residue payments as a result of the APC through:

- The existing compensation provisions in clause 3.14.6 of the Rules; or
- Payments by customers in the importing (i.e. APC affected) region.

Participants in the region where the APC had been directly applied would also be eligible for compensation under the existing compensation provisions.

IES indicates that this approach has been used previously under a Victorian jurisdictional derogation to the National Electricity Code between 1998 and 2001. Under this derogation, an Industrial Relations Force Majeure (IRFM) period could be declared following industrial strikes, which would lead to the imposition of an APC in the Victoria region. Negative IRSRs arising from the IRFM period were then recovered from Victorian retailers.[25] This created so-called "white-hole uplift" settlement payment obligations for Victorian retailers during 2000, following the declaration of an IRFM period during an industrial relations dispute at Yallourn Energy.[26]

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region. For further information on how this can occur see p.18 in IES, 2008, 'Regional Settlement Prices During Administered Pricing', 29 May.

[24] IES', 2008, 'Regional Settlement Prices During Administered Pricing', 29 May, p. 20-21.

[25] Chapter 9A1.1(8), National Electricity Code.

[26] Office of the Regulator –General Victoria, 2000, 'Final Approach: Retailing Change in Taxes (White Hole Up Lift) Determination', December.

IES notes that this alternative proposal could be considered by the Commission under its power to make a more preferable Rule under Section 91A of the National Electricity Law.

IES indicates that this alternative option may result in compensation payments that are smaller than those under the existing Rules and under EA's proposed Rules.

A.2.5 The Commission's consideration of IES' proposal

The Commission notes that the intent of price scaling during APPs is to limit the accrual of large negative IRSRs.[27] The Commission considers that large negative IRSRs are not desirable, but that price scaling during APPs may not be the most efficient method of reducing negative IRSRs. This is because there is the potential for price scaling to alter the RRPs of multiple regions across the NEM where the CPT may not have been breached. The objective of the CPT and APC arrangements is to mitigate risk following periods of prolonged high prices. The application of scaled prices may therefore not be appropriate in regions where the CPT has not been breached.

As discussed above, price scaling during APPs also increases the number of eligible Participants who can claim compensation following administered pricing, and the resulting size of any compensation payment. This may cause uplift payments for a number of retailers across the NEM. End use customers in multiple regions may also have to fund their share of any uplift payment, depending on the type of contract they have with their retailer.

The Commission considers that IES' proposal to remove price scaling during APPs has merit and that it may reduce the size and magnitude of compensation payments following administered pricing, and the consequential financial risks for retailers from such a payment. However, the Commission has determined not to remove price scaling in its draft Rule under its power to make a more preferable Rule under Section 91A of the NEL. The Commission considers that such a change to the Rules would require further investigation and consultation to examine the potential consequences of this change, and that the appropriate vehicle for this investigation is a separate Rule change proposal.

The Commission has not made an amendment to the Rules in regards to the impact of inter-regional flows.

27 Code Change Panel, 2000, 'VoLL scaling report, March, p.2. Available at: http://www.neca.com.au/TheCode4827.html?CategoryID=34&SubCategoryID=83-

A.3 Compensation based on direct generating costs

A.3.1 Existing arrangement

Clause 3.14.6 of the Rules provides the expert panel and the Commission broad discretion when determining if compensation should be awarded and if so, the appropriate amount.

Clause 3.14.6(e) of the Rules requires the expert panel to base its recommendations to the Commission on its assessment of a "fair and reasonable" amount of compensation. This must take into account:

1. All of the surrounding circumstances;
2. The actions of any *Registered Participants* and *NEMMCO*; and
3. The difference between the dispatch offer/bid price and the administered price of the claimant.

A.3.2 EA's proposal – compensation based on direct generating costs

EA's Rule change proposal seeks to limit compensation following administered pricing for Scheduled Generators to their "direct generating costs".

To achieve this EA seeks to include a statement in the Rules specifying that the purpose of any compensation payment is to recover direct generating costs incurred by dispatched generating units during an APP. EA's proposed Rule also outlines the direct generating costs that Scheduled Generators will be able to claim compensation against. These direct generating costs include:

- Fuel costs in connection with the scheduled generating unit;
- Incremental maintenance costs in connection with the scheduled generating unit; and
- Incremental manning costs in connection with the scheduled generating unit.

It should also be noted that under EA's proposed Rule, Scheduled Generators would only be eligible to claim compensation, if they are able to demonstrate that their direct generating costs, as outlined above, were greater than the administered price (i.e. APC or scaled price) they received. Therefore, under EA's proposed Rule, Scheduled Generators with direct generating costs below the APC or scaled price would not be eligible for compensation following administered pricing.

A.3.3 Views of first round submissions on EA's proposal

TRUenergy–AGL and ERAA both suggest in their submissions that EA's Rule change proposal would reduce the risk of large and unhedgable compensation "uplift" payments for retailers. TRUenergy–AGL indicates that this would occur by clarifying what compensation a generator is entitled to and “removing any suggestion of opportunity for extra-normal profits”[28] in the Rules.

However, submissions from TRUenergy–AGL, ERAA, the NGF and Macquarie Generation all suggest that EA’s proposed list of “direct generating costs” would make it difficult for the opportunity costs of generation to be taken into account by the expert panel, and that as a consequence EA has not recognised the complexities of calculating the “direct generating costs” of hydro and gas generators.

In relation to the potential opportunity costs of gas generators, Macquarie Generation suggests that, “increased production may result in the accelerated use of contracted gas supplies. This could result in lower gas availability during later dispatch periods when prices are no longer capped”.[29] Macquarie Generation also suggests that this could result in higher prices for gas supply and transportation when contracts are renegotiated. The NGF also indicates that the ”relatively shallow and dynamically priced gas market”,[30] would make it difficult for gas operators to quantify their fuel costs when applying for compensation.

The NGF and Macquarie Generation suggest that even coal plants have some implicit and indeterminate incremental maintenance and fuel costs, which would not be taken into account under EA’s list of “direct generating costs”. For example, Macquarie Generation indicates that operating a coal plant between 95% and 105% capacity will accelerate future wear and tear and “will limit plant availability and operating revenues in future periods when outages are brought forward”.[31]

The potential impact of EA’s Rule change proposal on supply reliability during APPs was also highlighted by the NGF and Macquarie Generation. Submissions from the NGF and Macquarie Generation indicates that limiting the compensation of Scheduled Generators to EA’s list of “direct generating costs” may reduce generators’ incentives to generate at a time when they are most needed, that is, during an APP, when demand is likely to be tight and when there may be risks to system security and reliability. The NGF suggests that this may lead to a situation where generators may choose to be directed by NEMMCO rather than voluntarily participate in the dispatch process during an APP, as there are “clear precedents of generator compensation”[32] following NEMMCO directions. An outline of the compensation provisions for Directed Participants under clause 3.15.7 of the Rules is detailed in **Box 1** below.

28 TRU Energy/AG:, 2008, First round submission- Compensation under administered pricing, p. 1.

29 Ibid.

30 NGF, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 1.

31 Macquarie Generation, 2008. First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 2.

32 NGF, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 1.

Box 1- Compensation arrangements for Directed Participants for the provision of energy or market ancillary services

Compensation for Directed Participants is set out in clause 3.15.7 of the Rules. This clause indicates that Directed Participants are entitled to compensation based on the following formulae:

*Compensation to Directed Participant = AMP * DQ*

Where:

AMP= the price at the 90th percentile of the spot prices/market ancillary service prices for the relevant service in that region for the previous 12 months; and

DQ= either:

(A) the difference between the amount of energy that was consumed/delivered by the Directed Participant and the amount of energy that would have been consumed/delivered had the direction not been issued; or

(B) the amount of the relevant market ancillary service which the Directed Participant was required to provide in response to the direction.

If when NEMMCO issues the direction, the Directed Participant had submitted a valid dispatch bid or offer, the Participant is entitled to receive compensation equal to the price in that dispatch bid or offer for the service provided.

It should be noted that Macquarie Generation's submission was submitted prior to the Commission's May 2008 decision to increase the APC. In their submission Macquarie Generation indicates that increasing the level of the APC may reduce the need for generators to seek compensation following administered pricing. Macquarie Generation notes that setting the APC at a level that covered the cost of marginal generating plants in most circumstances would encourage generator participation during APPs. This would significantly reduce the likelihood that generators would need to recover losses through the compensation process.

A.3.4 Concept economics assessment of alternative compensation options

The Commission's assessment of EA's proposed methodology for the determination of compensation has been informed by Concept Economics assessment of the following:

- The risks following administered pricing for different types of Participants; and
- The Alternative Compensation Options;

A.3.4.1 The risk impacts of compensation following administered pricing for different types of Participants

The Commission notes that the risks associated with compensation following administered pricing differ depending on the type of Participant. Therefore changes to the methodology used to determine compensation can alter the magnitude of risk for different classes of Participants. This feature requires the Commission to make a judgement as to how the competing risks of different types of Participants should be balanced to provide the most effective outcome for the market as a whole.

To better understand the different types of risks associated with compensation following administered pricing and to understand the alternative compensation options, Concept Economics was commissioned to examine the issues.

Based on the Concept Economics report, retailers are likely to be exposed to risks from the compensation provisions associated with administered pricing due to the following:

- The methodology that is used to determine compensation affects the magnitude and volatility of compensation payments, and the corresponding financial risks for retailers from any uplift payment they must pay. However, irrespective of the compensation methodology employed the magnitude of any compensation payment following administered pricing is always uncertain as it depends on many factors (e.g. the discretion of the Commission and recommendations of the expert panel; the type and cost of generators which are dispatched during the APP, the willingness of Participants to apply for compensation following an APP etc);
- Retailers are unable to hedge against potential compensation payments as their hedge contracts will be referenced to the regional spot price which will be reflected by the capped price rather than a compensation payment;
- As an APP will only be put in place following an extended period of price volatility, retailers may already be under financial stress prior to the application of the APP. Therefore, a potentially large and unhedged compensation payment may lead to a significant cash flow risk for retailers in the short term; and
- In the long term retailers may be required to absorb a large proportion of their share of compensation payments, as retailers may be unable to pass on the costs of any compensation payment to their customers. The ability of retailers to pass through costs will depend on the type of contract they have with their customers and the regulatory framework of the jurisdiction(s) that they are operating in. [33]

In contrast, Concept Economics suggests that compensation following administered pricing may impact generators in the following ways:

- A generator may be constrained on during an APP and receive a price which is below its short run marginal cost;
- Generators may face opportunity costs as a consequence of being constrained on during an APP. For example, generators may be required to operate at a capacity which may not be technically efficient and may incur additional operational and maintenance costs as a result. Fuel limited plant such as hydro and gas plants which operate during an APP may have to forgo opportunities to generate at a future time when the spot price may be significantly higher; and

33 Concept Economics, 2008, 'Risk Assessment of Alternative Compensation Options', p. 10.

- Generators which apply for compensation following an APP may face significant delays in the processing of their compensation claims. There is also considerable uncertainty for generators concerning the level of compensation that will be awarded. [34]

Concept Economics also suggests that demand side bidders will face revenue risks which are similar to those faced by generators, as the APP may significantly diminish the revenues they are able to earn.[35] Concept Economics estimates that the marginal cost of demand side measures may range up to $3000/MWh.[36]

Concept Economics also discusses the impact of compensation following administered pricing for network service providers, which is based on the difference in rent collected on the interconnector between capped and uncapped prices. Concept Economics notes that if high prices are concentrated in a single region, then there is the potential for high compensation payments because there will be a large price differential between regions. However, if price scaling is applied to multiple regions, then compensation may be relatively low due to the smaller price differential between regions.[37]

A.3.4.2 Risk Assessment of Alternative Compensation Options

In the report titled 'Risk Assessment of Alternative Compensation Options', Concept Economics assesses the impact of three different compensation methodologies following administered pricing on the financial risks faced by different Market Participants. These three compensation methodologies are:

1. Compensation based on "direct operating costs", i.e. short run marginal costs but excluding opportunity costs;

2. Compensation based on short run marginal costs, including opportunity costs; and

3. Compensation based on the bids and offers of Market Participants.

Modelling of the impacts of each of these compensation methodologies is based on two recent high price events when the CPT was breached or nearly breached. These events include:

1. 11 to 17 March 2008 in SA, when the CPT was breached on 17 March; and

2. 12 to 18 June 2008 in NSW, when the rolling seven day cumulative price exceeded $120,000.

A summary table by Concept Economics outlining the key impacts of each compensation methodology can be found in Table 1 below.

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[34] Ibid.

[35] Ibid.

[36] Concept Economics, 2008, 'Risk Assessment of Alternative Compensation Options', p. 29.

[37] Concept Economics, 2008, 'Risk Assessment of Alternative Compensation Options', p. 32.

Table 1- Concept Economics' summary of the impact of different compensation methodologies

Option	Information Needed	Issues
Direct operating costs only	Fuel and variable operating cost estimates	Lower bound on compensation payment. Easy to implement, transparent and provides certainty on cost. Does not recover fixed costs. Does not consider opportunity costs – problematic for limited energy plants such as hydro.
Direct operating costs and opportunity costs	Estimates of opportunity costs will require complex analysis and related resolution of data and process issues	Theoretically sound option but complex and may lack transparency. Opportunity cost estimates may vary substantially – in theory from zero up to VoLL – creating risks for retailers and revenue uncertainty for generators. Since the portfolio of contracts that retailers hold are linked to market prices only, retailers are potentially exposed to large and uncertain uplifts that cannot be hedged. If significant, such risks may lead to systemic market-wide risk. Some components of opportunity costs, such as additional costs associated with wear and tear, sourcing fuel and changing maintenance plans, may be difficult to quantify.
Offer price	Bid and offer data	Easy to implement. Offer prices during an administered price period may be high, creating a risk for energy purchasers – potentially yielding the highest compensation payments. Again, large and uncertain uplifts that cannot be hedged by retailers may lead to systemic market-wide risk.

Source: Concept Economics, 2008, 'Risk Assessment of Alternative Compensation Options, p. 37.

Concept Economics' report is available on the Commission's website and was published on 25 September 2008.

A.3.5 The Commission's assessment of EA's proposed compensation methodology

The Commission considers that the current criteria used for the determination of compensation following administered pricing lacks clarity and transparency. This may contribute to market uncertainty in relation to how the expert panel and the Commission assess compensation claims. The Commission suggests that this market uncertainty may influence the bidding behaviour of Market Participants during APPs in an unpredictable manner and may lead to dispatch inefficiency and reduced supply reliability. Therefore, the Commission considers that greater prescription in the Rules regarding how compensation following administered pricing will be determined is necessary and warranted.

Modelling by Concept Economics in its 'Risk Assessment of Alternative Compensation Options' suggests that of the three options it has investigated, compensation based on direct costs will result in the lowest level of compensation payable and is the most transparent way of calculating compensation. Basing compensation on direct costs is also relatively easy to implement and provides some certainty in relation to how compensation will be determined following an APP.

However, Concept Economics has also voiced the same concerns that were raised in first round submissions regarding opportunity costs. That is if opportunity costs are not recognised it would be difficult to apply the methodology to fuel limited plants such as hydro power stations, where opportunity costs may comprise a significant share of total costs. In addition other opportunity costs such as the opportunity costs associated with deferring maintenance would not be recognised under this methodology.

Therefore, Concept Economics suggests that although compensation based on direct costs may be effective in mitigating the financial risks of retailers following an APP, it may discourage generators and demand-side bidders from providing their services to the market during an APP. Concept Economics also suggests that in the long term, if APPs are frequent, compensation based on direct costs may also discourage investment in generation and in demand side response.

The Commission considers that maintaining the incentive for generators and demand-side bidders to provide their services during an APP is vital. This is because the objective of the APP arrangements is to mitigate market wide risk and instability following a period of prolonged high prices. The Commission believes that basing compensation following administered pricing on direct costs, may not be the most effective way to ensure that supply reliability and market stability are maintained during an APP.

Further, the Commission also notes that the NGF indicates in its submission that if compensation is based on direct costs, Participants may choose to be directed by NEMMCO rather than voluntarily participating in the dispatch process during an APP, because there are clear precedents for compensation following directions.

As outlined in **Box 1** above, compensation following directions under clause 3.15.7 of the Rules is based on either:

- Prices in the 90th percentile of the spot prices/market ancillary service prices for the relevant service in that region for the previous 12 months; or
- The Participant's bid/offer if the Participant had submitted a valid dispatch bid or offer for the service at the time the direction was issued.

The Commission considers that in the majority of circumstances that either of these methodologies is likely to yield compensation above the direct costs of Participants. As a result, the Commission considers that a compensation regime following administered pricing that is based on direct costs, may create a perverse incentive for Participants to "venue shop", by behaving in ways that ensure that they can claim compensation under the provisions which are most financially favourable. The Commission suggests that this may create dispatch inefficiency and may lead to reduced supply reliability and market instability.

Therefore, whilst the Commission acknowledges that compensation based on direct costs will result in relatively low compensation payments, the Commission has decided not to adopt EA's proposal to base compensation following administered pricing on the direct operating costs of Participants.

Under Section 91A of the NEL, the Commission has the power to make a "more preferable Rule", which may be different, including materially different, from the market initiated proposed Rule. The Commission is able to make this more preferable Rule if the Commission is satisfied that, having regard to the issue or issues raised by the proposed Rule, the more preferable Rule will or is likely to better contribute to the achievement of the NEO.

Therefore the Commission proposes to make a more preferable Rule in regards to the methodology for determining compensation. This is discussed in the subsequent section.

The Commission considers that compensation should not be based on direct generating costs alone.

A.4 Commission's more preferable Rule - alternative methodologies for the determination of compensation

The Commission considers that the current compensation provisions in clause 3.14.6 of the Rules should be revised to provide Participants with greater clarity and transparency in terms of how compensation will be determined. However, the Commission has also decided to reject EA's proposal to base compensation following administered pricing on the direct costs of the claimant.

Therefore, under its power to make a more preferable Rule, the Commission has investigated two other methodologies for the determination of compensation following administered pricing:

1. Compensation based on bids and offers of Participants (known as offer based compensation); and

2. Compensation based on the direct costs and opportunity costs of Participants.

These two methodologies and the Commission's assessment of them are discussed below.

A.4.1 Offer based compensation

Concept Economics highlights that the bids and offers of Participants "ultimately reflect the commercial position of the generator, including any return needed on its long term investments as well as any economic opportunity costs".[38]

A compensation regime that is based on the bids and offers of Participants would effectively compensate claimants for the difference between the capped price they received during the APP (i.e. APC or scaled price) and the bid or offer price they submitted to NEMMCO. However, it should be noted that Participants would only be eligible for compensation under this regime if they:

(a) Were dispatched during the APP; and

(b) Had submitted valid dispatch bids/offers that were higher than the capped price they received.

A.4.1.1 EA's Proposal

In its Rule change proposal, EA discusses offer based compensation on the basis that the existing arrangements may result in the expert panel adopting it for their compensation recommendations.

EA suggests that using a generator's offer price as a basis for calculating compensation would increase the level of market risk, contrary to the original intent of the CPT and APP arrangements.

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38 Concept Economics, 2008. Risk Assessment of Alternative Compensation Options, p.12.

Accordingly EA considers that offer based compensation will affect market behaviour and outcomes in ways not envisaged or intended by the Rule designers. This is due to the fact that it renders the capping of the spot price ineffectual and may give rise to high levels of compensation equivalent to the difference between the generator's capped spot price and their offer price. EA proposes that this may lead to a "pay as bid" compensation regime.

EA considers that pay as bid compensation may result in generators basing their offers to NEMMCO during an APP not on their costs, but on what each generator forecasts the future clearing price will be, so they will be dispatched and be able to claim compensation. EA suggests that this may lead to higher dispatch costs, lower dispatch efficiency and may jeopardise system security and reliability.

A.4.1.2 Views of first round submissions on offer based compensation

Submissions from Macquarie Generation and the NGF disputes EA's claim that the current compensation provisions would create a potential "pay as bid" scenario and render the risk management mechanisms of the APC and CPT ineffective.

Macquarie Generation suggests that in practice generators face the risk that their competitors will offer lower priced output to the market to cover contract positions or earn spot revenue, and notes that generators who are not dispatched will not be eligible for compensation.[39] The NGF describes the "pay as bid" scenario as an "extreme hypothetical" scenario but also notes that the objective of the compensation provisions is not to provide generators with compensation equivalent to their offer prices. [40]

The NGF suggests that to reduce concern regarding a "pay as bid" scenario, the current compensation provisions should be amended to allow the expert panel to consider changes to dispatch offers co-incident to the application of the APC.[41] Macquarie Generation indicates support for the NGF proposal in its submission.

A.4.1.3 Concept economics assessment of offer based compensation

Concept Economics suggests that of the three options it investigated, compensation based on the bids and offers of claimants is likely to result in the highest compensation payments, and that payments under this regime would also be significantly more volatile and variable than compensation based on direct costs.

In providing this opinion, Concept Economics analysed the three compensation options on simulations of the high price periods over March 2008 in South Australia, when the CPT was breached. Concept Economics indicates that in its simulations of this period, the average compensation calculation using cleared generator bids was

39 Macquarie Generation, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 1.

40 NGF, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 1.

41 NGF, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 2.

approximately $914,000 over a one week period, although results ranged from approximately $78,000 up to $2 million.[42] In contrast, the average compensation calculation based on direct generating costs was $78,000, and the highest result for this type of compensation was just over $100,000.[43] These simulations were based on an APC of $100/MWh, however Concept Economics suggests that an APC of $300/MWh would not change any of the general conclusions that it reached.[44]

Concept Economics also indicates, similarly to EA, that compensation based on offer prices also provides generators with an incentive to alter their bids and offers during an APP. Concept Economics suggests that "it may lead to high bids/offers and, at the extreme, may effectively negate the purpose of a CPT".[45] Therefore, Concept Economics considers that measures to limit the extent of rebidding during an APP, which may include changes to the Rules, may be necessary to make this compensation option viable.

Notably, as discussed above, the NGF proposes in its submission that clause 3.14.6 of the Rules should be amended to allow the expert panel to consider rebids following the application of the APC to alleviate concerns regarding a "pay as bid" compensation regime. However, the NGF did not indicate how consideration of these rebids should or would influence the recommendations of the expert panel.[46]

A.4.1.4 The Commission's assessment of offer based compensation

The Commission considers that a compensation methodology which is based on the offers and bids of claimants, while simple to apply, has the potential to significantly increase the risks associated with an APP; both at the level of individual Market Participants and across the NEM as a whole.

In particular, the Commission considers offer based compensation has the potential to place retailers in a position of substantial risk, as such a regime is likely to yield compensation payments which are both large in size and highly volatile. Such a regime may also increase the risk of a retailer of last resort event, particularly if retailers are not able to pass through the costs of the compensation payment to their customers. This may result in systemic risk in the broader market, due to the secondary impact on counterparties who have entered into contracts with the insolvent retailer. However, as discussed above, the ability of retailers to pass through costs will depend on the type of contract they have with their customers and the regulatory framework of the jurisdiction(s) that they are operating in.

The Commission also agrees with the analysis by Concept Economics that a compensation regime based on bids and offers may effectively negate the purpose of

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42 Concept Economics, 2008. Risk Assessment of Alternative Compensation Options, p.29.

43 Ibid.

44 Concept Economics, 2008. Risk Assessment of Alternative Compensation Options, p.29.

45 Concept Economics, 2008. Risk Assessment of Alternative Compensation Options, p.13.

46 The Commission also notes that under clause 3.8.22A of the Rules, Participants are already required to make dispatch offers, bids or rebids in "good faith", and that under section 58(b)(i) of the NEL, the AER may seek penalties of up to $1,000,000 for breaches of this provision.

the CPT and APP arrangements to mitigate risk following an extended period of high prices. The Commission considers that this may occur as there is the potential that compensation payments to generators under this regime could be broadly equivalent to the uncapped spot price they would have received had the CPT not been triggered.

The Commission is also not convinced that compensation based on the bids and offers of claimants is necessary to ensure the supply reliability of the market during an APP. This is particularly since generators are able to earn a significant component of their fixed costs in the lead up to a CPT breach. The Commission also notes that the NGF indicates that it considers that the objective of the compensation provisions is not to provide generators with compensation equivalent to their offer prices. [47] Therefore it appears that both retailers and generators do not support a compensation regime which is based on the bids and offers of claimants.

As a result, for the reasons outlined above, the Commission has determined not to adopt a regime which is based on the bids and offers of claimants for compensation following administered pricing.

A.4.2 Compensation based on direct costs and opportunity costs

Compensation based on the direct costs and opportunity costs of claimants would take into account the short run marginal costs of claimants. This includes the opportunity cost associated with operating during an APP, compared to operating at an alternative date when the spot price may be higher. These types of opportunity costs are particularly relevant for fuel limited plants such as hydro and gas plants. Opportunity costs associated with additional operational and maintenance costs from operating during an APP as a result of being constrained on, would also be taken into account under this regime.

A.4.2.1 Views of first round submissions on offer based compensation

EA's Rule change proposal does not discuss the impact of compensation based on direct generating costs and opportunity costs.

Submissions from TRUenergy–AGL, ERAA, NGF and Macquarie Generation suggest that that the opportunity costs of generation should be included in the list of the "direct generating costs" to be considered by the expert panel. To do otherwise would not take into account the difficulty of calculating the fuel costs of hydro and gas generators.

In relation to the potential opportunity costs of gas generators, Macquarie Generation suggests that "increased production may result in the accelerated use of contracted gas supplies. This could result in lower gas availability during later dispatch periods when prices are no longer capped."[48] Macquarie Generation also suggests that this could result in higher prices for gas supply and transportation

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47 NGF, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 1.

48 Macquarie Generation, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 1.

when contracts are renegotiated. The NGF also indicates that the "relatively shallow and dynamically priced gas market"[49] would make it difficult for gas operators to quantify their fuel costs when applying for compensation.

Macquarie Generation and the NGF also suggest that even coal plants may have opportunity costs associated with generating during APPs, as a result of increased maintenance costs from operating at a high capacity.

A.4.2.2 Concept Economics' assessment of compensation based on direct costs and opportunity costs

Concept Economics indicates that compensation based on direct generating costs and opportunity costs, like compensation based on offer prices, can be highly volatile and uncertain. As a result, Concept Economics suggests that this type of compensation can create financial risks for retailers and revenue uncertainty for generators. Concept Economics also suggests that it is relatively difficult to implement and lacks transparency.

To demonstrate the uncertain nature of calculating opportunity costs, Concept Economics modelled the opportunity cost of water for three aggregate storage points, including Snowy Hydro and Hydro Tasmania. This modelling is based on data from June 2007 when the CPT was almost breached in NSW.

On average across all samples and storage points, Concept Economics indicates that the opportunity cost for a hydro MWh was $112 over June 2007, which is reflective of the high demand and low hydro storage over this period.[50] However, for 'low hydrology' scenarios, hydro opportunity costs averaged over $500/MWh, which reflects the increased value of water under a scenario of water scarcity.[51]

Concept Economics also notes that the opportunity cost of water can vary significantly with the timeframe that is used, inflows, regional demand, outages and interconnection availability, amongst other factors. Consequently, Concept Economics indicates that the opportunity costs of hydro generation can range from zero to VoLL, depending on the circumstances of the high price event.[52]

In regards to gas fired generation plants, Concept Economics indicates that gas supply interruptions may also yield an opportunity cost close to VoLL, particularly in regions which rely heavily on gas for periods of peak demand. However, the size of compensation payments would largely depend on the size and duration of the gas supply interruption.[53] Concept Economics also notes that the probability of gas infrastructure failure is fairly low in comparison to other events which may affect the NEM.

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[49] NGF, 2008, First round submission- Compensation under administered pricing, p. 1.

[50] Concept Economics, 2008. 'Risk Assessment of Alternative Compensation Options', p.27.

[51] Concept Economics, 2008. 'Risk Assessment of Alternative Compensation Options', p.28.

[52] Concept Economics, 2008. 'Risk Assessment of Alternative Compensation Options', p.29.

[53] Concept Economics, 2008. 'Risk Assessment of Alternative Compensation Options', p.37.

Overall Concept Economics indicates that compensation based on opportunity costs has a "theoretically sound base but appropriate data and modelling processes need to be developed and tested to render it an economically efficient and transparent means of compensation".[54]

A.4.2.3 The Commission's assessment of compensation based on direct costs and opportunity costs

The Commission considers that whilst compensation based on short run marginal costs (including opportunity costs) is not the simplest approach or necessarily the least cost approach, it appears to be the most likely option to provide the best balance between:

- Maintaining the incentive to supply during an APP; and
- Minimising the financial risks from a compensation payment following an APP.

The Commission acknowledges that compensation which takes into account the opportunity costs of claimants can create significant uncertainty for Participants. This is because the resulting calculation is highly dependent on the circumstances which have contributed to the application of the APP. The Commission also acknowledges that compensation based on opportunity costs can lead to high levels of compensation. However, the Commission considers that providing Participants with compensation which reflects the value of their service during an APP is necessary to ensure that the supply reliability of the market is maintained, particularly at a time of market instability.

Therefore, the Commission has determined to revise the compensation provisions in clause 3.14.6 of the Rules. Under the Commission's draft Rule, the expert panel will be required to take into account the direct costs and opportunity costs of the claimant when assessing claims for compensation.

Due to the series of extreme events which must occur for the CPT to be breached, the Commission considers that it is appropriate for the Commission to maintain a level of discretion to enable them to consider all the relevant circumstances when assessing compensation claims. Therefore the Commission will also be able to use its discretion when making an assessment.

The Commission has decided that the expert panel should calculate compensation based on direct costs and opportunity costs.

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[54] Concept Economics, 2008. 'Risk Assessment of Alternative Compensation Options', 9 July, p. 39.

A.5 Practicalities of implementing compensation based on direct costs and opportunity costs

A.5.1 Compensation guidelines

The Commission recognises that whilst compensation based on direct costs and opportunity costs maintains the incentive for participants to supply services during an administered price period, estimating opportunity costs is difficult and lacks transparency.

Concept Economics notes this feature in their report "Estimating opportunity cost for energy limited plants" .[55] In this report Concept Economics reveals that the fundamental issue associated with calculating opportunity cost is that the estimates can be both very high and volatile depending on the scope of the calculation. For this reason when other jurisdictions have applied compensation based on opportunity costs they have focused on developing guidelines that relate to objectives of practicality and transparency as opposed to what is right from a conceptual sense.

Therefore the Commission is proposing that the Rules should require that compensation guidelines be developed to overcome the complexities associated with the opportunity cost calculation. In particular the development of the guidelines is intended to:

- Enhance the transparency and predictability of the compensation calculation for both direct costs and opportunity costs;
- Avoid the difficulty of establishing guidelines whilst concurrently evaluating compensation applications; and
- Adhere to the current principles of regulatory design, whereby explanations of technical methodological details are contained in guidelines as opposed to the Rules, thereby providing the Commission with sufficient flexibility and scope to make subsequent changes.

To achieve the above objectives, the Commission considers that the guidelines should, at a minimum, set out:

- That the objective for compensation is to maintain the incentive for supplying electricity and other services during an administered price period and to maintain the incentive for investment in peaking generation assets;
- Include a statement that compensation is based on direct costs and opportunity costs;
- Set out the methodology to be used to calculate compensation, including defining direct generation costs, and the approach to estimating opportunity costs, consistent with any requirements set out in the rules; and

55 Concept Economics, Estimating opportunity cost for energy limited plants, 2008.

- Provide more detailed process and information gathering requirements, consistent with any requirements set out in the rules.

A.5.2 Proposed process for the development of guidelines

There are significant complexities associated with calculating compensation following administered pricing and in an effort to promote greater transparency and market certainty. The Commission is therefore proposing that the guidelines should be developed through a public consultation process.

The Commission acknowledges that there are a number of ways in which the public consultation process could operate. However to ensure consistency with other policy settings, the Commission proposes developing the guidelines in accordance with the transmission consultation procedures set out in Clause 6A.20(b) and (c). Under these procedures the Commission will be required to:

- Publish the proposed guidelines;

- Publish an explanatory statement which sets out the purpose and the reasons for the proposed guidelines; and

- Invite written submissions on the proposed guidelines for a period of no less than 30 business days.

Given the potential practical challenges associated with applying the guidelines, the Commission is of the opinion that there is merit in convening the expert panel to assist and provide advice in regards to the development of the draft guidelines.

The Commission has decided that in order to provide greater transparency and consistency to the compensation calculation, the Rules should require that compensation guidelines be developed. These guidelines are to be developed, in accordance with the Transmission Consultation Procedures, by 30 June 2009.

A.6 The process for determining compensation

A.6.1 Existing process

Clause 3.14.6 of the Rules requires market participants to lodge with the Commission and NEMMCO a notification of an intent to make a claim for compensation within three business days of the end of an APP. Following receipt of a claim, the Commission is required to set up a three member expert panel.

The purpose of the expert panel is to provide recommendations to the Commission on the matters before it and it is required to conduct itself on the same basis as the dispute resolution panel (clause 3.14.6(e)). This requirement is not prescriptive and provides the expert panel with considerable flexibility since it was designed to resolve disputes and not assess compensation claims. For example the expert panel can choose to conduct a consultation process (clause 8.2.6C), however this is not a mandatory requirement. The Rules do however require that the expert panel must make its recommendations to the Commission within 30 or 70 business days depending on whether there are two or more parties to the claim.

Following the receipt of advice from the expert panel the Commission is required to determine if compensation is warranted and if so the appropriate amount. In making its decision the Commission is not bound by any timeline nor is it required to publish its decision or the expert panel's recommendation.

A.6.2 EA's proposal

EA proposes a number of amendments to the Rules to clarify and improve the transparency of the process used to make compensation determinations.

These amendments to the Rules include the following requirements:

1. The expert panel must firstly consider whether it is appropriate for compensation to be paid, and if so what level of compensation should then be paid.;

2. The Commission must publish the expert panel's report;

3. The Commission must publish a draft report setting out its draft determination prior to making its final determination;

4. The Commission must invite written submissions and comments from interested parties on the expert panel's report and the Commission's draft report, for a period of not less than 20 business days;

5. In making its final determination the Commission must take into account, but is not bound by the expert panel's report and any submissions received; and

6. The Commission must publish its final determination.

A.6.3 Views of first round submissions

There were limited submission responses in relation to EA's proposed changes to the process used for compensation determinations.

ERAA supports EA's proposed changes and suggests that they would increase transparency in the compensation provisions, clarify the roles of the Commission and the expert panel, and reduce market uncertainty in relation to how compensation is determined.[56]

TRUenergy-AGL proposes an amendment to the process used for compensation determinations. They propose that the time to submit compensation claims should be increased from two business days to at least five business days given the

[56] ERAA, 2008, First round submission- Compensation Arrangements Under Administered Pricing Rule change proposal, p. 1.

"potential complexity of determining direct costs and that the APC is likely to be applied for a continuous period of several days".[57]

A.6.4 The Commission's assessment

The Commission agrees with EA's assertion that the current process for determining compensation lacks guidance as to the methodology that is used to calculate compensation and the process by which compensation will be determined. In particular the process through which the expert panel and Commission must assess and calculate compensation requires greater prescription.

The Commission notes that the existing arrangements may create uncertainty in relation to how compensation will be determined, thereby exacerbating the risk to market participants. The Commission therefore proposes to introduce a new process to assess claims. The proposed process draws upon EA's proposal, although the Commission has chosen to make a more preferable Rule by including two additional components, as accorded under Section 91A of the NEL.

The Commission's proposed process for assessing compensation, which is discussed below, is as follows:

1. **Market participants must lodge with the Commission and NEMMCO a notification of an intent to make a claim for compensation within five business days of the end of an administered price cap period;**

The Commission supports the proposal by TRUenergy-AGL to increase the time provided to Participants to prepare claims for compensation from two to five business days. The Commission agrees that the preparation of claims is a complex process which may take longer than two business days. The Commission also notes that an extension of time to submit claims will also serve to further align the compensation process following administered pricing with other compensation processes in the Rules. The Commission considers that this will provide greater consistency in the Rules, which is good regulatory practice. For instance, in relation to the provisions for compensation following reliability directions and the dispatch of reserve contracts by NEMMCO, clause 3.12.11(c) of the Rules indicates that after a directed participant is notified by NEMMCO of their eligibility to claim a given amount of compensation they have up to seven business days to prepare a written submission to NEMMCO.

2. **The Commission must then request under Rule 3.14.6 that the advisor establish an expert panel to make recommendations on the validity of the claim and the appropriate level of compensation;**
3. **The expert panel is not required to conduct itself on the same basis as the dispute resolution panel and instead must base its draft recommendation on the compensation guidelines;**

[57] TRUenergy-AGL, 2008, First round submission- Compensation Arrangements Under Administered Pricing Rule change proposal, p. 1.

To facilitate the public consultation process below and to enable greater prescription in regards to how the expert panel conducts itself, the Commission no longer deems it appropriate that the expert panel must conduct itself on the same basis as the dispute resolution panel. In particular it would not be feasible to conduct a public consultation process if the expert panel is required to make its recommendation to the Commission within 30 (or 70 business days).

Therefore the Commission proposes to delete clause 3.14.6(e) and replace it with detailed guidance on the process to be followed by the expert panel in making its recommendation. This would include that:

- The expert panel must make its recommendation in line with the compensation guidelines; and
- The expert panel is required to publish both a draft and final report detailing its compensation calculation.

4. The Commission is required to publish its proposed determination of compensation and the expert report and invite submissions for a period of up to 20 days;

The Commission considers that EA's proposal for publicly releasing the expert panel's report and the Commissions draft determination and inviting submissions for a period of 20 days is a significant improvement on the existing arrangements. A public consultation process is in accordance with good regulatory practice. It is also consistent with the Commission's accepted mode of operation in relation to its other functions and responsibilities (e.g. market reviews and Rule changes). The Commission also considers that it will improve the transparency of the compensation process and ensure that the market is kept informed of how claims are being processed. This is particularly because the processing of these claims may result in Participants being liable for (or owed) potentially large compensation payments.

5. The expert panel is then required to prepare a final report which is released simultaneously with the Commission's final determination; and

Consistent with EA's proposal, the Commission recognises the benefit in publishing its final determination to promote greater transparency in the compensation process. The Commission also recognises that submissions on the draft determination and expert report may be of a technical nature, thereby necessitating further input from the expert panel. The Commission therefore considers it appropriate for the expert panel to prepare a final report that addresses any technical issues raised in the submissions and this report should be published with the Commission's final determination.

6. The length of the entire process should be no more than 150 business days, which is in line with the Intervention Settlement Timetable (Rule 3.12.1(a)(2)).

The Commission notes that EA did not specify any timeframes, other than the 20 day consultation period, that would apply to its revised compensation process. In particular, EA has not specified:

- The total timeframe over which the compensation process should operate; or

- The timeframes for each component, such as how long the Commission would have to publish its draft report following the completion of the expert panel's report.

The Commission has reviewed existing compensation provisions in the Rules to examine how these provisions establish timeframes. An interesting observation that emerges is that while most compensation processes establish the requisite steps that must be undertaken, they do not specify the time for each step. For the most part, compensation processes defined in the Rules only specify the maximum length of the overall process.

In the interests of promoting greater regulatory certainty in the compensation process, the Commission is proposing to define the timeframe for each requisite step. Additionally, to promote consistency with other policy settings the Commission proposes that the overall timeframe should be no more than 150 business days. This is the same maximum timeframe used when compensating participants following market intervention by NEMMCO.

Figure 1 below contains a summary of the Commission's proposed process for the determination of compensation following administered pricing. The Commission is seeking stakeholder feedback on its proposed process and whether stakeholders believe that it is likely to improve the clarity and transparency of the compensation process.

The Commission has decided that the compensation process in the Rules should be amended to enable a public consultation process on the draft expert report and the draft determination.

The Commission has also decided to increase the number of days in which participants can lodge a claim to five days.

A.7 Funding of the compensation determination process

In undertaking this draft determination and in particular examining the complexities associated with calculating compensation, the Commission has become aware that the process for evaluating compensation claims is likely to be time consuming and costly.

The report prepared by Concept Economics on estimating the opportunity cost for energy limited plants reveals the magnitude of the opportunity cost calculation. For instance any opportunity cost calculation will be highly data intensive and it is likely to be more significant that an ANTS or SOO new entry study be conducted by NEMMCO. [58]

Therefore to ensure that the Commission has adequate funding to effectively undertake the process, it is proposing that any costs incurred may be recovered from the applicant.

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[58] Concept Economics, Estimating opportunity cost for energy limited plants, 2008, p. 19.

The Commission has decided that the cost of assessing compensation claims should be capable of being recovered from the applicant(s).

Figure 1- The Commission’s proposed process for the determination of compensation following administered pricing

Claims for compensation are submitted to the AEMC and NEMMCO within five business days of the trading interval in which offer prices were adjusted or notification by NEMMCO that the APP has ended.

AEMC establishes a three member expert panel

Expert panel considers whether compensation is warranted and, if so, the appropriate amount in line with the compensation guidelines.

Expert panel provides its recommendations/ draft expert report to the AEMC within 30 business days of receiving the information required under the compensation guidelines.

AEMC must publish the expert panel’s report and its draft determination on whether compensation is appropriate and, if so, the level of compensation it will award within 20 business days of receiving the expert panel’s draft report.

Public consultation on the AEMC’s draft report and the expert panel’s report for no less than 20 business days following the date of publication.

Expert panel to consider submissions and prepare a final recommendation within 20 business days after the closing date of submissions.

AEMC to publish the expert panel’s final report and its final determination on whether compensation is appropriate and if so the level of compensation it will award within 15 business days of receiving the expert panel’s draft report.

Market Customers in the regions in which prices were adjusted are required to pay compensation in proportion to the energy purchased in the affected trading intervals.

Compensation is paid through the settlement process. NEMMCO must provide Participants with statements outlining the compensation amounts payable to/ by Participants within 15 business days of the AEMC’s final report, under clause 3.15.10 of the Rules.

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B Factors which may lead to a CPT breach

B.1 Background

This Appendix assesses a number of recent high price incidents when the CPT has been breached or has been close to being breached, in order to identify the conditions and circumstances which may have led to these high price incidents. Understanding the conditions will assist in identifying the likelihood of future CPT breaches and in managing the risks of a CPT breach. This understanding is useful in assessing EA's Rule change proposal, as the objective of EA's proposed changes is to mitigate the financial risks for Participants, particularly retailers, following a breach of the CPT and the application of administered pricing.

The CPT has only been breached once since NEM commencement, on 17 March 2008 in South Australia (SA). However, over the last 12 months there have been four occasions when the CPT has been close to breaching the $150,000 threshold:

1. 12 to 28 June 2007 in New South Wales (NSW), when the rolling seven day price reached $135,000;

2. 11 January 2008 in SA, when the rolling seven day price reached $138,000;

3. 19 February 2008 in SA, when the rolling seven day price reached approximately $143,000; and

4. 23 February 2008 in Queensland, when the rolling seven day price reached $144,000.

This Appendix will examine these five high price incidents and the contributing circumstances and conditions.

B.2 Summary and analysis of the contributing factors to the high price incidents

Analysis of the five high price events indicates that there appear to be four key factors which contribute towards a CPT breach:

1. High demand levels, arising from extreme high or low temperatures;

2. Binding interconnector constraints or the loss of an interconnector;

3. Bids close to VoLL by generators with transient market power in a region (especially large base load units); and

4. A lack of generation capacity availability.

The five events demonstrate that the occurrence of one of these factors alone is not enough to lead to a rolling seven day price close to the CPT. Rather a combination of two or more of these factors is required to drive the cumulative price towards the CPT.

Although it appears that a combination of these factors can lead to high price events, it can be difficult to predict and forecast the simultaneous occurrence of these factors. For example, predicting when an interconnector will reach its limit or be lost is difficult because it depends on the dispatch process and network operational activities by TNSPs and/or NEMMCO (e.g. switching, outages, use of Network Support and Control Services etc). This reinforces the notion that a combination of extreme and unpredictable events is required to occur, in order for the CPT to be breached or be close to being breached.

A binding interconnector limit or the loss of an interconnector appears to be a critical factor as it reduces the number of sources of generation available to meet demand in a region. This in turn changes the competitive dynamics across the NEM, and can enable some generators to exercise transient market power. Generator availability is also affected by:

1. The timing of planned maintenance, which can be a strategic decision by a generation company;[59]

2. Energy constraints, which can relate to:

   (a) fuel supply contracts (e.g. gas take-or-pay contracts);

   (b) hydrological limitations and/or inter-temporal optimisation; and

   (c) water restrictions relating to drought (e.g. limits on the use of water for cooling thermal generation plants); and

3. Strategic use of generation capacity in order to influence the level of the RRP in one or more regions. This can be done by bidding capacity unavailable or by making capacity available at a high price at a certain time of day, season, and/or location on the network.

Changes in the average level of the RRP and the volatility of the RRP also have flow on effects on the prices of financial hedge contracts. These changes in contract prices can affect:

- Sales revenue for generators;
- Electricity purchase costs for retailers; and consequentially; and
- The profitability and risks that these Participants may face.

In the long term, changes in contract prices also affect investment in new capacity and the broader reliability of the NEM.

59 Chattopadhyay, D. 2004, " A game theoretic model for strategic maintenance and dispatch decisions", IEEE Transactions on Power Systems, Vol 19, No. 4, November 2004.

Both NEMMCO[60] and the Reliability Panel[61] consider that it is likely that the reliability standard will be met in most NEM regions over the next eighteen months, after taking into account the supply-demand outlook and the likely impact of the drought. NEMMCO has forecast that the reliability standard may not be met under a low rainfall scenario in Victoria in summer 2010.[62] However, under an average rainfall scenario, NEMMCO forecasts that Victoria will meet the reliability standard over this period.[63] Therefore, both NEMMCO and the Panel consider that there will be sufficient capacity available to meet forecast levels of regional demand. This forecast tends to reduce the likelihood of a CPT breach over the short term, but it does not eliminate the risk of a breach.

As discussed in Chapter 1, it should also be noted that the Reliability Panel has recommended in the Final Report of its Comprehensive Reliability Review (CRR) that VoLL and the CPT be increased from $10,000/MWh and $150,000 to $12,000/MWh and $187,500 respectively.[64] The Reliability Panel has indicated in the Final Report of the CRR that it intends to consult on an exposure draft of Rule changes proposing to increase the level of VoLL and the CPT in April or May 2008.[65] Modelling undertaken by CRA International in Appendix E of the Final Report of the CRR demonstrated that an increase in the level of the CPT from $150,000 to $200,000, would significantly reduce the incidence of CPT breaches each year.[66] Therefore, these changes to the level of VoLL and the CPT should assist to reduce the likelihood of CPT breaches, if adopted by the Commission. The Reliability Panel proposed in the Final Report of the CRR that it would seek to give effect to these changes from 1 July 2010.[67]

B.3 Analysis of high price incidents

B.3.1 17 March 2008– SA

On 17 March 2008, the CPT was breached in SA and an APP was put in place from 5:30 pm on 17 March 2008 till 4:00 am on 19 March 2008.[68] During the APP, prices for energy and frequency control ancillary services (FCAS) were capped at the APC ($100/MWh from 7:00 am to 11:00 pm on business days and at $50/MWh at all other times). In addition, SA imports of energy from other regions during the APP led to

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60 NEMMCO, 2008, Drought Scenarios Investigation: June 2008 Update, 2 July. Available at: http://www.nemmco.com.au/about/900-0005.pdf; NEMMCO, 2007, Statement of Opportunities 2007. Available at: http://www.nemmco.com.au/nemgeneral/040-0047.pdf

61 AEMC Reliability Panel, 2007, Final Report- Comprehensive Reliability Review, 21 December.

62 NEMMCO, 2008, Drought Scenarios Investigation: June 2008 Update, 2 July, p. 5.

63 Ibid.

64 Ibid.

65 Ibid.

66 CRA International, 2007, 'Appendix E: Modeling Methodology, Input Assumptions and Results: Second Stage Modeling', *CRR,* December, p. 33.

67 AEMC Reliability Panel, 2007, Final Report- Comprehensive Reliability Review, 21 December.

68 NEMMCO, 2008, Pricing Event Reports- March 2008: 17 March 2008. Available at: http://www.nemmco.com.au/marketandsystemevents/pricing_mar.htm

the prices in Victoria, Snowy, New South Wales, and Queensland regions to be scaled back at various times.[69]

No claims for compensation in relation to this event were received by the Commission or NEMMCO.

The AER has completed an investigation into this high price event and has identified the following factors as contributing to this event:

- Strong demand for electricity;
- Generator offers and rebidding; and
- Network constraints.

B.3.1.1 Strong demand for electricity

NEMMCO indicates that prior to 17 March there had been 14 days of high temperatures above 35 degrees, which led to high demand for electricity.[70] In its Pricing Event Report on this incident, NEMMCO notes that on 17 March Adelaide and Melbourne recorded temperatures of 40 degrees and 38 degrees respectively.[71] The AER indicates that these conditions led to unprecedented demand levels in SA, with a new daily demand record of 3077 MW set in SA on 17 March.[72]

B.3.1.2 Generator offers and rebidding

The AER suggests that bidding behaviour by AGL significantly contributed to the high price events in SA and the breach of the CPT.

In its report, the AER notes that AGL's Torrens Island power station is the marginal scheduled generator in SA, in that when demand in SA exceeds 2500 MW, Torrens Island power station must be dispatched. More information on the Torrens Island power station can be found in the First Final Report by the AEMC on the Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia.[73]

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69 Ibid.

70 NEMMCO, 2008, Administered Price Event March 2008, Presentation to NEM Forum #84, 24 April. Available at: http://www.nemmco.com.au/nemgeneral/057-0376.pdf

71 NEMMCO, 2008, Pricing Event Reports- March 2008: 17 March 2008.

72 Ibid.

73 AEMC 2008, Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, First Final Report, 19 September 2008, Sydney.

B.3.1.3 Network constraints

Limited network availability on interconnectors between SA and Victoria also appears to have contributed to the high price events in SA over March 2008. The AER notes that a maximum of only 360 MW could be imported into SA along the Heywood interconnector in March 2008, following reductions in the import limit by ElectraNet SA. In addition, the flow on the Murraylink interconnector was limited to less than 100 MW over March 2008 due to a voltage stability limit.[74] Therefore, the combined maximum import limit into SA along the Heywood and Murraylink interconnectors was less than 450 MW during March 2008.

The import limit into SA was also further reduced by around 260 MW along the Heywood interconnector on 12 March, following a lightening strike which led to the simultaneous trip of the Tailem Bend to Tungkillo and the Tailem Bend to Cherry Gardens 275 kV lines. NEMMCO notes that this contingency, combined with strong demand and bids close to VoLL by AGL's Torrens Island power station for a significant amount of its capacity, led to spot prices near VoLL for two hours on 12 March 2008 in SA.[75] The AER indicates that this incident let to the cumulative price remaining above $120,000.

B.3.2 23 February 2008– Queensland

On 23 February 2008 in Queensland, the rolling seven day price reached $144,000. High prices were recorded in Queensland on 22 and 23 February, with prices peaking at $9591/MWh and $9153/MWh respectively.[76] NEMMCO issued a market notice at 3:45 pm on 23 February to alert the market that the CPT was forecast to be breached at 4:30 pm based on pre-dispatch.[77] Following this market notice by NEMMCO, approximately 175 MW of Queensland generation capacity was shifted to the lower priced bands between 3:45 pm and 3:50 pm.[78] Demand in Queensland also fell and as a result the CPT was not breached by the end of the day. [79]

The AER has identified the following factors as contributing to this incident:

- Strong demand for electricity;
- Network constraints; and
- Generator bidding and rebidding.

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74 NEMMCO, 2008, 'Pricing Event Report- March 2008: 12 March 2008'. Available at: http://www.nemmco.com.au/opreports/pricing_mar.html

75 NEMMCO, 2008, 'Pricing Event Report- March 2008: 12 March 2008'

76 AER, 2008, Spot prices greater than $5000/MWh: Queensland 22 & 23 February 2008. Available at: http://www.aer.gov.au/content/item.phtml?itemId=719164&nodeId=15d2b9f3e73f887855f5d47fe3ee53f8&fn=Prices%20above%20%245000/MWh%20report%20%20-%2022%20and%2023%20February%202008.pdf

77 NEMMCO, 2008, Pricing event report- Saturday 23 February 2008. Available at: http://www.nemmco.com.au/marketandsystemevents/pricing_feb.htm

78 Ibid.

79 Ibid.

B.3.2.1 Strong demand for electricity

On 22 and 23 February Brisbane recorded high temperatures of 33 degrees and 39 degrees respectively.[80] This contributed to strong demand for electricity. On 22 February demand reached 8100 MW, the highest demand recorded for the summer of 2008 in Queensland and within 500 MW of the highest demand recorded in Queensland ever.[81] On 23 February, demand reached 8000 MW, the highest weekend demand ever.[82] Actual demand on 23 February was also higher than forecast, with demand at times up to 486 MW higher than forecast four hours ahead.[83]

B.3.2.2 Network constraints

On 22 and 23 February flows into Queensland from NSW were restricted on the QNI and Terranora interconnectors to around 200 MW.[84] Flows were restricted to ensure there would be an adequate supply of imports to meet demand, if Queensland's largest generator 750 MW Kogan Creek was lost. Kogan Creek was commissioned in late 2007 and is about 200 MW larger then the next largest generator in Queensland.[85]

An unplanned outage of network equipment reduced the capacity of QNI by a further 40 MW, while a planned outage in northern NSW on 23 February forced flows of up to 50 MW from Queensland to NSW across the Terranora interconnector.[86]

B.3.2.3 Generator bidding and rebidding

On 22 and 23 February more than 20% of capacity in Queensland was offered at prices above $5000/MWh as a result of initial offers and a number of rebids by Millmerran Energy Trader, CS Energy and Stanwell Corporation which shifted capacity from lower price bands to prices about $5000/MWh. In addition, over this two day period, 12% of Queensland's capacity was not available to the market.

A summary of generator's bidding behaviour and availability during periods of high demand on 22 and 23 February in Queensland can be found below in **Tables 1 and 2**. The AER is currently investigating the rebids that occurred during this period to assess compliance with the good faith provisions in the Rules.

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80 AER, 2008, Spot prices greater than $5000/MWh: Queensland 22 & 23 February 2008.

81 Ibid.

82 Ibid.

83 Ibid.

84 NEMMCO, 2008, Pricing event report- Saturday 23 February 2008.

85 AER, 2008, Spot prices greater than $5000/MWh: Queensland 22 & 23 February 2008.

86 Ibid.

Table 1: 22 February 1:00 pm to 4:00 pm Generator Bidding Behaviour and Availability, Queensland region

Participant	Registered rating	Capacity priced above $5000/MWh	Capacity not presented	Combined total as % of registered rating**
AGL Hydro Partnership	514	0	6	1%
Callide Power Trader	840	0	390	46%
CS Energy	2639	387	489	33%
Ergon Energy Queensland	55	0	4	7%
Millmerran Energy Trader	852	166	-8*	19%
Braemar Power Project	504	0	45	9%
Origin Energy	368	0	25	7%
Stanwell Corporation	3264	426	420	26%
Tarong Energy	2343	1180	-56*	48%
TOTAL	**11379**	**2159**	**1314**	**31%**

* A negative value indicates that more capacity was presented across the portfolio than the summer rating on the plant.

** This column shows capacity priced above $5000/MWh and capacity not presented as a proportion of each generator's registered capacity.

Table 2: 23 February 12:30 pm to 3:30 pm Generator Bidding Behaviour and Availability, Queensland region

Participant	Registered rating	Capacity priced above $5000/MWh	Capacity not presented	Combined total as % of registered rating**
AGL Hydro Partnership	514	1	3	1%
Callide Power Trader	840	0	400	48%
CS Energy	2639	393	515	34%
Ergon Energy Queensland	55	0	55	100%
Millmerran Energy Trader	852	0	72	8%
Braemar Power Project	504	0	50	10%
Origin Energy	368	0	24	6%
Stanwell Corporation	3264	780	296	33%
Tarong Energy	2343	1297	-100*	51%
TOTAL	**11379**	**2471**	**1314**	**33%**

Source: AER, 2008, Spot prices greater than $5000/MWh: Queensland 22 & 23 February 2008, p. 5.

B.3.3 11 January 2008 & 19 February 2008– SA

On 11 January 2008 in SA, the rolling seven day price reached $138,000.[87] High prices on 10 January 2008, appear to have contributed to this high price event. On 10 January 2008, between 2:05 pm and 5:30 pm, the regional reference price for SA was $9,999.72/MWh,[88] while prices for the Snowy and Victoria regions reached $8,176 and $7600 respectively at 3:55 pm.[89]

On 19 February 2008 in SA, the rolling seven day price reached $143,000.[90] Like the high price incident in January 2008, the high cumulative price on 19 February was largely the result of high prices on the previous day. On 18 February 2008 between 12:30 pm and 6:30 pm alone, high prices in SA pushed the cumulative price from $15,000 to $134, 000.[91]

The AER and NEMMCO have identified the following factors as contributing to these incidents:

- Strong demand for electricity;
- Generator bidding and rebidding; and
- Binding network constraints.

B.3.3.1 Strong demand for electricity

On 10 January 2008, temperatures reached 41 degrees in Adelaide and 40 degrees in Melbourne, which led to strong demand for electricity.[92] SA recorded Record demand levels in the late afternoon of 10 January 2008 of 2916 MW[93]. Demand was above 2500 MW between 11:30 am and 8:30 pm on 10 January and for most of this period prices were over $5000/MWh.[94]

On 18 February and 19 February 2008, temperatures in Adelaide reached 37 degrees and 38 degrees respectively, with demand at near the record levels set on 10 January.[95] On 18 February, demand reached 2897 MW and was above 2500 MW

87 AER, 2008, Spot prices greater than $5000/MWh: South Australia 4 & 10 January 2008, 18 & 19 February 2008. Available at: http://www.aer.gov.au/content/item.phtml?itemId=717893&nodeId=873aaa41a6ecef22c908d21881813db4&fn=Prices%20above%20%245000/MWh%20report%20-%204%20and%2010%20January%20and%2018%E2%80%9319%20February%202008.pdf

88 NEMMCO, 2008, Pricing Event Reports- Thursday 10 January 2008. Available at: http://www.nemmco.com.au/marketandsystemevents/pricing_jan.htm

89 Ibid.

90 AER, 2008, Spot prices greater than $5000/MWh: South Australia 4 & 10 January 2008, 18 & 19 February 2008

91 Ibid.

92 Ibid.

93 Ibid.

94 Ibid.

95 Ibid.

between 11:30 am and 8:00 pm.[96] On 19 February, demand reached 2838 MW and was above 2500 MW between 12:30 pm and 6:30 pm.[97] In the previous seven days demand did not exceed 2500 MW. [98]

B.3.3.2 Generator bidding and rebidding

On 10 January 2008, a significant amount of capacity was offered by Torrens Island Power Station at close to VoLL, with 890 MW of its 1160 MW capacity offered to the market at more than $9,900/MWh.[99] The capacity offered by Torrens Island comprised almost one third of demand on 10 January. As a result, these bids from Torrens Island effectively set the high prices which were recorded on 10 January.[100]

On 18 February between 12:30 pm and 6:30 pm, 80% of Torrens Island's capacity was offered at close to VoLL, which set the price at almost $10,000/MWh. [101] For most of the day on 19 February, Torren's Island online capacity of 1150 MW was priced below $500/MWh.[102] However a number of rebids by Torrens Island, which occurred during the afternoon of 19 February served to increase prices in SA. At 1:45 pm Torrens Island rebid 600 MW from prices below $150/MWh to above $8500/MWh for trading intervals between 2:00 pm and 3:00 pm, while at 5:30 pm 820 MW were rebid from prices less than $150/MWh to above $8500/MWh for the 6:00 pm trading interval.[103] The reasons given to NEMMCO for both these rebids was 'Portfolio Optimisation: Price/Volume Trade Off".[104]

On 19 February in the 6:00 pm trading interval, rebids of capacity from Angaston generators (49 MW) and International Power's Synergen portfolio (87 MW) to prices above $5000/ MWh were also recorded.[105] The AER is currently investigating the rebids that occurred during this period to assess compliance with the good faith provisions in the Rules.

B.3.3.3 Binding network constraints

During the high price events in January and February 2008 in South Australia, the limits for imports between Victoria and SA across the Murraylink and Heywood interconnectors were significantly lower than historical levels and the 700 MW sold

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96 Ibid.

97 Ibid.

98 Ibid.

99 NEMMCO, 2008, Pricing Event Reports- Thursday 10 January 2008.

100 AER, 2008, Spot prices greater than $5000/MWh: South Australia 4 & 10 January 2008, 18 & 19 February 2008.

101 Ibid.

102 Ibid.

103 Ibid.

104 Ibid.

105 Ibid.

through the settlement residue auction process.[106] The average combined Heywood and Murrarylink limit during the high price events in January and February 2008 was 395 MW. This is partly the result of a reduction in the import limits into SA by around 140 MW or 28% by Electranet, the South Australian transmission network service provider (TNSP) and SP Ausnet, the Victorian TNSP.[107] In late 2007, Electranet revised down the import limits on the Heywood interconnector, which reduced maximum flows from around 460 MW to 360 MW.[108] In 2003, SP Ausnet reduced import limits into SA from around 500 MW to 460 MW.[109]

The import limit for Murraylink was also around 100 MW lower than forecast prior to dispatch.[110]

These reductions in the import limit into SA served to reduce the supply of lower priced electricity from Victoria.

B.3.4 12-28 June 2007– NSW

During the period between 12-28 June 2007, the rolling seven day price reached $135,000 in NSW.[111] Prices in NSW, Queensland and the Snowy region exceeded $5000/MWh 42 times during this period.[112] The high prices during this period resulted in a significant increase in monthly average prices in NSW, Queensland, Victoria and SA. In June 2007 the average monthly price was $274/MWh in NSW, $216/MWh in Queensland, $157/MWh in Victoria, and $111/MWh in SA.[113] In comparison, prices in June 2006 ranged from $26/MWh to $42/MWh across the NEM. The high price period over June 2007 led to the first retailer of last resort (ROLR) event since NEM commencement, when a small second tier retailer voluntarily invoked suspension of its retail activities.

Both the AER and NEMMCO have completed reports outlining the conditions which led to this event. In their report, 'Prices above $5000 per megawatt hour in the National Electricity Market: June 12 to June 28 2007', the AER identified the following three factors as contributing to the June 2006 events:

- Strong electricity demand;
- Offline and constrained plant; and

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106 Ibid.

107 Ibid.

108 Ibid.

109 Ibid.

110 Ibid.

111 AEMC Reliability Panel, 2007, Final Report- Comprehensive Reliability Review, p. 84.

112 AER, 2007, *Prices above $5000 per megawatt hour in the National Electricity Market: June 12 to June 28 2007.* Available at: http://www.aer.gov.au/content/item.phtml?itemId=712933&nodeId=d531a542eb729da094b0b407c41dd2f6&fn=Prices%20above%20%245000/MWh%20report%20-%2012-28%20June%202007.pdf

113 Ibid.

- Generator rebidding.

In addition, the AER indicates that temporary transmission outages and limitations which constrained the flow of electricity to NSW from the Queensland and Snowy regions, contributed in part to the June 2007 events.[114]

B.3.4.1 Strong electricity demand

Over the 12-28 June period, record daily demand was set in NSW, Tasmania, and across the NEM as a whole. Record winter daily demand was recorded in SA, Queensland and Victoria.[115] Notably in NSW there were some significant discrepancies between actual and forecast demand over this period, with actual demand in NSW at times more than 7% higher than the forecast 12 hour demand.[116]

B.3.4.2 Offline and constrained plant

During June 2007 the drought in south eastern Australia constrained the hydro-generating capacity in Snowy, Tasmania and Victoria and also constrained the availability of water for cooling in some coal fired generators in NSW, Victoria and Queensland.

This lack of generator availability was exacerbated by an additional number of generator outages due to maintenance and plant problems. The AER indicates that in total up to 20% and 22% of NSW and Queensland plants were respectively unavailable during the high price events in June 2007. A number of plants in NSW and Queensland were also available but were operating at reduced capacity. Capacity reductions were greater in NSW than in Queensland, and were caused partly by "the effects of rain and flooding in the vicinity of the Hunter Valley coal mines and the boiler stability problems caused by wet coal".[117]

B.3.4.3 Generator rebidding

The AER suggests that the effect of the tight supply-demand balance on spot prices during June 2007 was further exacerbated by generator behaviour, particularly by Macquarie Generation. The AER indicates that during the 12-28 June period, Macquarie Generation repriced up to 21% (800 MW) of its capacity from below $500/MWh to above $5000/MWh during the peak evening demand period between 5 pm and 7:30 pm.[118] Due to record demand in NSW over the June 2007 period, some of these high priced offers were dispatched. As Macquarie Generation has the

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114 Ibid.

115 Ibid.

116 AER, 2007, *Prices above $5000 per megawatt hour in the National Electricity Market: June 12 to June 28 2007,* p. 19.

117 AER, 2007, *Prices above $5000 per megawatt hour in the National Electricity Market: June 12 to June 28 2007,* p. 7.

118 AER, 2007, *Prices above $5000 per megawatt hour in the National Electricity Market: June 12 to June 28 2007,* p. 2.

largest generating portfolio in the NEM, with over 10% of total NEM capacity, it was able to effectively set the spot price for almost half the times that the price was over $5000/MWh over the 12-28 June 2007 period.[119]

119 AER, 2007, *Prices above $5000 per megawatt hour in the National Electricity Market: June 12 to June 28 2007,* p. 16.

C Issues raised in first round submissions

C.1 Background

This Appendix contains a summary of the key issues raised in first round submissions received by the Commission on EA's Rule change proposal.

On 20 December 2007, the Commission issued a notice under Section 95 of the NEL, indicating its decision to initiate the Rule making process and first round consultation on EA's Rule change proposal. First round consultation closed on 22 February 2008.

As discussed in Chapter 2, the Commission received five first round consultation submissions which were from the following organisations:

- AGL Hydro Partnership and TRUenergy;
- The Energy Retailers Association of Australia (ERAA);
- Macquarie Generation;
- National Generators Forum (NGF); and
- NEMMCO

Copies of these submissions are available on the Commission's website.

C.2 Key issues raised in first round submissions

The main issues that were raised in submissions include:

- The eligibility for compensation;
- The financial risks for Market Participants under the current Rules; and
- How "direct generating costs" should be calculated.

These issues are discussed in further detail below.

C.2.1 Eligibility for compensation

Under clause 3.14.6 of the Rules, Scheduled Generators, Scheduled Network Service Providers, Market Participants, and ancillary service generating units and loads are eligible to claim compensation following administered pricing. However, EA is seeking to apply its proposed changes to restrict compensation to "direct generating costs" to Scheduled Generators only. As highlighted in Chapter 1, EA indicates that it is seeking to restrict its proposed changes to Scheduled Generators only, as the majority of compensation claims following an APP are likely to come from Scheduled Generators. Furthermore EA claims that the calculation of the direct costs of MNSPs and demand side bidders is more complex than the calculation of the direct costs of Scheduled Generators.

Submissions from NEMMCO, TRUenergy–AGL and ERAA indicate support for extending EA's Rule change proposal to the other categories of participants currently eligible to claim compensation under clause 3.14.6 of the Rules. NEMMCO and ERAA indicate this would ensure consistency in the Rules. TRUenergy–AGL indicates that EA's reasoning for excluding these other categories of Participants was flawed because:

- Market Network Service Providers (MNSPs) are able to claim compensation under a greater number of circumstances than Scheduled Generators; and
- The direct costs of MNSPs and ancillary service generating units and loads are relatively simple to determine as they are externally assessable from NEMMCO data.[120]

C.2.2 Financial risks for Market Participants under the current Rules

TRUenergy–AGL, ERAA and Macquarie Generation highlight the financial risks for retailers from the current compensation provisions. TRUenergy–AGL and ERAA both indicate that the current compensation provisions create uncertainty regarding how compensation would be determined by the expert panel and what the consequent financial impact on retailers may be following an APP. TRUenergy–AGL and ERAA both suggest that EA's Rule change proposal would reduce the risk of large and unhedgable compensation payments for retailers.

Macquarie Generation notes the difficulties that retailers may have in managing a compensation payment, as "customers are reluctant to agree to contracts that allow the pass through of unknown levels of compensation"[121] and there is no "active market for insurance products that could provide cover during these periods".[122] However, Macquarie Generation indicates that retailer risks from compensation payments would be better addressed by setting the APC at a level that covered the costs of marginal generating plant in most circumstances.

Macquarie Generation and the NGF also dispute EA's claim that the current compensation provisions are likely to create a potential "pay as bid" scenario, whereby generators increase their offers once the APC is applied and are compensated at a level similar to the uncapped spot price, rendering the risk management mechanisms of the APC and CPT ineffective. Macquarie Generation suggests that in practice generators face the risk that their competitors will offer lower priced output to the market to cover contract positions or earn spot revenue, and notes that generators who are not dispatched will not be eligible for compensation. The NGF suggests that to reduce concern regarding a "pay as bid"

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120 TRUenergy-AGL, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 2.

121 Macquarie Generation, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 2.

122 Ibid.

scenario, the current compensation provisions should be amended to allow the expert panel to consider changes to dispatch offers co-incident to the application of the APC.

TRUenergy–AGL also highlight the difficulty of forecasting the operation of the APC under the current Rules as a source of risk and uncertainty for Participants, as the application of the APC is affected by inter-regional flow direction under clause 3.14.2(e)(2) of the Rules. This issue is discussed in detail in **Appendix D**.

C.2.3 Calculation of "direct generating costs"

EA is seeking to limit compensation to Scheduled Generators to the following "direct generating costs" associated with dispatched generating units during the APP:

- Fuel costs;
- Incremental maintenance costs; and
- Incremental manning costs.

TRUenergy–AGL, ERAA, NGF and Macquarie Generation highlight the difficulty of quantifying the fuel costs of hydro generators. TRUenergy–AGL and ERAA both suggest that the opportunity costs of generation should be included in the list of "direct generating costs" to be considered by the expert panel, in order to take into account the difficulty of calculating the fuel costs of hydro generators.

The NGF and Macquarie Generation also suggest that the direct generating costs of coal and gas plants would not be fully captured by EA's proposed Rule. For example, Macquarie Generation indicated that operating coal plants between 95% and 105% capacity will accelerate future wear and tear and "will limit plant availability and operating revenues in future periods when outages are brought forward".[123] In relation to gas plants, Macquarie Generation indicates that increased production may result in the accelerated use of contracted gas supplies, which in the longer term "could result in higher prices for gas supply and transportation when contracts are renegotiated".

The NGF and Macquarie Generation also indicates that limiting compensation for generators to EA's list of "direct generating costs" may reduce generators' incentives to generate at a time when they are most needed, that is, during an APP when demand is likely to be tight and when there may be risks to system security and reliability. The NGF hints that this may lead to a situation where generators may choose to be directed by NEMMCO rather than voluntarily participate in the dispatch process during an APP, as there are "clear precedents of generator compensation"[124] following NEMMCO directions.

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[123] Macquarie Generation, 2008. First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 2.

[124] NGF, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 1.

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D Impact of inter-regional flows on the operation of the APC and eligibility for compensation

D.1 Background

This Appendix outlines the impact of inter-regional flows on the operation of the APC and eligibility for compensation.

The impact of inter-regional flows on the operation of the APC was highlighted by TRUenergy-AGL in its first round submission as a source of potential risk and uncertainty for Participants during an APP, as it made forecasting the operation of the APC difficult.[125]

The Commission's analysis of the operation and effect of price scaling during APPs, has been informed by technical advice from Intelligent Energy Systems (IES). IES' final report, 'Regional Settlement Prices During Administered Pricing' was published on the Commission's website on 29 May 2008.[126] The key findings from this report are discussed below.

D.2 How do inter-regional flows impact on the operation of the APC?

As discussed in Chapter 3, under clause 3.14.2(e)(2) of the Rules, the settlement price of regions where the APC has not been applied, can be scaled back during an APP if these regions are exporting power along regulated interconnectors to regions where the APC has been applied. Clause 3.14.2(e)(2) indicates that the regional reference price (RRP) of the exporting region will be scaled back to the product of the importing region's capped price and the average inter-regional loss factor between the exporting region and the importing region. As a consequence, during an APP, price capping may occur in a number of regions and may not be isolated to the region where the APC has been directly applied.

The application of the APC and price scaling as per clause 3.14.2(e)(2) of the Rules is not done by NEMMCO within the NEM Dispatch Engine (NEMDE), but is done following NEMDE in the settlement process by adjusting the final pricing outputs of NEMDE.[127]

Box 1 below provides a simple example to illustrate the inter-regional impact of the APC.

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125 TRUenergy-AGL, 2008, First round submission- Compensation arrangements under administered pricing Rule change proposal, p. 1.

126 IES' final report, 'Regional Settlement Prices During Administered Pricing', is available on the Commission's website here: http://www.aemc.gov.au/pdfs/reviews/Compensation%20Arrangements%20Under%20Administered%20Pricing/supplementary/000IES%20Final%20Report%20-%20Regional%20Settlement%20Prices%20during%20Administered%20Pricing%20-%20May%202008.pdf

127 IES, 2008, Regional Settlement Prices During Administered Pricing', 29 May, p. iii.

During an APP it is highly likely that price capping will occur in a number of regions where the APC has not been directly applied. This is likely to occur because the region where the CPT has been breached, will almost certainly be importing power from other regions, because the CPT will normally only be breached in a region if there is insufficient supply to meet demand. This can be seen in the events of 17 to 19 March 2008 in South Australia when the CPT was breached and the APC was applied. During this APP, prices in the Victoria, Snowy, New South Wales, and Queensland regions were scaled back at various times, as power from these regions was being exported towards South Australia.[128]

A report published by the Code Change Panel in March 2000, 'VoLL Scaling Report', indicates that the reason why the price is adjusted in regions exporting energy to an APC affected region, is to limit negative settlement residues.[129] However, NEMMCO suggests that if power is being imported from a region where the APC has been applied, "then the regional reference price in the importing region is not affected and significant inter-regional settlement residues are likely to be generated"[130].

Although, if a region where the APC has been applied is exporting power and there are any inter-regional loops (i.e. when a region has power flowing in a loop to a region where the price has been capped), there may be price scaling in adjoining regions. However, the Rules appear to be unclear as to how price scaling should operate if there are loops. [131]

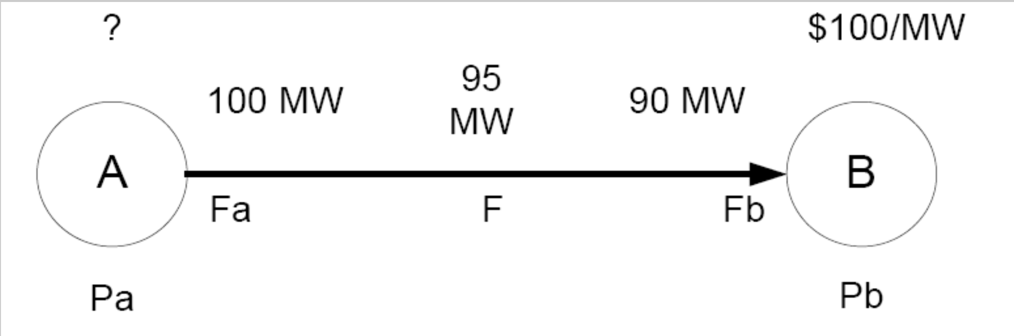
[128] NEMMCO, 2008, Pricing Event Reports- March 2008: 17 March 2008. Available at: http://www.nemmco.com.au/marketandsystemevents/pricing_mar.htm

[129] Code Change Panel, 2000, 'VoLL scaling report, March, p.2. Available at: http://www.neca.com.au/TheCode4827.html?CategoryID=34&SubCategoryID=83-

[130] NEMMCO, 2007, 'Operation of the Administered Price Provisions in the NEM', June, p.3. Available at: http://www.nemmco.com.au/dispatchandpricing/150-0014.pdf

[131] IES, 2008, Regional Settlement Prices During Administered Pricing', 29 May, p. 11-16.

Box 1- Example of the inter-regional impact of the APC



Where:

Pa= RRP of Region A

Pb= RRP of Region B

Fa= Flow of electricity at the regional reference node (RRN) of Region A

Fb= Flow of electricity at the RRN of Region B

F= Flow of electricity at the border of Region A and Region B

In this example Region A and Region B are connected by a regulated interconnector and Region A is exporting power to Region B. The CPT has been breached in Region B and the RRP in Region B has been capped at $100/MWh.

The flow of electricity at the RRN of Region A is 100 MW and the flow of electricity at the RRN of Region B is 90 MW. Therefore there is 10 MW of losses between Region A and Region B.

To determine the scaled back RRP of Region A, the average inter-regional loss factor between Regions A and B must be multiplied by the RRP of Region B.

To reduce negative settlement residues between Regions A and B, the average inter-regional loss factor can be calculated by dividing the flow of electricity at Region A with the flow of electricity at Region B.

Therefore:

Pa= (Fa/Fb) × Pb

= (90 MW/ 100 MW) × $100/MWh

= $90/MWh

Source- IES, 2008, Regional Settlement Prices During Administered Pricing', 29 May, p. 6.

D.3 How do inter-regional flows impact on eligibility for compensation?

The Commission considers that the operation of clause 3.14.2(e) is material to EA's Rule change proposal, as it not only creates market uncertainty as to how it will affect the application of the APC (as highlighted by TRUenergy-AGL), it also potentially increases the number of Participants which are eligible for compensation following an APP.

Clause 3.14.6 of the Rules sets out the types of Market Participants that are eligible for compensation following administered pricing, and the circumstances in which they are able to claim compensation. Clauses 3.1.4.6(a)-(a3) indicates that Scheduled Generators, Scheduled Network Service Providers, Market Participants which submitted a dispatch bid, and ancillary service generating units and loads, may claim compensation if "due to the application" of administered pricing their resultant spot price/revenue is less than the price specified in their dispatch offer/bid for that trading interval.

The Commission considers that the wording in clause 3.14.6(a)-(a3) of the Rules is sufficiently broad to enable Participants in interconnected regions where the APC has not been directly applied, to seek compensation following an APP if their resultant spot price/revenue is less than the price specified in their dispatch offer/bid for that particular trading interval.

The application of clause 3.14.2(e)(2) of the Rules may result in Participants in an interconnected region being dispatched when their dispatch offer price exceeds the adjusted price. Therefore, as Participants in regions where the APC has been directly imposed and Participants in interconnected regions are both potentially adversely affected by the application of the APC, the Commission considers that there is no reason for discriminating the payment of compensation between these two classes of Participants merely on the basis of their location. Further, as the average inter-regional loss factor that is applied to the APC is likely to be a value less than one, it is likely that Participants in regions where the APC has not been directly applied may receive lower settlement prices than Participants in regions where the APC has been directly applied.

However it is also possible that the application of price scaling will result in the administered price in an exporting region being higher than the importing region's administered price. Technical advice received from IES suggests that this can occur when there are negative losses for the flow on the interconnector between the exporting and importing regions.[132] IES indicates that this actually occurred during a dispatch interval at around 5:00 pm on 17 March 2008 in Victoria, when the scaled price was above $100/MWh (i.e. above the APC in SA).

The Commission also considers that the language of clause 3.15.10 of the Rules, which sets out the payment of compensation by Market Customers following administered pricing, is sufficiently broad to impose a compensation-funding obligation on Market Customers who purchased electricity in an interconnected region. Clause 3.15.10 indicates that Market Customers who purchased electricity

[132] IES, 2008, Regional Settlement Prices During Administered Pricing', 29 May.

from a region "affected" by the APC are required to pay compensation. As these Market Customers would have benefitted from reduced prices in their region, it is consistent that these Market Customers should also have the obligation to pay compensation to those Participants located in their region who received reduced settlement prices.

D.4 What is the impact on EA's Rule change proposal?

EA does not refer to clause 3.14.2(e)(2) in its Rule change proposal, nor does it seek to amend this clause in its proposed Rule in Appendix 2 of its proposal. It is unclear whether this omission is deliberate or whether EA is unaware of clause 3.14.2(e)(2) and the impact it may have on eligibility for compensation and the consequential financial risks arising from uplift payments.

The Commission's interpretation of clauses 3.14.2(e)(2) and 3.14.6 of the Rules and the interaction between them is material to EA's Rule change proposal as an increase in the number of eligible Participants for compensation will also naturally increase the potential size of any compensation payment and the financial risks of retailers who are required to fund these compensation payments. Moreover, the financial risks arising from compensation uplift payments would potentially be spread to retailers operating in regions other than the one to which the APC has been directly applied. This may increase the risks of retailer insolvency and hence market wide risks, following an APP. It also reduces the possibility of a combined generator-retailer ('gentailer') offsetting the need to pay compensation in its retail portfolio, with the profits made in its generation portfolio from selling uncontracted capacity on the spot market, in the lead up to the application of the APC.

It should also be noted that EA's proposed Rule seeks to restrict compensation based on "direct generating costs" to Scheduled Generators only.

Therefore, if EA's Rule change proposal is implemented, it would have no effect on the compensation provisions following administered pricing which apply to:

- Scheduled Network Service Providers;
- Market Participants;
- Ancillary service generating units; and
- Ancillary service loads.

These parties, including those located in regions where the settlement price has been indirectly affected by the operation of the APC, would be unaffected by EA's proposed Rule change. Therefore, these parties would continue to claim compensation under the current compensation provisions as per clauses 3.14.6 (a1), (a2), and (a3) of the Rules.

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E Breach of the CPT and the application of the APC in South Australia

The CPT was breached for the first time since the NEM commenced in SA on 17 March 2008. An APP was put in place by NEMMCO in SA from 5:30 pm on 17 March 2008 till 4:00 am on 19 March 2008.[133]

E.1 Contributing factors to the CPT breach in SA

This breach of the CPT followed a sustained period of extreme prices in SA, triggered by 15 days of consistently high temperatures above 35 degrees, the longest ever heatwave for any Australian capital city.[134] On 17 March Adelaide and Melbourne recorded high temperatures of 40 degrees and 38 degrees respectively. The AER indicates that these conditions led to unprecedented demand levels in SA, with a new daily demand record of 3077 MW set in SA on 17 March.[135]

Graph 1 below outlines the maximum daily demand, spot price and cumulative price in the lead up to the CPT breach and following the CPT breach from 4 to 19 March 2008 in SA. As shown in Graph 1, although the maximum daily demand was consistently high over this period, the spot price varied greatly. It appears that for most of the period the spot price in SA was below $400/MWh, but a number of price spikes close or at VoLL served to push the rolling seven day cumulative price close to the CPT on a number of occasions and beyond the CPT on 17 March.

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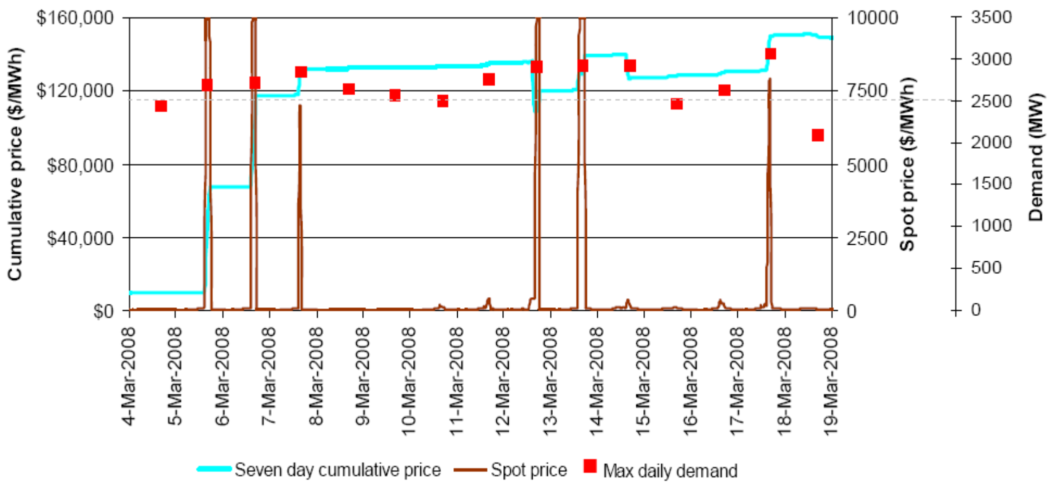
133 NEMMCO, 2008, Pricing Event Reports- March 2008: 17 March 2008. Available at: http://www.nemmco.com.au/marketandsystemevents/pricing_mar.htm

134 AER, 2008, Spot prices greater than $5000/MWh: South Australia 5-17 March 2008, May, p. 2.

135 Ibid.

Graph 1- Seven day rolling cumulative price, spot price and the maximum daily demand in South Australia 4-19 March 2008[136]



The Rules require the AER to investigate and report on any instances in the NEM where the spot price exceeds $5000/MWh. The AER has completed a report on the high price events during the 4 to 19 March 2008 period in SA. It confirms that strong demand alone did not contribute to the breach of the CPT. Rather, the AER suggests that bidding behaviour by AGL significantly contributed to the high price events in SA and the breach of the CPT. The AER also suggests that limited network availability was a contributing factor.

In its report, the AER notes that AGL's Torrens Island power station is the marginal Scheduled Generator in SA, as when demand in SA exceeds 2500 MW, Torrens Island power station must be dispatched. More information on the Torrens Island power station can be found in the First Final Report by the AEMC on the Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia.[137]

Limited network availability on interconnectors between SA and Victoria also appears to have contributed to the high price events in SA over March 2008. The AER notes that a maximum of only 360 MW could be imported into SA along the Heywood interconnector in March 2008, following reductions in the import limit by ElectraNet SA, the SA transmission network service provider (TNSP) in late 2007. In a voltage stability limit constrained the flow on the Murraylink interconnector to less than 100 MW over March 2008.[138] Therefore, the combined maximum import limit

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[136] Source: AER, 2008, Spot prices greater than $5000/MWh: South Australia 5-17 March 2008, May, p. 6. Available at: http://www.aer.gov.au/content/item.phtml?itemId=719801&nodeId=fc25a27d51e2543b5aed6899e31dfbd2&fn=Prices%20above%20%245000/MWh%20report%20-%205%20to%2017%20March%202008.pdf

[137] AEMC 2008, Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, First Final Report, 19 September 2008, Sydney.

[138] NEMMCO, 2008, 'Pricing Event Report- March 2008: 12 March 2008'. Available at: http://www.nemmco.com.au/opreports/pricing_mar.html

into SA along the Heywood and Murraylink interconnectors was less than 450 MW during March 2008. The AER notes that this is considerably less than the 700 MW that was sold to Market Participants through the inter-regional settlement residue auction (IRSA) process.[139]

The import limit into SA was also further reduced by around 260 MW along the Heywood interconnector on 12 March, following a lightening strike which led to the simultaneous trip of the Tailem Bend to Tungkillo and the Tailem Bend to Cherry Gardens 275 kV lines. NEMMCO notes that this contingency, combined with strong demand and bids close to VoLL by AGL's Torrens Island power station for a significant amount of its capacity, led to spot prices near VoLL for two hours on 12 March 2008 in SA.[140] The AER indicates that this incident led to the cumulative price remaining above $120,000.

Further discussion on contributing factors which may lead to high price incidents can be found at **Appendix B.**

E.2 Price scaling across the NEM during the administered price period

During the APP in SA from 17 to 19 March 2008, the energy and frequency control ancillary service prices in the SA region were capped at $100/MWh between 7:00 am and 11:00 pm on business days and $50/MWh at all other times.[141] NEMMCO's Pricing Event Report indicates that during the APP, energy prices in SA were capped for 50 dispatch intervals.[142] For these 50 dispatch intervals, where there was an inter- regional flow from neighbouring regions towards the SA region, the energy price in neighbouring regions was also scaled back, in accordance with clause 3.14.2(e) of the Rules.

Clause 3.14.2(e) of the Rules indicates that the price of regions will be scaled back, if these regions have energy flowing along regulated interconnectors towards a region where the APC has been applied. Clause 3.14.2(e) outlines that the regional reference price of the exporting region will be scaled back to the product of the importing region's capped price and the average inter-regional loss factor between the exporting region and the importing region.

As a result of clause 3.14.2(e) of the Rules, the energy price in Victoria, Snowy, New South Wales, and Queensland was scaled back at various times during the APP.[143] NEMMCO indicates in its Pricing Event Report that the scaling that occurred during the APP reduced prices by nominal amounts only.[144] As can be seen in **Graphs 2 and 3** below, it appears that spot prices reached a maximum of around $180/MWh

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139 AER, 2008, Spot prices greater than $5000/MWh: South Australia 5-17 March 2008, May, p. 4.

140 NEMMCO, 2008, 'Pricing Event Report- March 2008: 12 March 2008'

141 As noted above the Commission amended the APC schedule in May 2008. The APC is currently set at $300/MWh in all regions for all time periods.

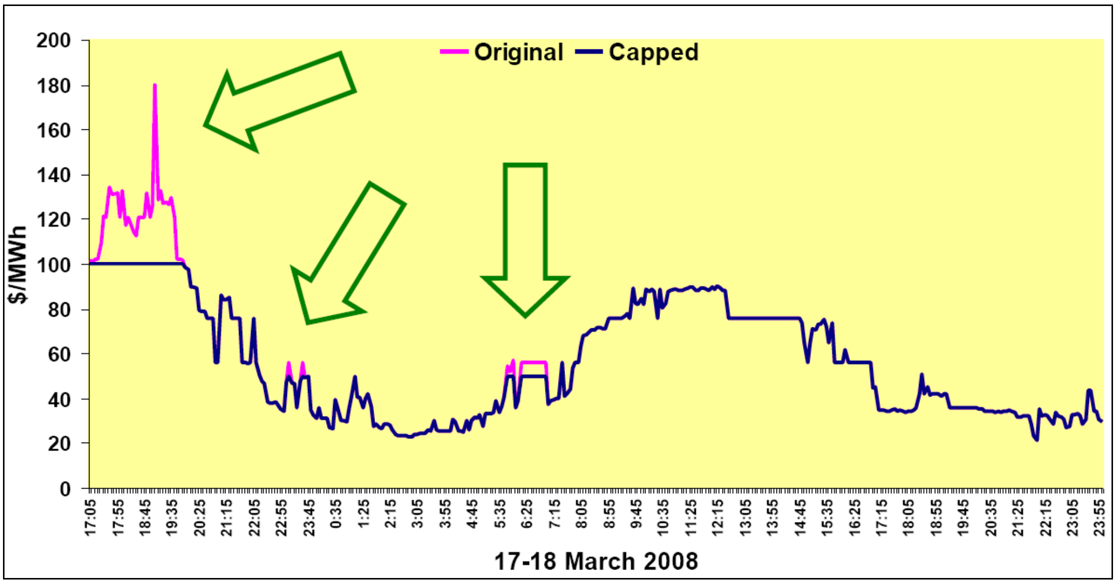
142 NEMMCO, 2008, Pricing Event Reports- March 2008: 17 March 2008.

143 Ibid.

144 Ibid.

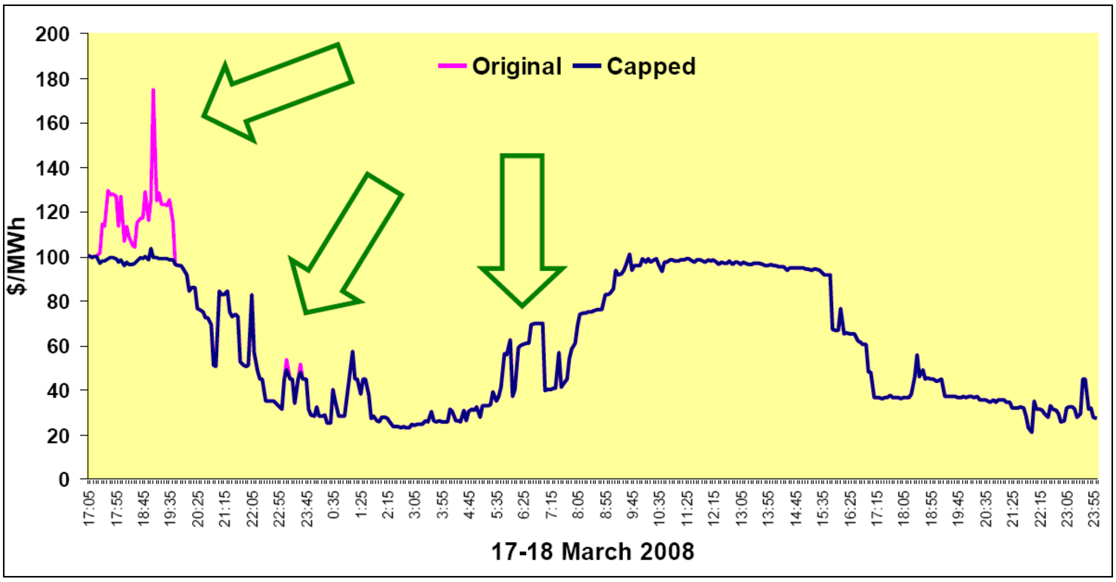
during the APP, prior to being capped. These graphs also demonstrate that there were only a small number of trading intervals where the price was capped by NEMMCO (trading intervals where the price has been capped are highlighted by the arrows). Therefore, for the majority of the trading intervals during the APP it appears that in SA and Victoria that bids and offers were below the APC. Further discussion on the impact of inter-regional flows on the operation of the APC can be found in **Appendix D.**

Graph 2- Spot prices in South Australia 17-18 March 2008[145]



[145] Source: NEMMCO, 2008, Administered Price Event March 2008, Presentation to NEM Forum #84, 24 April. Available at: http://www.nemmco.com.au/about/057-0376.pdf

Graph 3- Spot prices in Victoria 17-18 March 2008146



E.3 No claims for compensation following the administered price period

The Commission and NEMMCO did not receive any claims for compensation, following the application of the APC in SA in March 2008. As a consequence, no compensation was awarded by the Commission for this incident. By the time the CPT was breached on the afternoon of 17 March, the heatwave in SA was ending and as a result demand for electricity was falling (see Graph 1 below). This is likely to have had a dampening effect on the SA spot price during the APP. It is likely that if spot prices had been significantly higher during the APP (e.g. $1000/MWh rather than $180/MWh), then the likelihood of compensation claims being lodged may have been increased.

146 Ibid.

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F Issues raised in second round submissions

F.1 Background

This appendix contains a summary of the key issues raised in second round submissions received by the Commission on EA's Rule change proposal.

On 25 September 2008, the Commission gave notice under section 99 of the NEL of the making of the draft Rule determination and draft Rule. Second round submissions closed on 7 November 2008.

The Commission received two second round submissions, which were from the following organisations:

- The Energy Retailers Association of Australia (ERAA);
- Origin Energy

Copies of these submissions are available on the Commission's website.

F.2 Key issues raised in second round submissions

The main issues that were raised in submissions include:

- The appropriateness of the draft Rule;
- The inclusion of opportunity costs in the compensation calculation; and
- The scaling of prices in adjoining regions.

These issues are discussed in further detail below.

F.2.1 Appropriateness of the draft Rule

Submissions from both ERAA and Origin Energy supported the draft Rule in its current form. Specifically ERAA noted that the Rule change would remove much of the uncertainty associated with determining compensation.[147] Similarly Origin Energy stated that the Rule change would bring clarity and transparency to the process for calculating compensation during an APP.[148]

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147 ERAA, 2008, Second round submissions – Compensation Arrangements Under Administered Pricing – Draft Rule, p. 1.

148 Origin Energy, 2008, Second round submissions – Compensation Arrangements Under Administered Pricing – Draft Determination, p. 1.

F.2.2 Opportunity costs

Both ERAA and Origin Energy have noted in their submissions that the opportunity cost calculation has the potential to be complex. Accordingly ERAA has requested that the Commission develops a clear process for calculating opportunity costs. [149]

Origin Energy on the other hand has indicated support for the Commission's proposed approach to developing the guidelines. [150] This approach is based on the Transmission Consultation Procedure Guidelines and imposes the requirement for public consultation when developing the guidelines.

The Commission also received comments, not in the form of a formal submission, which outlined a possible method for calculating opportunity cost in a simple and transparent manner. Other things being equal, these are desirable features of a methodology for calculating compensation. However, the appropriate route to consider this issue is the consultation process on the guidelines.

F.2.3 Scaling of prices in adjoining regions

In their submission, Origin Energy expressed the opinion that scaling back prices in adjoining regions during an APP to limit the accrual of negative inter-regional settlement residues may be inefficient. [151] The basis for this opinion is that price scaling broadens the group of potential claimants for compensation following the imposition of an APP.

To resolve this problem, Origin Energy has requested that the Commission investigate other options to manage negative IRSR during an APP. In particular, Origin Energy has requested greater consideration of the IES proposal, such that the APP would only be applied in regions where the CPT has been breached.

The Commission recognises that price scaling may increase the pool of potential claimants and accordingly the resulting size of compensation payments. However the Commission maintains its position expressed in Appendix A.2.5, whereby any changes to price scaling require further investigation and consultation to examine the potential consequences of the change, and that the appropriate vehicle for this investigation is a separate Rule change proposal.

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149 ERAA, 2008, Second round submissions – Compensation Arrangements Under Administered Pricing – Draft Rule, p. 1.

150 Origin Energy, 2008, Second round submissions – Compensation Arrangements Under Administered Pricing – Draft Determination, p. 1.

151 Origin Energy, 2008, Second round submissions – Compensation Arrangements Under Administered Pricing – Draft Determination, p. 1.

F.2.4 Other issues

The Commission also received comments, not in the form of a formal submission, on the issue of how the administrative cost associated with processing a compensation claim were to be recovered. The Commission noted these comments, but remains of the view that it is appropriate for the Commission to have the discretion to recover administrative costs from the parties who are claiming compensation.

G Draft National Electricity Amendment (Compensation Arrangements under Administered Pricing)

National Electricity Amendment (Compensation Arrangements under Administered Pricing) Rule 2008 No. 17

under the National Electricity Law as applied by:

(a) the National Electricity (South Australia) Act 1996;

(b) the Electricity (National Scheme) Act 1997 of the Australian Capital Territory;

(c) the National Electricity (New South Wales) Act 1997 of New South Wales;

(d) the Electricity - National Scheme (Queensland) Act 1997 of Queensland;

(e) the Electricity - National Scheme (Tasmania) Act 1999 of Tasmania;

(f) the National Electricity (Victoria) Act 2005 of Victoria; and

(g) the Australian Energy Market Act 2004 of the Commonwealth.

The Australian Energy Market Commission makes the following Rule under the National Electricity Law.

John Tamblyn

Chairman

Australian Energy Market Commission

National Electricity Amendment (Compensation Arrangements under Administered Pricing) Rule 2008 No. 17

1. Title of Rule

This Rule is the *National Electricity Amendment (Compensation Arrangements under Administered Pricing) Rule 2008 No. 17*.

2. Commencement

This Rule commences operation on 1 January 2009.

3. Amendment of the National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 1.

Schedule 1 Amendment of National Electricity Rules

(Clause 3)

[1] Clause 3.14.6 Compensation due to the application of an administered price, VoLL or market floor price

Omit clauses 3.14.6(b), (c), (d) and (e), and substitute:

(b) Notification of an intention to make a claim under paragraphs (a), (a1), (a2) or (a3) must be submitted to both *NEMMCO* and the *AEMC* within 5 *business days* of the *trading interval* in which *dispatch prices* were adjusted in accordance with clause 3.9.5 or notification by *NEMMCO* that an *administered price period* or period of *market suspension* has ended.

(c) The *AEMC* must, in accordance with the *transmission consultation procedures*, develop and *publish* guidelines ('compensation guidelines') that:

(1) identify the objectives of the payment of compensation under this clause as being to maintain the incentive for:

(i) *Scheduled Generators, Scheduled Network Service Providers* and other *Market Participants* to invest in *plant* that provides services during peak periods; and

(ii) *Market Participants* to supply *energy* and other services during an *administered price period*;

(2) require the amount of compensation payable in respect of a claim under this clause to be based on:

(i) the costs directly incurred by the claimant due to the application of the *administered price cap*, *VoLL*, the *market floor price* or the *administered floor price* (as the case may be); and

(ii) the value of any opportunities foregone by the claimant due to the application of the *administered price cap*, *VoLL*, the *market floor price* or the *administered floor price* (as the case may be);

(3) outline the methodology to be used to calculate the amount of any compensation payable in respect of a claim under this clause, including the methodology for calculating the costs referred to in

clause 3.14.6(c)(2)(i) and the value of opportunities foregone referred to in clause 3.14.6(c)(2)(ii); and

(4) set out the information *NEMMCO* and a claimant must provide to enable a panel established under paragraph (g) to make a recommendation as to compensation under this clause and to enable the *AEMC* to make a determination as to compensation under this clause.

(d) The *AEMC* must request the *Adviser* to establish a three member panel from the group of persons referred to in clause 8.2.2(e) and such other persons as the *Adviser* may choose to appoint under clause 8.2.6A(i) to assist the *AEMC* to develop the compensation guidelines.

(e) The *AEMC* must *publish* the first compensation guidelines by 30 June 2009 and there must be such guidelines in place at all times after that date.

(f) The *AEMC* may from time to time, in accordance with the *transmission consultation procedures*, amend or replace the compensation guidelines.

(g) Following its receipt of a notification under paragraph (b), the *AEMC* must request the *Adviser* to establish a three member panel from the group of persons referred to in clause 8.2.2(e) and such other persons as the *Adviser* may choose to appoint under clause 8.2.6A(i) to make recommendations to the *AEMC* as to whether:

(1) compensation should be payable by *NEMMCO* in relation to the claim; and

(2) if so, the amount of compensation that should be paid.

(h) The panel must, as soon as practicable but not later than:

(1) 30 *business days* after receiving the information required to be provided to it under the compensation guidelines, give to the *AEMC* a report that sets out its draft recommendations as to the matters referred to in paragraph (g); and

(2) 20 *business days* after the closing date for submissions on that report, give to the *AEMC* a report that sets out its final recommendations as to the matters referred to in paragraph (g).

(i) Not later than 20 *business days* after receiving a report referred to in subparagraph (h)(1), the *AEMC* must *publish*:

(1) that report;

(2) its draft decision as to the matters referred to in paragraph (g); and

(3) an invitation for written submissions to be made to the *AEMC* on that report and the *AEMC's* draft decision.

(j) Any person may make a written submission to the *AEMC* on the report referred to in subparagraph (h)(1) and the *AEMC's* draft decision within the time specified in the invitation referred to in subparagraph (i)(3), which must not be earlier than 20 *business days* after the invitation is *published*.

(k) In preparing a report that sets out its final recommendations, the panel must take into account the submissions made in response to the invitation referred to in subparagraph (i)(3).

(l) In preparing a report under paragraph (h), the panel must apply the compensation guidelines.

(m) In making its draft decision as to the matters referred to in paragraph (g), the *AEMC* must take into account the draft recommendations of the panel.

(n) Not later than 15 *business days* after receiving a report referred to in subparagraph (h)(2), the *AEMC* must *publish*:

(1) that report; and

(2) its final decision as to the matters referred to in paragraph (g).

(o) In making its final decision as to the matters referred to in paragraph (g), the *AEMC* must take into account:

(1) the final recommendations of the panel; and

(2) the submissions made in response to the invitation referred to in subparagraph (i)(3).

(p) In making a draft or final decision under this clause, the *AEMC* must apply the compensation guidelines unless it is satisfied that there are compelling reasons not to do so.

(q) The *AEMC* may recover from a claimant for compensation under this clause any costs that are incurred by the *AEMC* and the panel in carrying out their functions under this clause in respect of that claim. For this purpose the *AEMC* may require the claimant to pay all or a proportion of those costs to the *AEMC* prior to the claim being considered or determined.

[2] Chapter 11 Savings and Transitional Rules

After rule 11.23, insert:

Part T Compensation Arrangements under Administered Pricing

11.24 Rules consequential on the making of National Electricity Amendment (Compensation Arrangements under Administered Pricing) Rule 2008

11.24.1 Definitions

In this rule 11.24:

Amending Rule means the National Electricity Amendment (Compensation Arrangements under Administered Pricing) Rule 2008.

commencement date means the date the Amending Rule commences operation.

11.23.2 Compensation Guidelines

All actions taken by the *AEMC* prior to the commencement date in anticipation of the commencement date for the purposes of developing and *publishing* the first compensation guidelines as required by clause 3.14.6(e) are taken to satisfy the equivalent actions required for compensation guidelines under clause 3.14.6(f).

END OF RULE AS MADE