concept economics

REPORT

RISK ASSESSMENT OF ALTERNATIVE COMPENSATION OPTIONS

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AEMC

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EXECUTIVE SUMMARY

The AEMC has asked Concept Economics ("Concept") to assess the impact of three alternative mechanisms for compensating market participants during an administered price period on the financial risks faced by different participants. These three alternatives are:

a. Compensation based on "direct operating costs, i.e. short run marginal costs (SRMC) excluding opportunity costs;

b. Compensation based on SRMC including the opportunity costs of fuel restricted plant, such as hydro and gas; and

c. Compensation based on the bids and offers of market participants.

Compensation is one of the following four mechanisms that the National Electricity Market (NEM) design has put in place to limit the risks arising from sustained high prices, which may in turn threaten solvency and viability of the NEM and its participants:

1. A spot price cap known as the value of lost load (VoLL) and a price floor;

2. A cumulative price threshold (CPT) that applies over a rolling seven day period and that triggers an administered price period when breached;

3. An administered price period (APP), during which an administered price cap (APC) applies to settlements in the region where the CPT was breached, while settlement prices in other regions exporting towards the APC region are scaled back towards the APC level using the average loss factors on each interconnector; and

4. A compensation mechanism for eligible parties (generators, scheduled loads, MNSPs, IRSR unit holders) that are affected during the APP.

Each of these four elements has been the subject of recent reviews. However, it is the fourth element – i.e. the compensation mechanism – that is the focus of this report. In particular, the AEMC is in the process of considering a National Electricity Rule ("Rule") change to compensation provisions submitted by EnergyAustralia ("EA"). EA has argued that there are four main flaws with the current compensation provisions, namely that:[1]

- The criteria for determining compensation under clause 3.14.6 of the Rules are open to interpretation so that actual compensation arrangements are uncertain;

- The compensation arrangements in place may affect market behaviour and provide adverse incentives for market participants;

[1] EnergyAustralia, "EnergyAustralia's rule change request, Compensation provisions due to the application of an administered price, VoLL or market floor price", 10 December 2007.

- Retailers are required to pay their share of the compensation to generators whose costs exceed the administered price, and these compensation payments cannot be hedged by retailers, creating a source of financial risk; and

- The process for determining compensation lacks transparency, and fails to clearly delineate the role of the AEMC and the expert panel.

EA proposes that these concerns be addressed in a Rule change that would:

- Remove existing references to the difference between the capped spot price and a generator's offer price, and stipulate that the purpose of any compensation payable to a Schedule Generator is to recover direct costs only;

- Remove the reference to a generator's offer price in the compensation criteria; and

- Require the AEMC to publish the expert panel's report and the AEMC's proposed determination on compensation and consulting on these matters.

In combination, EA expects these measures to reduce the likelihood of unreasonably high administered price cap compensation arrangements.

Against the backdrop of concerns with existing compensation arrangements and its proposed changes to compensation provisions, this study reviews the pros and cons of the three alternatives developed by the AEMC.

There has only been a single occasion so far in the NEM when the CPT was breached — 17 March 2008 in the South Australian region. Given that no compensation claims were made by any party following this event, there is little history to provide any guidance on the merits or drawbacks of current compensation arrangements, which are offer based. Instead, predictions as to the impacts of the three alternative compensation arrangements described above (i.e. a, b, c) must rely upon a conceptual analysis of each of these arrangements and their likely impacts, supported by the results of empirical modelling.

CONCEPTUAL ASSESSMENT

We first conceptually evaluate the likely implications of compensation arrangements, at a broad level, for the various market participants, especially generators and retailers. We find that compensation creates different and conflicting risks for different participants:

- Compensation payments expose retailers to an unhedgeable risk. A compensation mechanism that involves higher levels of compensation payments will therefore expose retailers to relatively greater risk.

- On the other hand, a form of compensation that renders lower payment and more certainty to a retailer may create risks for a generator if this undermines full cost recovery.

- Other market participants would also be exposed to risks that are similar to generator risks. For example, a demand side bidder may have significant costs that APC and the chosen form of compensation may not fully cover for. Demand side measures may cost several thousand of dollars per MWh and therefore may cause significant losses for a demand side bidder during an APP. Scheduled Network Service Providers (NSP) or Inter-regional Settlement Residue (IRSR) unit holders face significant revenue at risk if the interconnector revenue or settlement residues they are expected to earn based on uncapped prices are severely diminished due to the application of an APC.

A balanced approach that recognises these conflicts is essential. A specific evaluation of the three alternative forms of compensations suggests that:

- While compensation based on direct operating costs would definitely lower the risks faced by retailers, this approach may not be economically efficient because:
  - It will not reflect opportunity costs to generators, including those associated with:
    - a) Limited energy, such as hydro or limited gas, that could be used in other periods, or
    - b) Deferring maintenance and sourcing fuel at a higher than normal cost; and
  - It ignores fixed costs, including start-up costs and fixed O&M costs (although the potentially limited number of administered price hours may mean that these additional costs are low).
- Compensation based on opportunity costs overcomes some of the theoretical limitations of the direct cost approach, but in practice is fraught with the difficulty of estimating opportunity costs.
- Bids and offers by demand side bidders and generators could be used as a basis for compensation. While this approach overcomes the shortcomings of an approach based on direct operating costs, it adds a significant potential problem that is raised in the EA proposal, namely, that it may lead to high bids/offers and, at the extreme, may effectively negate the very purpose of a CPT.

A combination of bidding strategy and dispatch optimisation models is used to develop quantitative estimates of compensation for each of these three options. An important feature of these models is that they capture the impact of CPT on bidding behaviour, namely, a relatively high CPT would encourage the generators to bid more aggressively with a lower risk of breaching the CPT. A related issue that forms the basis for our modelling approach therefore is to understand the incentives generators face in terms of whether in fact to breach the CPT – thereby triggering an APC and compensation – or whether to stay within the CPT limit. We explain intuitively why generators may not seek to breach the CPT, illustrating the underlying reasoning with a simple numerical example. We then present some (albeit very limited) supporting evidence based on the analysis undertaken recently by the Australian Energy Regulator (AER) that corroborates our intuitive assessment. As noted below, the model design incorporates the incentives and anticipated behaviours just described, including by imposing an explicit CPT constraint on cumulative price outcomes.

To summarise, a conceptual assessment of compensation arrangements allows us to determine the likely risks that the various market participants will face under each of the three compensation arrangements. Formal modelling is then undertaken, incorporating NEM data, which supports the conclusions drawn from our conceptual assessment, and enables us to determine the likely magnitude of risks faced by the various market participants under each of the three compensation arrangements.

MODELLING APPROACH

The market modelling includes the simulation of generator bids, dispatch/price optimisation and simulation of uncertain events such as high demand and/or outages that leads to extreme price risks.

Although the objective of this report is to evaluate the merits of alternative compensation mechanisms, it is clear that the modelling approach must capture interdependencies between compensation arrangements and other components of the overall risk management package (VoLL, CPT, APC). For instance, the level of CPT affects the amount of compensation payable, with a higher CPT lowering the risk of APP and hence compensation risk.[2]

In addition, it must accurately capture the incentives that market participants face, and how this is likely to impact on the behaviour of market participants. This is especially important in respect of the likely bidding behaviour of generators (noted above) when the market is subject to stress conditions, which is when risk management measures will come into play. It is important to note that the model is designed specifically to simulate and predict outcomes that would arise under the various compensation options *in the event of extreme circumstances* – e.g. persistent high demand, very low hydro storage and massive disruption to gas supply throughout the NEM – because, although rare, these are the very types of events which, in combination with other factors such as aggressive generator bidding strategies, are likely to cause an APP.[3] Since this presents a significant risk to purchasers of energy, the veracity of the chosen compensation mechanism needs to be tested under such extreme events to avoid a systemic financial risk for purchasers of energy.

Our theoretical and empirical modelling captures all of these important elements. Briefly summarising the modelling approach, demand function parameters have been calibrated using actual demand, price and dispatch data.[4] We have then used a bidding optimisation

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2 In this respect, it is worth noting that both AGL and TRUenergy have each made submissions to substantially raise the level of CPT. If the CPT is to be maintained, AGL believes that the threshold trigger should be doubled to $300,000 per accumulation period – i.e. the CPT level that was originally proposed by the Reliability Panel in 1999. TRUenergy also supports an increase in the CPT to $300,000.

3 This specific focus is reflected in the data used in the modelling. Given this objective of the modelling exercise, it is important that modelling results presented should be interpreted carefully in this specific context, and should not be generalised to a wider context.

4 We have assumed a probability distribution around the actual demand, i.e., demand varies for each half-hour on either side of the actual demand. Calibration of the demand function refers to deriving a relationship between demand and prices using historical demand and price data. Further discussion on the approach to calibration is included in Appendix B.

using a combination of Cournot, Bertrand and perfect competition (PC) paradigms. The bidding optimisation allows for generators to rebid during high demand periods. Once the bids are optimised, dispatch is simulated for a range of uncertain demand, energy availability and outage conditions using Monte Carlo simulation. Volatility of spot prices derived from these simulated outcomes is then used to assess the financial risks faced by generators, retailers and MNSP/IRSR holders.

An important aspect of the modelling is that generators explicitly take into account the "CPT limit" as a constraint in preparing their offer volumes and prices. This requires a "look ahead" using expected demand and strategies adopted by other generators. The bidding optimisation model captures these details over a weekly timeframe to derive bids for each half-hourly period of the week. An illustrative example is used to explain how a binding CPT limit may influence generator behaviour.

Our modelling contains limitations, both due to the complexity of the task at hand, as well as given the time constraints for the modelling exercise. In short, the modelling approach relies on short-term modelling only, does not consider frequency control ancillary services (FCAS), and covers only two recent high price events. The model assumes that price volatility is driven by the combination of generator behaviour and physical drivers such as demand, hydro energy, generator and interconnector outages and gas supply interruptions.

Our analysis is confined to two recent high price events, when the CPT was breached or nearly breached, namely:

- March 11-17 in 2008, when SA experienced a series of high price events that led to breaching the CPT on March 17 around 5:30 pm; and

- June 12-18 in 2007, when NSW among other regions experienced very high prices with cumulative prices exceeding $120,000 for the week, although the CPT was not breached.

Analysis of these two weeks, although limited, provides a good basis for understanding the general behaviour of prices driven by some of the key drivers. Analyses conducted by AER show, in both instances, demand was identified as one of the key drivers, but there were other related factors, including generator bidding that exacerbated spot prices.[5]

[5] AER, "Spot prices greater than $5000/MWh, South Australia: 5 - 17 March 2008". May, 2008. AER, *Prices above $5000/MWh in the National Electricity Market: June 12 to June 28 2007.*

The SA price event in March 2008 was a relatively localised phenomenon that led to more extreme prices and was primarily caused by a combination of high demand and extreme bidding behaviour by some of the local generators. The high price event in NSW in June 2007, in comparison, was much more widespread. Prices in QLD were also high. Both NSW and QLD price excursions were caused by a combination of high demand and plant unavailability due to water restrictions. The effect of plant unavailability is reflected by the generally higher prices maintained throughout the week in addition to short duration price spikes. Some generators in NSW exhibited extreme bidding behaviour that led to a significant number of observed price excursions. Overall, the events in these two weeks provide a reasonable basis for analysing most of the physical and behavioural drivers. We have also undertaken assessment of extreme events such as major NEM-wide gas curtailment and shortage of water, albeit based on simplistic assumptions, to illustrate the potential volatility around compensation assumptions.

While the modelling serves the purpose of augmenting the conceptual analysis in highlighting some of the major areas of risk, we recognise its limitations both on the limited number of events studied and the simplicity of some of the modelling assumptions around extreme events. Given the limited time of less than four weeks available to undertake the analysis described in this report and a primary focus in this report on a conceptual assessment of changes to market design parameters, we have restricted the volume of data and computation to the bare minimum. We have relied on simplifying assumptions where there is very limited information available (e.g. in relation to gas generation curtailment) to form meaningful scenarios, in order to provide some indication of the nature of risks underlying such events. The focus of the modelling approach in this report is therefore on deriving broad insights and indicative estimates of risks for key scenarios, and ensuring the transparency of assumptions and analysis, using two recent high price events, as opposed to a highly detailed analysis of every single five minute period and a large number of scenarios for several months/years.

MODELLING RESULTS

Our modelling indicates that each of the three compensation arrangements creates different risks for the various market participants. Based on our simulation of an extreme event, we infer that:[6]

- Offer based compensation may, under such an extreme scenario, yield a compensation payment that is an order of magnitude higher compared to direct cost based compensation; and

- Depending on the nature of uncertainty, each of these two forms of compensation can vary. However, direct cost based compensation has significantly less volatility compared to an offer based counterpart.

This suggests that the offer based compensation option can expose retailers to a significant level of risk.

[6] Based on a simulated event that extends high demand periods for an additional 4 hours on March 17, 2008.

We have also conducted an indicative assessment of opportunity costs for storage water and limited gas availability and demonstrated that an opportunity cost based approach to compensation may give rise to similar risks to offer based compensation. Specifically:

- Opportunity cost for storage hydro may vary a great deal, potentially being equal to:
  - Zero or near zero, in the event the additional hydro energy would simply go waste (i.e., be spilled), if it is not used in the current time period;
  - Marginal cost of baseload coal/gas generation, say below $50/MWh;
  - Marginal cost of a peaking plant running on gas or oil between $50/MWh to $350/MW;
  - Marginal cost of demand side alternatives that may be up to $3,000/MWh; and
  - Marginal cost of unserved energy or VoLL.
- If hydro generation is being used during the APP, a compensation using opportunity cost may therefore be anywhere in this range, although is more likely to be at the higher end of costs.
- Similarly, a widespread disruption of gas supply may cause spot prices to be extremely high, especially in regions that rely heavily on gas for peaking duty. Hence, the opportunity cost for the limited volume of available gas may be extremely high. As a consequence, the compensation payment may be very high, rendering the APC package to be ineffective in capping NEM-wide financial risk under such circumstances. Such compensation payments may however hinge critically on the nature of the contingency, namely the size and duration of gas supply interruption. Thus, our experiments suggest that if there is just enough gas available to avoid load shed events, the opportunity costs – and hence value of the compensation – may rapidly decline.

Table 1 summarises the merits and drawbacks of the three compensation options.

Table 1 Comparison of Compensation Options

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 risk 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 compensation uplift payments 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 administered price period may be high, creating a risk for energy purchasers – potentially yielding the highest compensation payments. Again, large and uncertain compensation uplifts payments that cannot be hedged by retailers may lead to systemic market-wide risk.

We have also analysed the implications of compensation arrangements for scheduled network service providers (NSP). Compensation payable to scheduled network service providers (NSP) is a function of the rent collected on an interconnector, calculated using the uncapped and capped price differences. Exercise of market power by generators to induce an offer-based compensation has an impact for NSPs. Depending upon how localised the high prices are, some NSPs may potentially claim very high compensation. In particular:

- If high prices are relatively concentrated in a single region, such as the March 2008 price event, an application of APC under the current Rule leaves the potential for a high compensation in that region. In particular, generators in the region may have an incentive to rebid to raise the uncapped prices that will inflate the difference in rent between before and after the price capping. Offsetting this, any high compensation may be confined to this region, rather than spreading to other regions. In particular, scaling of prices will not "spread" this impact to other regions, because prices will generally stay low both before and after any price capping. The rent difference for other regions will also therefore be low.

- A price event similar to the one in June 2007 poses a bigger challenge because, in the event the CPT is breached, prices in several regions are affected and scaling prices implies potentially all generators and interconnectors in the NEM are eligible to claim compensation.

With regard to this second issue, we have analysed a second-order risk that may arise due to an indirect impact on regional prices caused by price scaling that is applied to avoid negative settlement residues. If APC is applied in one region, scaling of prices in other regions creates indirect second-order risks for retailers, to the extent that generators and NSPs outside the APC-region are also eligible for compensation payments. In particular, scaling may spread the impact of APC across multiple regions if they are connected through a sequence of regulated interconnectors with flow directions towards the APC-region.

Since this has the impact of spreading the risk of a high and uncertain compensation payment across a wider region, an alternative approach is not to scale prices for other regions and let negative settlement residues accrue over interconnectors. This helps to confine the regional price risks to the APC region alone. However, retailers in a non-APC region then face either of the following risk outcomes, depending upon whether or not prices are scaled:

- **If prices are scaled**, the spot prices are lowered but the compensation payments can potentially be high. High and volatile compensation presents a significant risk because this cannot be hedged using the contracts that are linked to spot prices; whereas

- **If prices are not scaled**, spot prices will continue to be high, which presents a high spot purchase risk for an unhedged retailer. In addition, there may also be negative settlement residues on interconnectors. Depending upon whether these costs are passed on to retailers and, further, whether retailers are allowed to pass through such costs to customers, this may also present an additional cost risk to retailers.

CONCLUSIONS

The compensation option that uses direct operating costs only is by far the simplest and the most transparent option. However, it is unlikely that this option alone can be relied upon for all types of generators because it does not deal with fixed costs and opportunity costs, which comprise a significant share of costs for some generators.

That said, the other two options considered open up significant risk issues for purchasers of energy because they render compensation payments to be potentially both very high and volatile, which may in turn lead to systemic market-wide failures. Caution is therefore needed before embarking on either one of these two options. In the worst case, a high compensation that is not reflective of costs incurred by generators renders the CPT-APC mechanism ineffective. In particular, we note that:

- Opportunity cost based compensation has a theoretically sound basis, but appropriate data and modelling processes need to be developed and tested to render it an economically efficient and transparent means of compensation; and

- Offer based compensation potentially provides generators with incentives to alter their bids/offers during an APP (i.e., once the CPT breach is known). Appropriate measures need to be in place – which may potentially require changes to the market Rules, so as to limit the extent of rebidding during an APP – in order for this option to be viable.

The selection of compensation options needs to recognise that:

- Direct operating cost based compensation is not adequate. Although it offers better transparency, simplicity and certainty relative to the other two options, some consideration of fixed costs and opportunity costs is essential.

- Process and Rules need to be developed/modified for other options. Both opportunity cost and bid/offer based compensation open up significant risk issues from a retailer perspective. Compensation payments can be both very high and volatile for extreme system conditions. Care is therefore required to develop processes and Rules that mitigate such risks.

Finally, although price scaling avoids a negative settlement residue, it potentially exposes retailers all over the NEM to a high and uncertain compensation payment that cannot be hedged. If prices across several NEM regions are high, breaching the CPT in one of the regions may result in high compensation payments for all of these regions and therefore constitutes a significant risk to retailers.

1. INTRODUCTION

Volatility of spot prices for both energy and ancillary services is an essential ingredient of the design and operation of the Australian National Electricity Market (NEM). It is needed so that generators (among other market participants) can recover their fixed costs and earn a reasonable return on their assets. However, it also creates risks for wholesale market purchasers, because a persistently high spot price can cause extreme hardship and may jeopardise the existence of the market in an extreme case.

While individual market participants are expected to manage their own risks to suit their appetite for risk, the market design includes some "safety valves" for managing extreme price risks that may, in a worst case scenario, lead to the financial failure of retailers and potentially other participants in the market. NEM design has evolved over the years in this area and currently has four mechanisms in place to limit the risks arising from sustained high prices:

- A spot price cap known as the value of lost load (VoLL) and a price floor;
- A cumulative price threshold (CPT) that applies over a rolling seven day period and that triggers an administered price period when breached;
- An administered price period (APP), during which an administered price cap (APC) applies to settlements in the region where the CPT was breached, while settlement prices in other regions exporting towards the APC region are scaled back towards the APC level using the average loss factors on each interconnector; and
- A compensation mechanism for eligible parties (generators, scheduled loads, MNSPs, IRSR unit holders) that are affected during the APP.

These four elements comprise an overall package within the market rules ("Rules") for managing the risks that sustained high prices could pose to the solvency and viability of the NEM and its participants. This package was conceived by the Reliability Panel and NECA in 1999-2000, and approved by the ACCC in 2000. This package of measures replaced the Force Majeure (FM) provisions that had existed prior to that date, and which were meant to address the same issue.

Each of these four elements has been the subject of recent review. However, it is the fourth element that is the focus on this report. In particular, the AEMC is in the process of considering a Rule change to compensation provisions submitted by EnergyAustralia ("EA"). EA has argued that there are four main flaws with the current compensation provisions, namely that:[7]

- The criteria for determining compensation under clause 3.14.6 of the Rules are open to interpretation so that actual compensation arrangements are uncertain;

[7] EnergyAustralia, "EnergyAustralia's rule change request, Compensation provisions due to the application of an administered price, VoLL or market floor price", 10 December 2007.

- The compensation arrangements in place may affect market behaviour and provide adverse incentives to market participants;

- Retailers are required to pay their share of the compensation to generators whose costs exceed the administered price, and these compensation payments cannot be hedged by retailers, creating a source of financial risk; and

- The process for determining compensation lacks transparency, and fails to clearly delineate the role of the AEMC and the expert panel.

EA proposes that these concerns be addressed in a Rule change that would:

- Remove existing references to the difference between the capped spot price and a generator's offer price, and stipulate that the purpose of any compensation payable to a Schedule Generator is to recover direct costs only;

- Remove the reference to a generator's offer price in the compensation criteria; and

- Require the AEMC to publish the expert panel's report and the AEMC's proposed determination on compensation and consulting on these matters.

In combination, EA expects these measures to reduce the likelihood of unreasonably high administered price cap compensation arrangements.

Against the backdrop of concerns with existing compensation arrangements and its proposed changes to compensation provisions, the AEMC has asked Concept Economics ("Concept") to assess the impact of three alternative compensation mechanisms on the financial risks faced by different participants, these being:

a. Compensation based on "direct operating costs:, i.e. short run marginal costs (SRMC) excluding opportunity costs;

b. Compensation based on SRMC including the opportunity costs of fuel restricted plant, such as hydro and gas; and

c. Compensation based on the bids and offers of market participants.

As explained in the remainder of this report, each of these three approaches has its merits and drawbacks. In particular, each approach has the potential to differ substantially in terms of the financial risks they confer upon different market participants. We have undertaken a conceptual assessment, augmented with market modelling, to derive insights on these issues.

1.1. STRUCTURE OF THIS REPORT

The structure of the remainder of this draft report is as follows:

- Section 2 briefly provides a backdrop to the current review of compensation arrangements. It first explains the inherent risks in the NEM, and why they arise. It then explains how each of the four components of the overall risk management package, including the compensation mechanism, combine to manage these risks;

- Section 3 conceptually evaluates the likely implications of compensation arrangements, for the various market participants, at both a broad level, as well as with respect to each of the three alternative compensation arrangements;

- Section 4 sets out the formal modelling approach adopted to determine the likely magnitude of risks faced by the various market participants under each of the three compensation arrangements;

- Section 5 presents the results of the modelling undertaken; and

- Section 6 provides concluding remarks.

2. NEM DESIGN AND INSTITUTIONAL CONTEXT

This section explains why volatility is an inherent feature of the NEM, and how this creates risks for market participants. It then summarises provisions in the NEM design intended to contain *extreme* price volatility risks, of which a compensation mechanism is an integral component of the package of risk management mechanisms currently in place.

2.1. MARKET RISKS

The NEM is an energy-only market. Generators submit supply offers on a $/MWh price and are paid the uniform regional market clearing price for their output. Retailers and large customers purchasing from the spot market must correspondingly pay the regional market clearing price for any energy they purchase from the spot market. All electricity wholesale markets must address two essential market characteristics that necessarily follow from the physics of electricity, which are that:

- The supply side cannot store its output. Thus, there are circumstances when demand is unusually high or when generation/transmission outages occur, and when demand cannot be met; and

- On the demand side, with few exceptions, customers are generally unresponsive to short term prices, and will not and/or cannot reduce demand in response to very high prices. In addition, on an alternating current (AC) network, the flow of power to individual customers cannot be controlled with any degree of precision.

In combination, this means that there are circumstances when consumers effectively demand electricity no matter what the price, and no market clearing price in the classical sense exists. The result is that electricity spot prices are inherently volatile and responsive to (very) short-term market and physical events (e.g., equipment outages and network congestion), which in turn create risks for all market participants:[8]

- On the supply side, generators face a risk of low prices, which undermine full cost recovery and investment incentives; while

- On the purchasing side, retailers (on behalf of small customers) and large customers are exposed to very high price events that can potentially lead to “infinitely” high spot prices if the market is not artificially cleared.

In other words, while high prices are a source of financial risk to retailers, expected market prices and profits from generation are central to driving investment. The NEM market design does not incorporate additional payments for generation capacity or availability, and generators must recover the fixed (capital) costs of plant from differences between the

[8] There are related indirect risks, for instance, caused by the influence of spot prices on contract prices, cost of insurance, etc. that also affect market participants.

market clearing price and their variable generating costs, referred to as short-run profit, scarcity rent, or “infra-marginal rent”.[9]

As a typical regional price duration curve in the NEM for any year reveals, the inframarginal revenue that a peaking plant could expect to earn during a particular year varies enormously depending on the number of price spikes. These spikes, which we have referred to as “super peak”, may provide a significant part of revenue available to pay for the plant’s fixed costs. A generator faces a “net revenue” risk, in that it recovers its fixed cost only when market prices are above the plant’s variable cost. From the perspective of investors – especially in peaking plants – price volatility is essential for them to recover their costs and this is a crucial risk issue that also needs to be adequately addressed in determining the optimal compensation arrangement.

2.2. NEM RISK MANAGEMENT MECHANISMS

In combination, supply and demand characteristics of wholesale electricity markets require regulatory determinations of price limits to deal with circumstances when the market cannot clear, or where prices are such that the resulting financial consequences would materially undermine the continued operation of the market and its participants. That regulatory policy determines the magnitude and also the duration of price spikes.

The market Rules contain a number of key mechanisms that are designed to limit risks to individual market participants and systemic market wide risks.[10] VoLL, CPT, APC and Compensation in combination with the market floor price, define the price envelope within which supply and demand are balanced in the wholesale spot market, and capacity is delivered to meet the demand.[11] Briefly summarising the first three components of the risk management package:

- **VoLL** is currently set at $10,000/MWh. VoLL is a crucial market parameter because it provides signals for supply and demand-side investment and usage. For example, if the cap is set too high, consumers (either via their retailers or trading directly in the market themselves) can be financially exposed. If the cap is set too low, there may be insufficient incentives to invest in new generation capacity to meet future reliability due to the risk of fixed costs not being able to be adequately recovered.

9 There are two provisos to this statement. The NEM has separate markets for a range of ancillary services, some of which are now integrated with the energy market. Generators can earn additional revenues through sales of ancillary services, but at least for baseload/intermediate plant, such revenues tend to be immaterial compared to revenues from energy sales. NEM generators can elect to sell their output via the spot market or via the contract market. However, these markets are closely linked, and in the medium to longer term, average price outcomes in both markets would be expected to be the same.

10 In addition to the “direct” risk management mechanisms that we discuss here, there are other indirect mechanisms in place that also help mitigate financial risks, namely prudential requirements, designated retailer of last resort for retailers, and settlement rules that limit collection risk.

11 The market floor price is a price floor on regional reference node prices. The current value of the market floor price is -$1,000/MWh.

- The **CPT** is a trigger defined in the National Electricity Rules for initiating an APC period. Under the current arrangements an APC is invoked by NEMMCO if the cumulative half-hourly price over a seven day period exceeds $150,000, corresponding to an average spot price of approximately $446/MWh over the seven previous days. The CPT was designed to replace previous *force majeure* triggers based on load shedding events.

- An **APC** is a regime triggered by a number of conditions set out in the Rules, including circumstances in which the CPT has been breached.[12] Under current arrangements, an APC is invoked once the CPT breaches $150,000. The APC applies in regions undergoing extreme market events, and automatically sets the price of dispatch to a value determined by the AEMC. Once invoked, the relevant trading periods become 'administered price periods' (**APP**). This cap applies at least until the end of the current trading day. The rules provide for the AEMC to publish and update a schedule of APC values.[13] The schedule for the APC was amended by the AEMC in May 2008, where it was set at $300/MWh for all regions in the NEM, for all time periods.

- The final component of the risk management package, which is the primary focus of this report, is a **compensation mechanism**. Generator compensation arrangements allow scheduled generators to seek compensation when their offer price for any cleared offer during an APP is higher than the APC. "Constrained-on" generators with offer prices higher than the APC are eligible for compensation if the resultant spot price payable to dispatched generating units in any trading interval is less than the price specified in their dispatch offer for that trading interval.[14] Other market participants that can also claim compensation following an APC are Scheduled Network Service Providers, Market Participants, and ancillary service generating units and loads. Compensation is determined by the AEMC based on advice from an expert panel.

As apparent from the discussion above, each of the components of the overall risk management package is closely interrelated. The CPT, APC and Compensation arrangements are especially interrelated, in that, if half-hourly prices in a region on a rolling 7-day basis exceed the CPT, an APP is declared with prices in the region capped to the APC. Perhaps most relevantly, the level of CPT affects the amount of compensation payable. For instance, a high CPT would lower the risk of APP and hence compensation risk.

There are two other related details associated with these mechanisms that should be noted:

- Prices in other regions exporting to the region are scaled back using an average loss factor to avoid all instances of negative inter-regional settlement residues;[15] and

12 See National Electricity Rules 3.14.1-3.14.2. http://www.aemc.gov.au/electricity.php?r=20071105.151356.

13 http://www.aemc.gov.au/electricity.php?r=20071106.104606.

14 See National Electricity Rules, Clause 3.14.6.

15 Rule 3.14.2(e).

- Dispatch volumes during an APP continue to be calculated based on the normal procedure using bids/offers and an uncapped, or normal, RRP is also calculated. This uncapped RRP is overwritten with an administered price for the purpose of spot market settlements.[16]

If the administratively capped settlement price is less than the price specified in a dispatched offer/bid, then the dispatched party is able to claim compensation on the relevant volume dispatch.

As a package, these instruments are intended to strike a balance between:

1. Containing extreme price risk for those who buy energy, while

2. At the same time, providing liberal allowances to ensure that investment in peaking generation is not curtailed. In fact, the original proposal from the Panel was to set the CPT high enough for a peaking generator to recover up to 300 per cent of its annual capital requirement but this was subsequently reduced to 150 per cent.[17] During an APP, the APC is set for all generators (including those at the expensive end) to recover their operating costs.

The issue of balance has been raised by the market participants from time to time. In this respect, it is worth noting that both AGL and TRUenergy have each made submissions in respect of the appropriateness of having a CPT and, to the extent that there should be a CPT, the level at which the CPT (and APC) should be set.[18] Thus, AGL sees the CPT as a market interference that suspends capital returns to suppliers, where such interference can distort market signals and, in extreme cases, lead to market failure. AGL therefore believes the CPT in its current form should be removed. Instead, AGL suggests that the market should rely on existing hedging mechanisms, with retail price caps being abolished to ensure the retailers are not caught between high wholesale costs and unreasonably constrained retail prices. If the CPT is to be maintained, AGL believes that the threshold trigger should be doubled to $300,000 per accumulation period – i.e. the CPT level that was originally proposed by the Reliability Panel in 1999 – on the basis that no rigorous analysis had been undertaken to justify any deviation from the original CPT level. TRUenergy also supports an increase in the CPT to $300,000. Amongst other things, TRUenergy believes that the VoLL and CPT should be increased with a defined time frame, subject to a review after five years. It further believes that the cap, if triggered, should be applied for a full quarter.

AGL and TRUenergy have also noted the problem of keeping the APC too low because it does not give sufficient incentive for many generators to operate and thereby endangers system security.[19] They have also noted that a low APC would increase the number of compensation claims and hence the administrative burden. They have therefore noted the need for a balance between maintaining the level of APC at a small fraction of the VoLL

16 As defined by Rule 3.14.6.

17 ACCC Final Determination – Application for Authorisation: VoLL, Capacity Mechanisms and Price Floor, 20 December 2000.

18 AGL and TRUenergy, *Joint Submission to Clarification of Schedule of Administered Price Cap*, January, 2008.

19 AGL and TRUenergy, *ibid*.

while, at the same time, ensuring it is not too low. They favour increasing the APC to $500/MWh, although supported the increase of the APC to $300/MWh by the AEMC in April, 2008.

While these instruments attempt to contain market wide risk, they also create dispatch/pricing anomalies that have adverse consequences, namely that:

- First, dispatch and settlement prices are no longer aligned, which may distort economic signals and affect generator behaviour;
- Second, prices and dispatch in regions that do not have a binding CPT are affected because of price scaling;
- Third, compensation claims can, in theory, spread across the entire market because of the price scaling; and
- Finally, compensation claims create significant uncertainty for all concerned parties, and associated risks are difficult to manage. Since the cap and other contracts that a retailer may hold to manage its risk under normal conditions (i.e., when prices are not capped to the APC) cannot hedge the risk of potentially high and volatile compensation payments, this is a significant risk factor that needs to be carefully assessed to understand the level of exposure under extreme scenarios.

Application of APC affects all market participants, including:

- Generators, because it lowers their revenue and creates uncertainties on recovery of fixed costs;
- Retailers, because it increases their spot purchase costs in the short term and costs of hedges in the long term;
- Scheduled NSPs, who are exposed to inter-regional price differences; and
- Traders, who take position on arbitrage opportunities.

The preceding discussion has highlighted the risks inherent in the NEM, and the particular risks that different market participants are susceptible to. As apparent from the discussion above, the inability for generators to earn revenues from high price periods undermines full cost recovery and investment incentives. On the purchasing side, retailers (on behalf of small customers) and large customers are exposed to very high price events that can potentially lead to “infinitely” high spot prices if the market is not artificially cleared. An effective compensation mechanism therefore needs to balance the conflicting incentives and financial risks faced by generators and retailers.

2.3. ADMINISTERED PRICES IN MARCH 2008

There has only been a single occasion so far in the NEM when the CPT was breached. As will be explained, this limited experience provides little guidance as to the optimal compensation alternative.

A March 2008 price event resulted in SA prices being capped for 11 half hour periods on 17-18 March.[20] The price event is described below, and is one of two price events that forms the basis of our empirical modelling. Table 2 shows the difference between uncapped and capped spot prices for these periods. The average price difference was relatively low at $12.51 and the maximum difference was $37.04. Prices had subsided by the evening of March 17 when the heatwave ended. The gap between uncapped and capped prices was low after the breach occurred.

Table 2 Administered and Uncapped Spot Prices in SA

	Uncapped	Capped	Difference
17/03/2008			
5:30PM	$ 106.18	$ 100.00	$ 6.18
6:00PM	$ 128.26	$ 100.00	$ 28.26
6:30PM	$ 119.15	$ 100.00	$ 19.15
7:00PM	$ 123.38	$ 100.00	$ 23.38
7:30PM	$ 137.04	$ 100.00	$ 37.04
8:00PM	$ 109.66	$ 99.72	$ 9.94
11:30PM	$ 46.58	$ 45.62	$ 0.96
18/03/2008			
12:00AM	$ 42.14	$ 41.19	$ 0.95
6:00AM	$ 45.66	$ 43.42	$ 2.24
6:30AM	$ 49.61	$ 45.79	$ 3.82
7:00AM	$ 55.72	$ 50.00	$ 5.72
AVERAGE			$ 12.51

Source: AER, Spot Prices Greater than $5000/MWh, Appendix E, 2008.

As the AER analysis shows, the high price events leading up to the CPT breach were driven largely by extreme bids by Angaston and Torrens Island on March 17 and, once these offers were priced low and generation increased, the uncapped prices dropped quickly from several thousand dollars to around $100/MWh. In fact, SA prices remained low for the remainder of the month and averaged $32/MWh from the morning of March 18 through to March 31.

Our own market simulations confirms that compensation during these 11 periods, if any, would have been relatively small given how close the capped and uncapped prices were, and also, given that the direct operating costs of majority of stations in SA – including those of Torrens Island and some gas turbines – are well below $100/MWh, which was the peak period APC at the time.[21] As far as we are aware (based on the publicly available

[20] As a result, VIC, Snowy, NSW and QLD prices were also scaled for a few periods.

[21] The off-peak APC was $50/MWh.

information), there were no issues with limited fuel/gas supply in SA in that period and hence no opportunity costs attributable to limited energy. It is possible that there were gas off-takes that exceeded contractual obligations, such as exceeding the maximum daily quantity (MDQ) or maximum hourly quantity (MHQ). However, detailed information on individual contracts is not available in the public domain. We also note that the planning studies undertaken by the Electricity Supply Industry Planning Council (ESIPC) suggest there is ample physical (MDQ/MHQ) capability in the SA gas supply system to meet peaking requirements.[22] According to AEMC, no compensation claims were made by any party following the event, which seems consistent with the relatively low price gap, observed bidding behaviour and cost structures.

Given that no compensation claims were made by any party following this event, there is little history to provide any guidance on the merits or drawbacks of offer based compensation. Instead, predictions as to the impacts of the three alternative arrangements described above must rely upon a conceptual analysis of each of these arrangements and their likely impacts, supported by the results of empirical modelling. This analysis is contained in the remaining sections.

[22] ESIPC, *Annual Planning Report*, 2004-2008. ESIPC states the current total MDQ of MAP and SEAGas pipelines in excess of 900 TJ/day with an MHQ of approximately 38 TJ/hour. Allowing for up to 200 TJ/day for domestic use, this leaves over 700 TJ/day for electricity generation. Long term planning analysis conducted by ESIPC estimates this MDQ/MHQ will be adequate for peak day supply up to 2014. ESPIC estimates for 2008 peak day and hour are below 500 TJ/day and 30 TJ/hour, respectively. While this does not necessarily reflect all possible contingency conditions, it reflects there is sufficient physical MDQ/MHQ capability in the system to deal with additional gas supply that may be needed.

3. CONCEPTUAL ASSESSMENT OF COMPENSATION OPTIONS

Before we present the formal modelling approach, we first conceptually evaluate the likely implications of compensation arrangements, in terms of the likely risks each of the three candidate compensation arrangements is likely to confer upon various market participants:

- Sub-section 3.1 considers the different impact that compensation, at a broad level, is likely to have on various market participants, especially generators and retailers;
- Sub-section 3.2 considers the specific impacts that each of the three arrangements may have on these market participants.

Finally, given the close interrelationship between the CPT and compensation (i.e. breaching the CPT triggers APC and compensation), a key issue is to understand the incentives generators face in terms of whether in fact to breach the CPT or whether to stay within the CPT limit. In sub-section 3.3, we explain intuitively why generators may not seek to breach the CPT, illustrating the underlying intuition with a simple numerical example. We then present (albeit very limited) evidence based on AER's analyses that corroborates our intuitive assessment.

3.1. IMPLICATIONS OF COMPENSATION FOR MARKET PARTICIPANTS

In combination with a binding APC, compensation payments will form the total payment to a generator during an APP. As foreshadowed above, changes to compensation arrangement proposed by EA may potentially have substantial impacts on risks faced by market participants, including retailers, generators and NSPs.

Retailer risks can be summarised as follows**:**

- The amount of compensation payable, or the size of the uplift for retailers, is uncertain. The method of compensation chosen has a significant bearing on the magnitude and volatility of any compensation payable. However, irrespective of the particular method of compensation chosen, there always exists an uncertainty as to the type of generation support needed during an APP, and the associated costs of this support. The dispatch MW and cost of generation makes the compensation uncertain;
- Hedge contracts that a retailer may possess will be referenced to the regional spot price, which will reflect the APC rather than compensation payment. Therefore, retailers will not in effect be able to hedge their compensation payment related risks;
- Compensation payments are likely to follow periods of high price volatility, if not extreme price volatility, prior to the APP. Any resultant substantial and unhedgeable compensation payment may expose retailers to a significant cash flow risk in the short term; and

- In the long term, a retailer may or may not be able to pass through these additional costs to customers depending on the regulatory framework in place.

In summary, depending upon their magnitude and frequency, compensation payments may place pressure on a retailer's balance sheet in the long term, in the event they cannot pass through the costs, in addition to creating a short term cash flow risk. While maintaining a portfolio of contracts will help a retailer to hedge its risk for normal periods, compensation payments will not be amenable to such form a of risk management.

Generator risks can be summarised as follows:

- A generator faces a risk of being constrained on and receiving a price that is below even its short term direct operating costs. For instance, a generator running on liquid fuel may have short term fuel costs in excess of $300/MWh. Given that the APC was, until recently, set at $100/MWh for peak periods, this would not have enabled such a generator to recover its fuel costs, let alone other costs (e.g. fixed costs and opportunity costs);

- There may be added costs. For instance, there may be a need for a generator to run at a level that is not efficient from a technical perspective, which would give rise to additional operating costs or increased wear and tear on machinery and other equipment. Some generators may also be forced to run during a previously scheduled maintenance period, leading to significant wear and tear. If APPs occur frequently, this will impact heavily on peaking investment to the extent the resultant APC and compensation - especially compensation based on direct costs alone - does not yield a reasonable return for such investments. Generators may also need to incur costs to source additional fuel, at a higher cost than their normal fuel supply contracts for running above the expected level. Finally, generators with a limited energy capability (e.g. hydro) may have to forego profitable future opportunities by generating during an APP. This has significant implications for any compensation method that entitles generators to recover opportunity costs in addition to any direct operating costs;

- Finally, there is a collection risk because of potential delays in payment for a review by the expert panel/AEMC and any dispute that may arise in the process.

Other market participants would also be exposed to risks that are similar to generator risks. For example, a demand side bidder may have significant costs that APC and the chosen form of compensation may not fully cover for. Demand side measures may cost several thousand of dollars per MWh and therefore may cause significant losses for a demand side bidder during an APP. NSPs or IRSR unit holders face significant revenue at risk if the interconnector revenue or settlement residues they are expected to earn based on uncapped prices are severely diminished due to the application of an APC. Compensation measures for these participants also need to address an appropriate basis of costs or market based arrangements so that they do not suffer losses.

There is clearly a conflict among the risks faced by different participants. Compensation payments expose retailers to an **unhedgeable risk**. A compensation mechanism that involves higher and uncertain levels of compensation payments will therefore expose retailers to relatively greater risk. On the other hand, a form of compensation that renders lower payment and more certainty to a retailer may not suit a generator if this undermines full cost recovery. A balanced approach that recognises these conflicts is essential.

3.2. COMPARISON OF ALTERNATIVE COMPENSATION MECHANSIMS

We have explored these issues around three forms of compensation based on:

1) Direct operating costs (SRMC);

2) Direct operating costs plus opportunity cost; or

3) Bid/offer based compensation.

AEMC's terms of reference identified three options to compensate generators for effectively being constrained on during an administered price period because:

1 The actual direct operating costs, namely fuel and variable O&M costs, may exceed the administered price (or the scaled price if the generator is in a different region where prices needed to be scaled down to avoid negative settlement residues). This form of compensation constitutes a lower bound on the level of compensation. From the perspective of retailers, this option not only yields the lowest level of compensation payable, but is also the one that is most transparent and certain;

2 In addition, generators may need to be compensated for any short to medium term opportunity costs – in particular, for stored water, or limited available gas, that could be profitably employed in periods beyond the APP and their direct operating costs may reflect at best a small fraction of the value of such energy. For instance, if high temperatures or outages persist/recur in the short to medium term after the APP, prices may rise to VoLL. A MWh equivalent of limited water/gas used during the APP could earn up to VoLL instead of the capped price. In other words, the opportunity cost could add very substantially to the direct operating cost. In extreme cases, compensation based on opportunity cost may be two to three magnitudes higher that compensation based on direct operating costs. Estimation of opportunity costs needs to address certain implementation issues, namely the treatment of fixed costs, inter-temporal unit commitment and limited energy constraints. These issues need to be addressed not only at a conceptual level, but also in terms of how they should be derived in practice and apportioned to individual half hourly periods.[23] Thus, while an approach based on opportunity costs is economically sound, such costs may be both uncertain, and the analytical complexities in deriving estimates may well make them less transparent than direct operating costs; and

[23] Some of these issues barring limited gas/water constraints have been addressed in the context of the Western Australian electricity market in a recent paper by, Adam McHugh, *Portfolio Short Run Marginal Cost of Electricity Supply in Half Hour Trading Intervals*, Technical Paper, Economic Regulation Authority, Western Australia. January, 2008. It should be noted that the term short run marginal costs (SRMC) in this paper implies opportunity costs are part of such costs. The term SRMC is used in the ACIL Tasman report for the NEM generators to imply direct operating costs only.

3 Actual cleared offers/bids may be in excess of the APC. Bids/offers ultimately reflect the commercial position of the generator, including any return needed on its long term investments as well as any economic opportunity costs. Observed generator offer behaviour in the NEM suggests that generators may offer a part of their capacity at prices substantially higher than direct operating costs and even close to VoLL. If these offers are cleared and set the uncapped spot price, the level of compensation can be extremely high, presenting a risk to wholesale market purchasers.

What follows is a summary of how each of these approaches may be implemented, as well as the relative merits and drawbacks associated with each compensation mechanism.

3.2.1. Compensation Based on Direct Operating Costs

Compensation based on direct operating costs is by far the simplest and most transparent form of compensation, although not necessarily an economically efficient outcome.

Calculation of compensation is straightforward and involves calculating the additional cost over and above the APC of any "constrained on" expensive peaking generation. Peaking gas generators in the NEM are estimated to have direct operating costs comprising fuel costs and variable O&M costs of around $60-$70 per MWh, while peaking stations running on oil have much higher direct operating costs of between $270-355 per MWh.[24] Demand side measures also have a wide range of costs, both in the form of fixed and variable operating costs. Callable commercial and industrial (C&I) programs that target large C&I customers to shed load with prior notification are estimated to cost anywhere between $500 and $3,000 per MWh of load reduction.[25] However, a review of actual offers and bids submitted by generators during recent high price events suggest that these direct operating costs are at least an order of magnitude *lower* than bids in most cases.

While compensation based on direct operating costs would definitely lower the risks faced by retailers[26], this approach may not be economically efficient because:

- It will not reflect the opportunity costs of generators with limited energy such as hydro or limited gas that could be used in other periods, or other opportunity costs, such as the opportunity costs to generators of deferring maintenance; and

- It ignores fixed costs, including start-up costs and fixed O&M costs (although the potentially limited number of administered price hours may mean that these additional costs are low).

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24 ACIL Tasman, *Fuel Resource, New Entry and Generation Costs in the NEM*, Final Report Prepared for NEMMCO, September, 2007.

25 CRA International, *Assessing the Value of Demand Response in the NEM*, prepared for the Australian IEA Task XIII Team, November, 2006. Other estimates including the IES study used for ACCC determination reports demand side costs up to $3,000/MWh (ACCC Final Determination – Application for Authorisation: VoLL, Capacity Mechanisms and Price Floor, 20 December 2000, p.33).

26 This issue has been extensively discussed in the EA proposal.

If this is the case, such an approach will discourage generator and demand-side bidders from delivering the appropriate levels of resources needed in the short term and, if APPs occur frequently, the approach may discourage investment in the long term.

3.2.2. Compensation Based on Opportunity Costs

Compensation based on opportunity costs overcomes some of the theoretical limitations of the direct cost approach, but is fraught with the difficulty of estimating opportunity costs in practice.

For instance, the timeframe for such an assessment itself is an issue, since any stored water or limited gas could be used potentially in a number of alternative periods with very different price outcomes. Hence, opportunity costs could range from a very low value close to zero, in the event the stored water would simply go waste if not used at the time, to VoLL, if it could be used later on to avoid load shedding (or replace a high price bid), as well as anywhere in between these two extremes for a vast range of potential demand and system conditions. Similar issues arise in respect of other elements of an opportunity cost calculation, namely, costs associated with start-up, fixed O&M and deferred maintenance.

The model design (described below) has a limited "look ahead" capability and therefore does not explore these issues in full detail. Nevertheless, we have used an inter-temporal dispatch optimisation that explicitly recognises energy limits and that calculates shadow prices for these limits that embody the opportunity costs for limited hydro/gas. Specifically, these shadow prices reflect the alternative usage of an extra MWh of energy in any other period in the week, including replacement of expensive sources of generation, avoided VoLL outcomes and replacement of expensive bids. Opportunity costs are also calculated for a range of probabilistic outcomes around demand and outages.

3.2.3. Bid/Offer Compensation

Bids and offers by demand side bidders and generators could be used as a basis for compensation. While this approach overcomes the shortcomings of an approach based on direct operating costs, it adds a significant potential problem that is raised in the EA proposal, namely, that it may lead to high bids/offers and, at the extreme, may effectively negate the very purpose of a CPT.

In other words, the total payment by a retailer during an APP and the compensation may add up to the spot market purchase cost absent the CPT.[27] This is because the retailers would end up compensating the generators the difference between spot prices that would have resulted absent any CPT and the APC. In such a case, generators would be indifferent to the CPT because they will either receive the spot price if they do not breach the CPT, or equivalent compensation payments in the event they do breach it. That said, as we will explain shortly, there are some theoretical and practical issues that suggest generators will not necessarily choose to breach the CPT and target the maximum level of compensation.

27 For this reason, we refer to spot prices without any CPT as "uncapped" spot prices.

Finally, we note that the three compensation measures discussed above provide a "raw" estimate of compensation which, we understand (from clause 3.14.6 of the rules) is subject to discretion by the expert panel that advises the AEMC and by the AEMC itself, which may further apply its own discretion.[28] This is discussed further below. Depending on the merits of each case, the AEMC may also wish to retain such discretion going forward. This leaves the prospect for the compensation payable to differ from the raw estimates whenever such discretion is applied. Nevertheless, the raw estimates we derive are expected to provide a reasonable indication of the likely range of compensation amounts payable under each of the three potential alternatives. In addition, they are likely to highlight the implementation issues that need to be understood and addressed in embarking on any final approach.

3.3. GENERATOR INCENTIVES TO BREACH THE CPT

An APP and hence potential compensation payment event is triggered by a breach of the CPT. A fundamental issue to understand is the incentives generators face in terms of whether in fact to breach the CPT, thereby triggering an APC and compensation, or whether to stay within the CPT limit. We explain intuitively why generators may not seek to breach the CPT, illustrating the underlying intuition with a simple numerical example. We then present (albeit very limited) evidence that corroborates our intuitive assessment.

3.3.1. Reasons Why generators May Choose Not to Breach the CPT

Breaching the CPT leaves the generator facing the prospect of market prices set on the basis of an APC and a compensation payment. Depending on the adopted compensation mechanism, compensation payments may vary from its direct operating costs to its offer price. Although offer prices may in theory negate the effect of the CPT and enable the generator to earn effectively what it could earn absent the CPT, there are at least four factors that are, in practice, likely to prevent this, namely:

1. Compared to a certain spot price revenue before the CPT is reached, compensation outcomes are uncertain. Specifically, compensation outcomes can be substantially lower if:

    a. Compensation is cost based and such costs are significantly below bids/offers; and/or

    b. Only a small part of the capacity is offered above cost;

[28] See clause 3.14.6 of the Rules.

2. The timing of a CPT breach is unknown since it is ultimately driven by uncertain events, e.g., a deviation of demand from the expected demand, and/or unforeseen outages. At any given point in time, a generator may at best have a view of expected demand and information on availability of competing generators over the next few days.[29] However, it will be extremely difficult, if not impossible, to form an *a priori* estimate of compensation because it requires knowing in advance when a CPT breach might occur.

3. Generators face dispatch risk. Given that compensation is only payable on dispatched volumes that have an offer/bid price greater than the administered price (see Clause 3.14.6), there is a risk that a market participant may fail to maximise its settlement revenues under an APP by seeking to adjust its offers/bids so as to increase any compensation payable on the basis of the difference between the offer/bid price and the administered price. There is a fundamental difference in spot market revenue and compensation payment. Since compensation may be characterised as a "pay as bid", as opposed to the uniform price auction followed in the NEM that sets regional spot prices before the CPT is breached, the underlying bidding strategy would be different for the two regimes. The most important distinction is that in a uniform price auction, a generator need not put as much emphasis on offering a significant part of its capacity at the market clearing price because all of its cleared generation is paid at that price regardless of who sets the price.

4. A compensation payment is not absolutely guaranteed and has less certainty compared to spot market revenue.[30] In other words, uncertainties surrounding a compensation payment will make it difficult for generators to compare alternative revenue streams from (a) the spot market without breaching the CPT, vis-à-vis (b) the spot market plus compensation payments once the CPT is breached.

Each of these considerations suggest that a generator may in fact prefer not to breach the CPT. This incentive is consistent with albeit very limited anecdotal evidence on the observed actual market behaviour of generators (see below), and can be further demonstrated using the following simple numerical example.

3.3.2. A Simple Numerical Illustration of Generator Incentives

Suppose there are three generators, each with 100 MW capacity with short run marginal costs (SRMC) of $10, $50 and $350 per MWh. Expected demand is 240 MW. Regardless of

29 There will be better information and hence more certainty closer to the time when a CPT breach actually occurs, e.g., there may be pre-dispatch information on the day indicating a potential breach later in the day. This will enable generators to change their offering strategy, for instance, through rebidding. However, this will be a point in time when the generator has essentially already made many of the decisions on their generation offer, including the key decision over whether to stay within the CPT limit, or breach it, that we are discussing here. Put differently, we are specifically seeking here to determine any impact of changing the CPT may have on a (rolling) seven day horizon basis, and how generators may potentially target market price outcomes over the entire period.

30 We understand that the current market rules contain some provisions that enable discretion to be applied regardless of the basis (i.e., cost or bid/offer based compensation) on which compensation amounts are calculated. Firstly, the expert panel deciding the compensation may apply some discretion in advising the AEMC on the value of compensation to be paid. AEMC may further use discretion in determining the final value of compensation to be paid and also reserves the right to retain such discretion for any future compensation.

the exact demand level realised, all the generators know that they can withdraw their capacity and raise prices up to VoLL, as would a forced outage of any of the three generators.[31]

A typical offering strategy under that circumstance would be that each generator offers a part of their capacity well above their SRMC potentially close to VoLL. For example, each generator could choose to offer 20 MW of their capacity at $1,000/MWh taking into account what their rivals might do.[32]

Generators would typically bid the rest of their capacity well below $1,000/MWh and probably at their SRMC to get dispatched. The spot price will be set at $1,000 MWh regardless of whose bid is cleared and all three generators receive this price.

A compensation payment, in contrast, does make depend on which generator's bid is cleared. The cheaper generators in an APP will receive no compensation at all if their expensive bid is not cleared. Assuming an APC of $100/MWh, the expensive generator will be guaranteed to receive some compensation because it has an SRMC higher than the APC.[33] Since the generators have an expectation of the spot price and rival firms' cost structures, it is likely that during an APP i.e., when they know CPT has been breached they will take this information into account and bid at a price at least higher than $100/MWh; if not bid the entire capacity close to their expectation of highest marginal cost (i.e., $350/MWh) or equilibrium price (i.e., $1000/MWh), in order to maximise compensation.[34]

Regardless of which of these strategies they choose, it is not hard to see that generators' total net revenue from APC would diverge widely from the sum of APC plus compensation whenever the expected spot price is substantially higher than the APC, and that the associated profit maximising solutions would require them to bid differently, if not very differently, in these situations.

Contractual obligations would discipline this behaviour to some extent, but if demand is sufficiently high, the majority of the generators would be prepared to accept the relatively low dispatch risk, rather than risk losing out on what may be a very substantial compensation payment. That said, compensation payments generally would be more uncertain and a generator would also need to consider this in forming a view on its *expected* compensation

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31 This is an extreme assumption but unusually high demand periods may lead to such situations as some of the price events in SA in March demonstrated. See for example, AER's analysis of March 2008 events – Figure 2 of the AER report shows any demand above 2,500 MW gave some of the larger generators ability to driver prices high.

32 That is, the offer price and volume will reflect some form of expected equilibrium outcome that is based on expected rival strategies. The offer price and volume would also depend on a range of other actors, including contractual obligations, elasticity of demand, competition from the demand side and imports from other regions. If we assume a demand curve: Spot Price = $10,000 – 40*(Total Generation), the Nash equilibrium price in this case assuming no contracting, imports, DSM, etc. is $2,600/MWh, and the three generators offer between 40 to 50 MW at that price to maximise their profit. If we assume, however, that the first two generators with lower cost are heavily contracted at 80 MW and the third generator has a lower contract of 50 MW, the Nash equilibrium price decreases to $500/MWh with much less capacity being offered at high price.

33 Using the current APC level of $300/MWh does not change any of the general conclusions deduced from the analysis.

34 This will be a typical outcome in a "pay as bid" or discriminatory auction and has been a well documented critique of the British electricity market reform. See for example, Catherine Wolfram, *Electricity Markets: Should the Rest of the World Adopt the UK Reforms?*, University of California Energy Institute, 1999. Wolfram, among others, has argued that a discriminatory auction would encourage generators to bid more aggressively than they would in a pool or uniform auction.

payment. Taking an extreme case, if all three generators decided to bid all of 100 MW around $1,000/MWh, they all face a risk of an uncertain compensation payment because only two of them may get fully dispatched, while the third generator may only supply 40 MW.[35] Compensation payments for all generators may vary between $36,000 (($1,000-$100)*40 MW) and $90,000 (($1000-$100)*100 MW = $90,000). Any variation in demand would increase this uncertainty, e.g., if actual demand turned out to be 210 MW, the lower end of compensation would be only $9,000.

In contrast, under a uniform auction setting, the generators need to bid a smaller quantum at a high price to ensure that a $1000/MWh settlement price is achieved for all of its cleared generation volumes.

In summary, given the pervasive uncertainty around whether and when a CPT breach would occur, a generator with some degree of (transient) market power effectively has to choose between targeting an outcome that prevents a CPT from being triggered, as opposed to an outcome whereby the CPT is breached and the generator earns compensation. This simple example and the discussion above suggest that generators are more likely to maximise profits by submitting price-quantity offers that keep prices within the CPT but do not necessarily breach it.

3.3.3. Evidence of Generator Bidding Incentives

The (albeit very limited) anecdotal evidence provided by recent high price events in the NEM seems to support this view.[36]

The AER report has noted in the context of the March 2008 price event that *"At the commencement of the heatwave, the cumulative price was $10,300. Over the next three days, the spot price approaches $10,000/MWh on 13 occasions, with the cumulative price reaching $132,000 on 7 March….. for the next four days, despite demand being at or above 2,500 MW, the spot price did not exceed $400/MWh…….On 12 March, 2008, which is seven days into the high priced period, if AGL had continued the bidding behaviour of the previous four days then the cumulative price would have fallen significantly. However, the bidding strategy of AGL on 12 March saw spot prices returning to levels close to $10,000/MWh".*

One might interpret these and other events in that month as reflecting a strategy of the dominant player to monitor the CPT, and trying to stay within it over March 9-12 rather than breaching it, which it probably could given the level of demand.

As noted below, the model design incorporates the incentives and anticipated behaviours just described, including by imposing an explicit CPT constraint on cumulative price outcomes.

35 If all offers are identical, a tie-breaking rule in dispatch engine would prevent such an outcome. However, we assume the offers are close to $1,000 but not necessarily identical.

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

4. MODELLING APPROACH

A conceptual assessment of compensation arrangements allows us to determine the likely risks that the various market participants will face under each of the three compensation arrangements. In this section, we outline the theoretical and empirical modelling framework that is used to confirm the conclusions drawn from our conceptual assessment, and to determine the likely magnitude of risks faced by the various market participants under each of the three compensation arrangements.

At the outset, it is important to note that the model is designed specifically to simulate and predict outcomes that would arise under the various compensation options *in the event of extreme circumstances* – e.g. persistent high demand, very low hydro storage and massive disruption to gas supply throughout the NEM – because, although rare, these are the very types of events which, in combination with other factors such as aggressive generator bidding strategies, are likely to cause an APP.

Moreover, although the objective of this report is to evaluate the merits of alternative compensation mechanisms, it is clear from the preceding discussion that the modelling approach must capture interdependencies between compensation arrangements and other components of the overall risk management package (VoLL, CPT, APC). In addition, it must accurately capture the incentives that market participants face, and how this is likely to impact on the behaviour of market participants. This is especially important in respect of the bidding behaviour of generators when the market is subject to stress conditions, which is when risk management measures will come into play.

4.1. SUMMARY OF MODEL DESIGN

Briefly summarising our modelling approach, our analysis is structured around two recent high price events described below, when the CPT was breached or nearly breached. Demand function parameters have been calibrated using actual demand, price and dispatch data.[37] We have then used a bidding optimisation using a combination of Cournot, Bertrand and PC paradigms. The bidding optimisation allows for generators to rebid during high demand periods. Once the bids are optimised, dispatch is simulated for a range of uncertain demand, energy availability and outage conditions using Monte Carlo simulation. Volatility of spot prices derived from these simulated outcomes is then used to assess the financial risks faced by generators, retailers and MNSP/IRSR holders.

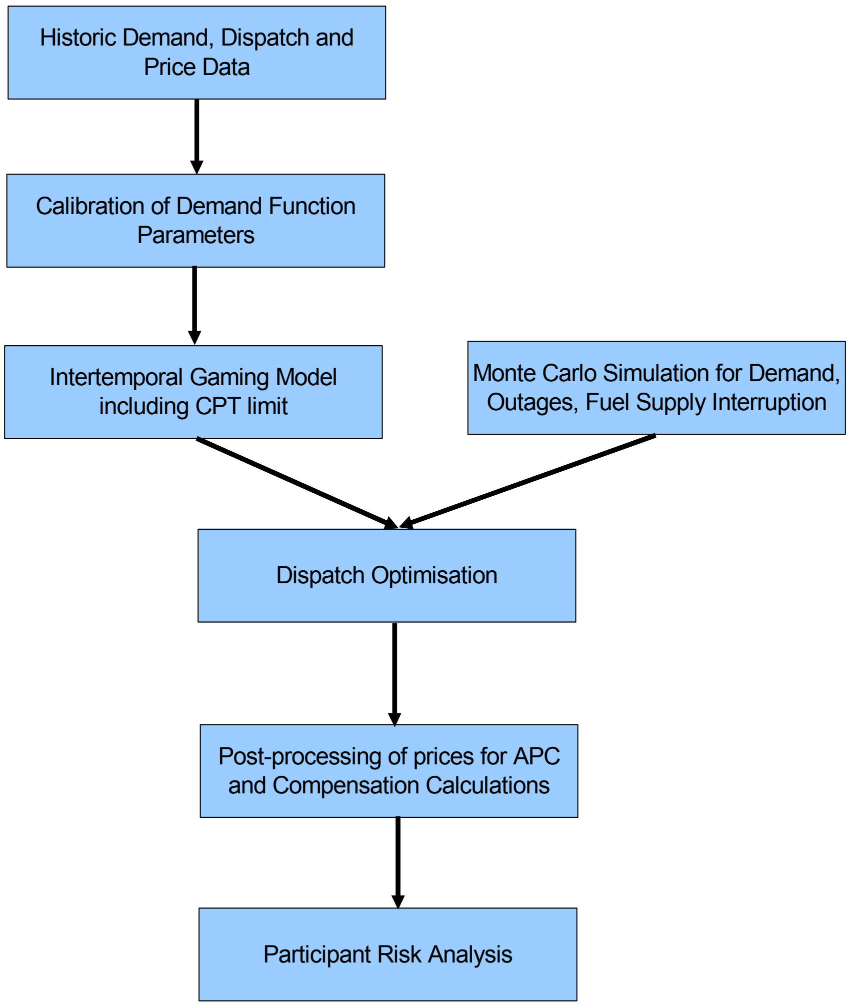
An important aspect of the modelling is that generators explicitly take into account the “CPT limit” as a constraint in preparing their offer volumes and prices. This requires a “look ahead” using expected demand and strategies adopted by other generators. The bidding optimisation model captures these details over a weekly timeframe to derive bids for each

37 We have assumed a probability distribution around the actual demand, i.e., demand varies for each half-hour on either side of the actual demand. Calibration of the demand function refers to deriving a relationship between demand and prices using historical demand and price data. Further discussion on the approach to calibration is included in Appendix B.

half-hourly period of the week. An illustrative example presented above has explained how a binding CPT limit may influence generator behaviour.

Chart 1 summarises the modelling approach we have adopted for the analysis.

Chart 1 **Modelling Process**



Appendix A provides a mathematical description of the bidding model used for the analysis.

As shown in Chart 1, our approach utilises an *intertemporal game-theoretic dispatch model*. This model has the following three attributes:

1. The capability to simulate profit maximising behaviour by NEM generators, taking into account their long term contract and retail positions. We apply a Cournot and Bertrand bidding model together with PC paradigms so that risks and compensation issues may be compared and contrasted;

2. The ability to simulate a variety of random events, including outages of generators, constraints on flows on transmission interconnectors, significant swings in demand, and

fuel supply failures. We have used a Monte Carlo simulation technique that embeds a Cournot/Bertrand/PC dispatch model to simulate these types of events; and

3. The ability to "look ahead" and develop bidding strategies that takes into account the impacts of a sustained VoLL event, including one that may breach the CPT. Specifically, the bidding strategy for each generator incorporates:

    a. An expected demand profile over the next 7 days (336 half-hourly periods);

    b. Potential bidding strategies employed by rival entities;

    c. Transmission constraints;

    d. Energy limits for hydro plants; and

    e. A cumulative price threshold.

Appendices to this report provide further details on our modelling approach, as well as key model input assumptions. In the following sections we elaborate on key features of this model.

4.2. LIMITATIONS OF MODELLING APPROACH

We recognise that our modelling contains limitations, both due to the complexity of the task at hand, as well as given the time constraints for the modelling exercise.

In particular, capturing the multitude of physical drivers that may, in conjunction with generator bidding behaviour, lead to an extreme price event is a difficult task. The difficulty arises both in terms of theoretical modelling as well as in respect of data and computational requirements. There are different theoretical postulates (e.g., whether market power exists or does not exist), alternative sets of assumptions (e.g., whether only demand drives price outcomes or whether other physical factors also drive demand) that may trigger extreme price outcomes. Different approaches to computational implementation (e.g., probabilistic simulation versus deterministic scenarios) may potentially lead to different outcomes. Our modelling estimates should therefore be viewed as indicative.

Given the limited time of less than four weeks available to undertake the analysis described in this report and a primary focus in this report on a conceptual assessment of changes to market design parameters, we have restricted the volume of data and computation to the bare minimum. The focus in this report is therefore on deriving broad insights and indicative estimates of risks for key scenarios, and ensuring the transparency of assumptions and analysis, using two recent high price events, as opposed to a highly detailed analysis of every single five minute period and a large number of scenarios for several months/years.

The analysis described in this report has therefore been limited to a bidding and short term dispatch model using a linear demand function with appropriate calibration of the model parameters.[38] We do not model ancillary service markets and focus on the energy market alone. We have also limited the analysis to two high price events (described in greater detail below): the first occurring in South Australia in March 2008 and the second one occurring in NSW in June 2007.

There is a range of uncertain factors relevant to this modelling, from variation of demand, uncertain hydro inflows, break-down of gas supply and outage of generators. These events are modelled using a simplified probability distribution, in some cases, relying upon very limited information. We have not modelled, for instance, the hydro river chain or gas supply network and uncertainties surrounding each physical element. Instead the impacts of these events on available energy and/or available capacity to a generator are modelled. In forming a view on the relative merits or drawbacks of an option, we have emphasised extreme scenarios such as persistently high demand, very low hydro storage and massive disruption to gas supply throughout the NEM.

Since there is limited information and time available for an exhaustive analysis, we have relied on simplifying assumptions to illustrate the issues, with the objective of informing the discussion on the subject rather than providing a conclusive and accurate view of the levels of compensation for each option. We have endeavoured to make use of publicly available information to the extent available to identify potential extreme scenarios. It is envisaged that substantial amounts of further data and analysis, which are beyond the scope of this study, would be needed to fully assess these risks.

In summary, the modelling approach:

- Relies on short-term modelling only;
- Does not consider frequency control ancillary services (FCAS); and
- Covers only two recent high price events.

The model assumes that price volatility is driven by the combination of generator behaviour and physical drivers such as:

- Demand;
- Hydro energy;
- Generator and interconnector outages; and
- Gas supply interruptions.

Having noted the limitations of our modelling approach, the following sub-section summarises the data used in the modelling exercise.

[38] Although Cournot/Bertrand/PC paradigms are relatively abstract theoretical models, the calibration process ensures that the proposed model yields reasonably realistic outcomes.

4.3. DATA USED FOR MODELLING

Simulation of the high price events in the NEM in recent years focused on two representative weeks, namely:

- March 11-17 in 2008, when SA experienced a series of high price events that led to breaching of the CPT on March 17 around 5:30 pm. Demand and prices for the week used in the model are shown in Chart 2; and

- June 12-18 in 2007, when NSW among other regions experienced very high prices with cumulative prices exceeding $120,000 for the week, although the CPT was not breached. Demand and prices for the week used in the model are shown in Chart 3.

Analysis of these two weeks provides a good basis for understanding the general behaviour of prices and some of their key drivers. As AER analyses show, in both instances, demand was identified as one of the key drivers, but there were other related factors, including generator bidding that exacerbated spot prices.[39]

The AER states that:

1. The SA price event in March 2008 was a relatively localised phenomenon that led to more extreme prices and was primarily caused by a combination of high demand and extreme bidding behaviour by the Torrens Island power station.[40]

2. The high price event in NSW in June 2007, in comparison, was much more widespread. Prices in QLD were also high. Both NSW and QLD price excursions were caused by a combination of high demand and plant unavailability due to water restrictions. The effect of plant unavailability is reflected by the generally higher prices maintained throughout the week in addition to short duration price spikes. Macquarie Generation exhibited extreme bidding behaviour that led to a significant number of the price excursions.[41]

Overall, the events in these two weeks provide a reasonable basis for analysing most of the physical and behavioural drivers.

Chart 2 and Chart 3 graphically depict demand and prices experienced over these two representative weeks, for SA and NSW, respectively.

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39 AER, "Spot prices greater than $5000/MWh, South Australia: 5 - 17 March 2008". May, 2008. AER, "Spot prices greater than $5000/MWh, June 12-28 2007". 2007. Both available at: http://www.aer.gov.au/content/index.phtml/itemId/714860

40 AER 2008, "Spot prices greater than $5000/MWh, South Australia: 5 - 17 March 2008", AER, Melbourne, May, 2008.

41 AER 2007, "Spot prices greater than $5000/MWh, June 12-28 2007", AER, Melbourne, 2007.

Chart 2 South Australian Demand and Prices Used in the Model

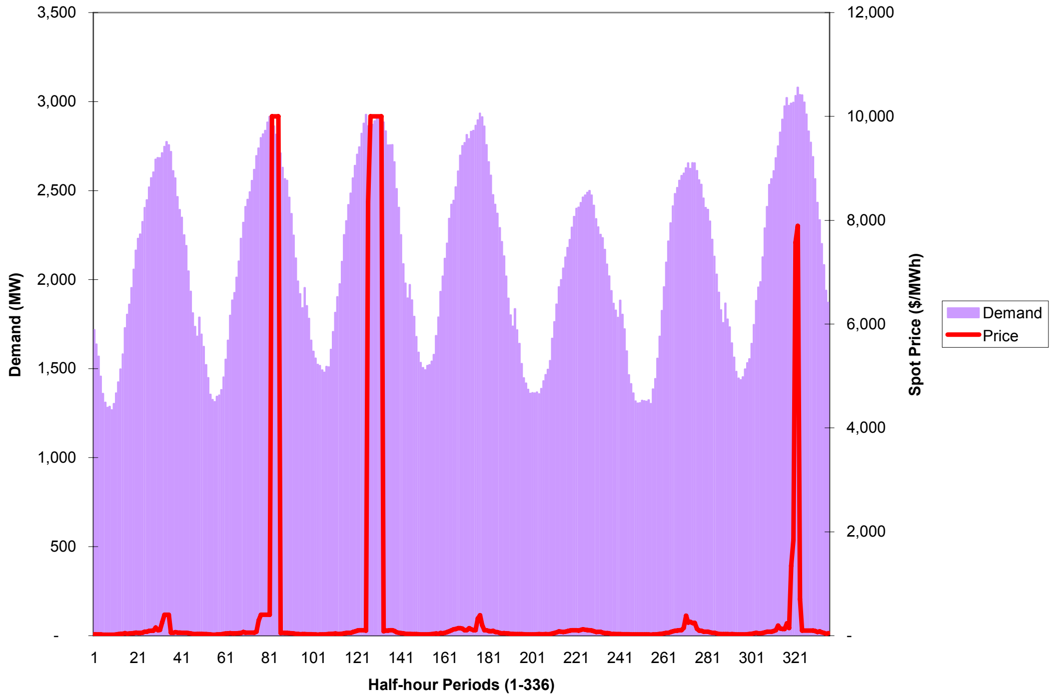
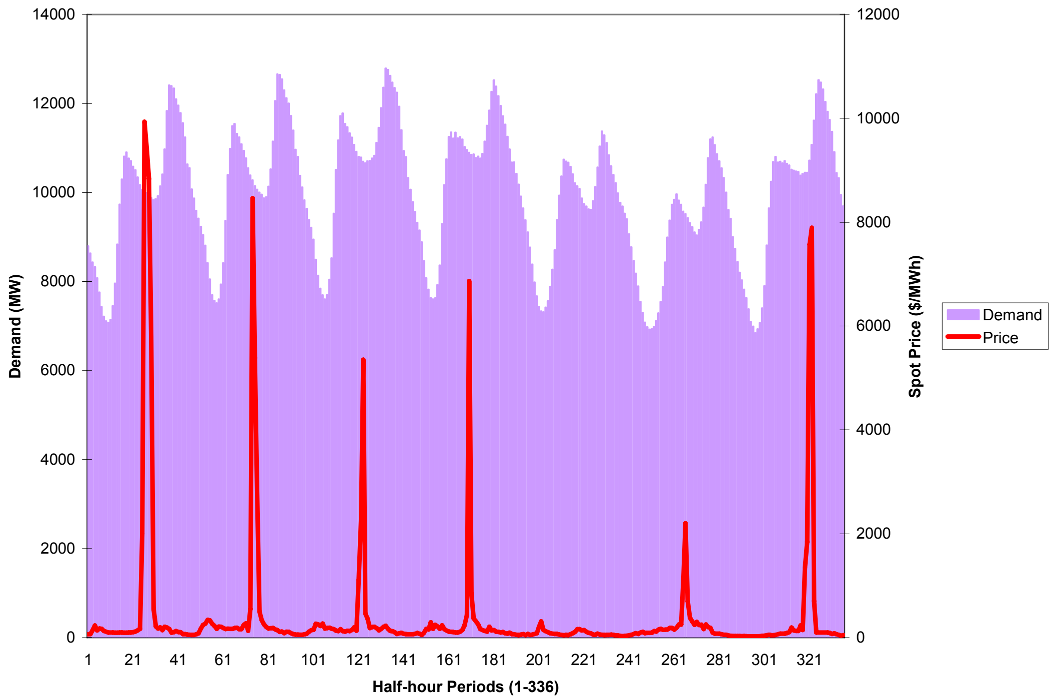


Chart 3 New South Wales Demand and Prices Used in the Model



It is important at the outset to explain why these two weeks were chosen for the analysis, as well as to caveat the interpretation of our modelling results. In particular, the objectives of the simulation exercise we have carried out are to explore potential price outcomes and the nature of volatility in the presence of high demand conditions, and to understand how a combination of outages, demand and energy limits may lead to such extreme price volatility, with the overall aim of determining the optimal compensation mechanism. Our decision to use data from those two weeks in which high price events were experienced reflects our specific focus on extreme price events that may cause financial stress, and trigger compensation arrangements. Modelling results should be interpreted carefully in this specific context, and should not be generalised to a wider context.

5. MODELLING RESULTS

This section summarises the NEM modelling results. We discuss the potential complexities and risks associated with each of the candidate compensation mechanisms. Wherever possible, we illustrate these complexities with examples and simulations. Specifically:

- Sub-section 5.1 demonstrates the potential risks – in terms of market uncertainty and volatility – that an offer based compensation could create, based on the results of simulating an extreme market scenario; and

- Sub-section 5.2 explains how compensation based on opportunity costs may give rise to some of the same uncertainties and volatilities associated with offer based compensation, using illustrative examples.

Further sub-sections consider the specific risks that the alternative compensation arrangements may provide for Network Service Providers (sub-section 5.3), as well as a second-order risk that may arise due to an indirect impact on regional prices caused by price scaling that is applied to avoid negative settlement residues (sub-section 5.4).

5.1. RISKS CREATED BY OFFER BASED COMPENSATION

As noted above, there has only been one CPT breach, for SA in March 2008. No compensation claims were made in relation to this breach. In any case, simulation results for this event show that if the compensation payments were to be based on bids and offers, the value of compensation would be relatively small. For each of the 100 random samples, the total value of offer based compensation was below $20,000 (of which SA generators receive most).

That said, this low compensation is very specific to the SA event of March 2008 where demand fell from nearly 3,000 MW to 1,872 MW over the five hour period immediately following the CPT breach and the two generators bidding aggressively withdrew their high bids following the breach. These simulation results therefore do not fully demonstrate the risks that may transpire if adverse conditions persist following the breach.[42]

In view of this, we have constructed a case around the March 11-17 week but changed the end period demand/price conditions to construct an extreme scenario of offer based compensation. We compare the outcomes of offer based competition with compensation based on direct operating costs. We overlay the following assumptions on the actual event, to effectively perpetuate high price events– and hence compensation payments:

[42] For example, persistent high demand (as in this case) or other disruptive outage events or energy limitations.

- A VoLL of $12,500/MWh and a CPT of $187,500, so that the CPT is less binding for the event;[43]

- Both Heywood and Murraylink continue to operate below their rating;

- No demand side management; and

- Continuation of high demand into the evening and random variation of demand between 2,700 MW and 3,000 MW for 8 half-hourly periods following 5:30 PM.

- APC level of $100/MWh peak and $50/MWh off-peak, which corresponds to the APC level applying at the time of the SA and NSW event. However, as discussed below, if an APC of $300/MWh at all times is assumed, there is no significant change to any of the general conclusions arising from the use of the old APC levels.

As a result, generators continue to bid aggressively, and prices therefore also remain high.

Compensation payments to generators are calculated as follows:

- **Direct cost based compensation:** For all periods following a CPT breach (set at $187,500), if a generator has cleared offers with an offer price higher than the administered price, the compensation amount for the half hour period is:

  $$(DOC - AP) * CGMW$$

  where,

  DOC represents direct operating costs, if it is above the AP

  AP is the administered price, which is either the APC or the scaled APC

  CGMW is the cleared generation MW for which direct operating cost is above the AP

- **Offer price based compensation:** For all periods following a CPT breach (set at $187,500), if a generator has cleared offers with an offer price higher than the administered price, the compensation amount for the half hour period is the sum of all difference payments for all cleared offer tranches:

  $$(OP - AP) * COMW$$

  where,

  OP is the offer price, if it is above AP

[43] These are the higher values of VoLL and CPT that are recommended by the Reliability Panel. AEMC Reliability Panel, *Comprehensive Reliability Review, Final Report*, AEMC, Sydney, December 2007.

COMW is the cleared offer MW with offer prices above AP

A generator is not compensated for cleared generation where direct operating costs, or offer prices, are below the AP.

Simulation results showed significant differences in outcomes depending upon whether compensation was based on direct operating costs or offers, namely:

- On average there is an order of magnitude of difference between the two forms of compensation. Compensation using cleared generator bids averaged approximately $914,000 for the week in SA compared to a direct cost based compensation of $78,000, calculated as an average across the random samples.[44] Offer based compensation payments in extreme cases are close to $2 million and, at the low end, they are close to compensation based on direct costs. The highest amount of compensation based on direct costs is just over $100,000. In other words, retailers face not only a substantially higher compensation payment under offer based compensation, but also one that is extremely volatile;

- Cost based compensation in SA is provided to only three peaking stations that have direct operating costs over $100/MWh, with a combined capacity just over 150 MW. At an average direct operating cost of approximately $300/MWh, the maximum compensation, when they all run at full capacity for the 4 hour period, is 150*(300-100)*4 = $120,000. The actual compensation depends on how much of this capacity is dispatched, and the average compensation is generally lower than this;

- Table 3 provides good insight into why the two forms of compensation differ significantly:

    - Extreme demand, low availability of interconnection and outages allow some of the generators to offer part of the capacity at prices close to VoLL. This capacity depends critically on the level of demand and varies between zero and upwards of 558 MW in an extreme case. Average offer prices vary between $210/MWh to over $5,000/MWh.

    - In contrast, the marginal costs of generation for these periods, calculated using a market simulation that assumes perfect competition (PC), are substantially lower, by a factor of anywhere between 3 and 30.

    - Even if only a small share of the high priced offers is cleared in some of the periods, the compensation payment can add up to several hundred thousand dollars. As the high spot price for the first 5-6 periods indicate, some of the high priced offers did set spot price for these intervals and

[44] Assuming the APC is $100/MWh during peak and $50/MWh during off-peak. As noted above, a VoLL of $12,500/MWh and CPT of $187,500 is adopted to obtain an understanding of the levels of compensation that may be payable under levels of VoLL and CPT that are less binding than those levels that currently prevail. Our analysis of alternative VoLL-CPT level shows SA spot prices on average for the March 11-17 would be 20 per cent higher if VoLL and CPT are increased (Concept Economics, *Risk Assessment of Raising VoLL and CPT*, Draft Report, July, 2008, p.43).

therefore compensation for these generators is much higher than what they would have received based on direct operating costs.

- Importantly, if we assume the current level of APC of $300/MWh, there is no material change to any of the general conclusions above. For instance, the worst case offer based compensation payment for the extreme scenario for SA would be 2.4 per cent lower if an APC of $300/MWh were used. The differences for other cases of offer based compensation are almost negligible. Direct cost based compensation would be reduced to close to zero and therefore the ratio of offer based and cost based compensation would still differ very significantly.

Table 3 **Offer MW at High Prices and Marginal Cost of Generation, based on 100 simulations**

March 17, 2008	Number of Cleared MW with High Offer Price			Avg Offer Price for MW with High Price	Max Offer Price for MW with High Price*	Max Marginal Cost**	Max Uncapped Spot Price
Period	Average MW	Maximum MW	Minimum MW	$/MWh	$/MWh	$/MWh	$/MWh
5:30PM	11	558	0	210	10,501	355	8767
6:00PM	21	557	0	362	9,045	355	6905
6:30PM	50	474	0	1,179	8,421	274	6197
7:00PM	155	862	0	2,954	7,384	355	5429
7:30PM	181	599	0	5,370	7,257	355	5336
8:00PM	79	371	0	4,437	7,924	274	3185
8:30PM	39	325	0	828	3,185	71	72
9:00PM	7	155	0	232	2,901	59	59

Notes:

* VoLL is assumed to be $12,500/MWh for this scenario. ** Maximum marginal cost of generation cost across all random samples of the perfect competition scenario. It represents marginal cost of generation from oil or gas.

5.2. COMPLEXITIES ASSOCIATED WITH OPPORTUNITY COST

Compensation based on opportunity costs, which will add to the direct operating costs, may give rise to some of the same uncertainty and volatility that would arise under offer based compensation.

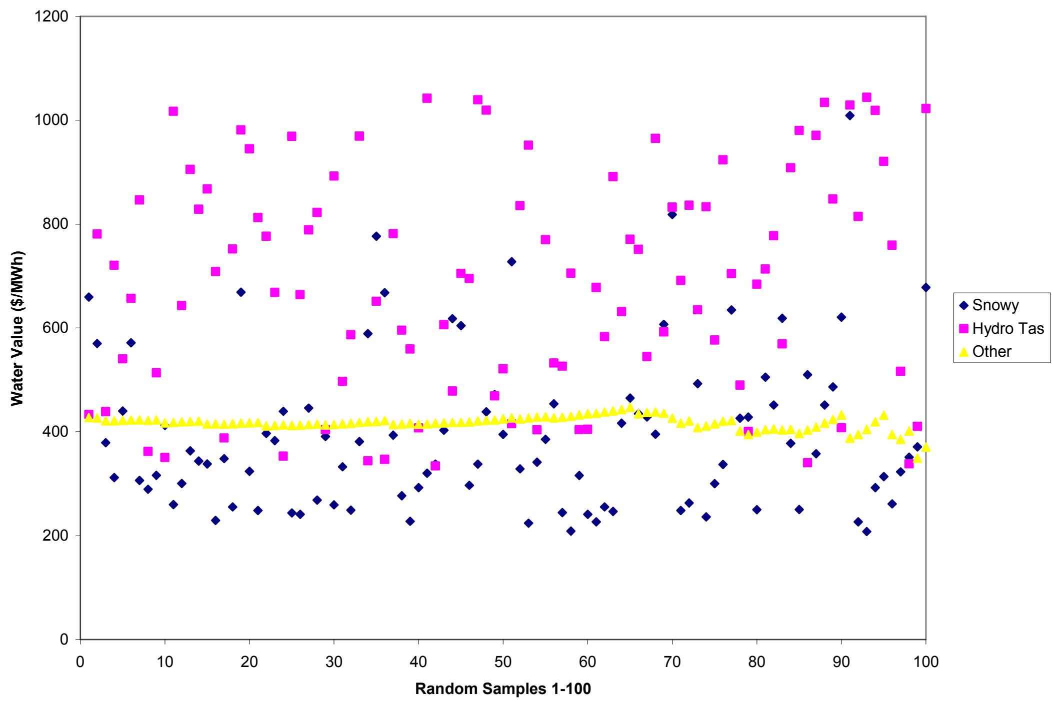
The opportunity cost for storage hydro is probably the most relevant concern, since most of these stations will have low direct operating costs and opportunity cost is a critical component of its cost. This immediately raises the issue of the timeframe over which the opportunity costs should be considered. Depending upon storage capacity, level, inflows, etc., different timeframes may apply for different stations.

In order to illustrate these uncertainties, we have produced water values for three aggregate storage points, including Snowy and Hydro Tasmania, using the June 2007 weekly data and assuming a very low storage i.e. 45 to 60 per cent of the actual inflow or, on average, half of what we have used in our previous simulations (Low Hydrology scenario). We have recalculated water values for the same set of uncertain parameters using our base case assumptions – i.e. 90 to 120 per cent of actual inflows (Medium Hydrology scenario). For the purpose of illustration, we have assumed the water available in a half hour period could be used anytime during the week.[45] Chart 4 and Chart 5 show the scatter plots of water values across the random samples for the two scenarios. There are two key points that are especially worth highlighting, namely:

- Water value or opportunity cost of stored water can vary significantly even before we consider any hydrological uncertainty. Depending on inflows, regional demand, outages, interconnection availability, etc., water value varies across these samples. On average, across all samples and storage points, the opportunity cost for a hydro MWh is $112/MWh which is reflective of the high demand and already low hydro storage situation in June 2007; and

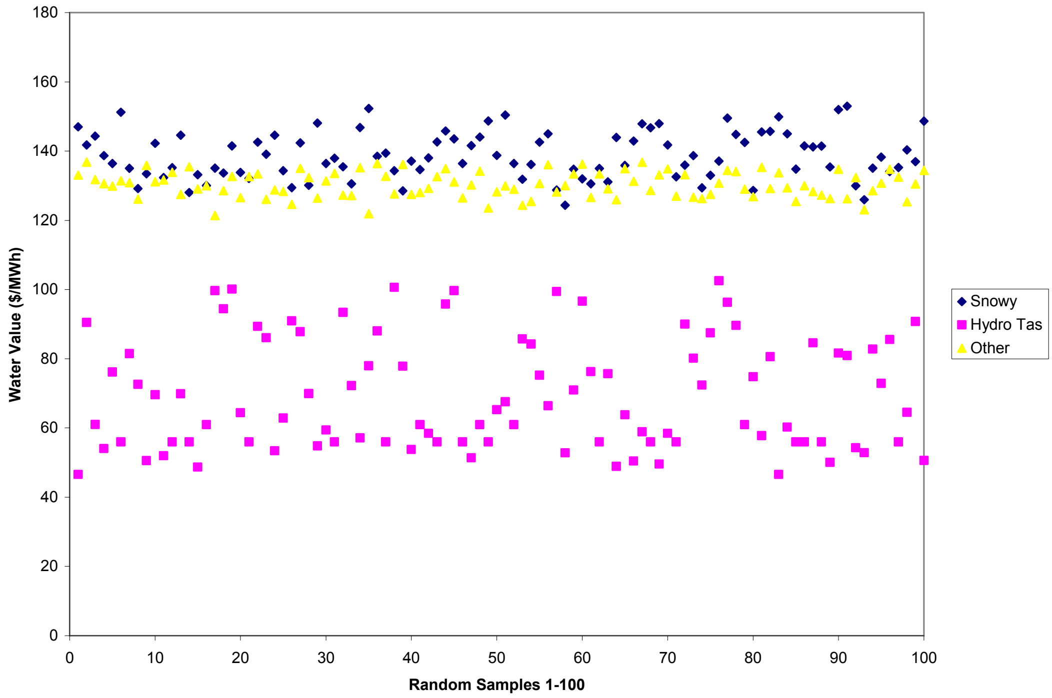
- Hydrological uncertainty around inflows can manifest into a very significant increase in water value because an additional MWh during a dry inflow sequence has a relatively high probability of reducing expected unserved energy in some other period of the month. Hydro opportunity costs average over $500/MWh for the low hydrology scenario.

Chart 4 **Water Value for Major Storage Points for June 2007: Low Hydrology**



45 As noted, the timeframe could be much longer in reality depending upon storage position and capacity.

Chart 5 Water Value for Major Storage Points for June 2007: Medium Hydrology



Although these water value estimates are used merely to illustrate the issues raised under a compensation approach based on opportunity costs, they raise a valid concern over any compensation mechanism that relies on such costs. For example, if NSW happened to breach the CPT during a period of very low hydro storage, hydro generators can effectively have opportunity costs in the order of several hundred dollars per MWh, if not thousands of dollars per MWh, reflecting:

- The value of power generation or demand side resources that it would replace at the time; and
- Expected value of avoided load shed events.

More generally, the opportunity cost and hence SRMC of hydro can vary over the complete range from zero to VoLL. In particular, it may be equal to:

- Zero or near zero in the event that the additional hydro energy would simply go to waste (spilled) if it is not used in the current time period;
- Marginal cost of coal/gas, say between $5/MWh to $40/MWh, if it is replacing a baseload coal or gas MWh;
- Marginal cost of a peaking plant running on gas around $55/MWh to $70/MWh;
- Marginal cost of a peaking plant running on oil around $270/MWh to $355/MWh;

- Marginal cost of any available demand side alternative that has been estimated to be in the range of few hundred dollars per MWh up to $3000/MWh;
- The highest offer price of generation displaced by the dispatch of the hydro MWh; and
- Marginal cost of unserved energy or VoLL.

If hydro generation is being used during the APP, a compensation using opportunity cost may therefore be anywhere in this range, although more likely to be at the higher end of costs during a dry year. This may cause the compensation for hydro stations to be substantial. For instance, if 1,000 MW of hydro capacity is used for 4 hours (i.e., 4 GWh), which has a water value of $1000/MWh, the total compensation payable for the period for this hydro generator alone is: (1000-100)*1000*4, or $3.6 million. This is substantially higher than the total NEM-wide compensation amount we calculated for the extreme scenario in SA. If in fact the water value is even higher, reflecting an avoided VoLL event, the compensation volume may be an order of magnitude higher still or $36 million for a single 1,000 MW generator.

Limited gas supply due to unavailability of gas or a gas supply interruption may also render a high opportunity cost to gas on similar grounds. The probability of a gas infrastructure failure is very low compared to other events that influence the NEM.[46] As such, the probability-weighted impact that we see in the Monte Carlo simulation results is relatively low and the high price events are dominated by other factors such as demand and outages.

In order to develop some insights into the impact of gas generation failures,[47] we have constructed a few extreme scenarios and compared the regional cumulative prices across these scenarios. These scenarios assume that regional gas based generation capacity is unable to operate due to a gas supply interruption, for a range of different outage levels (i.e., in effect assuming *x* per cent of the regional gas based generation capacity is on outage).

We have varied the share of outage from 90 per cent of gas based generation capacity, which represents a catastrophic gas supply disruption throughout the state, down to a relatively minor 10 per cent capacity on outage. Although the share of gas generation in the total NEM generation is still relatively low at around 5 to 7 per cent[48], it is critical for peaking purposes in some regions. Under stressed conditions, such as the winter of 2007, which already had limited hydro generation and restrictions on some coal plants, a gas supply failure could have caused extreme disruptions to electricity supply and lead to highly frequent VoLL prices. Table 4 shows the ratio of uncapped cumulative price under gas supply shortage scenarios and those for the base case for the June 2007 week.

[46] Charles River Associates, *Victorian Gas System Security: Cost Benefit Risk Analysis*, Final Report, March 2002.

[47] This may include failures in the gas supply chain or of the generation plant itself.

[48] On an annual basis using Energy Supply Association of Australia, Gas Electricity Statistic, 2007.

Table 4 **Impact of Gas Capacity Outage on Cumulative Price: June 2007**

	Percentage of Gas Based Generation Capacity Affected in All Regions							
		90%		70%		40%		10%
	Cumulative Price	Ratio*	Cumulative Price	Ratio*	Cumulative Price	Ratio*	Cumulative Price	Ratio*
NSW	521,051	4.34	161,630	1.35	137,071	1.14	129,272	1.08
QLD	180,407	2.48	109,120	1.50	89,576	1.23	83,185	1.14
SA	2,997,954	110.09	212,979	7.82	63,396	2.33	28,895	1.06
VIC	1,201,087	15.91	162,708	2.16	106,210	1.41	84,518	1.12
TAS	1,513,080	56.15	288,696	10.71	87,160	3.23	28,543	1.06

Note: Ratio of uncapped cumulative price in gas supply outage scenario and the base case.

The worst case scenario for the gas supply interruption that causes 90 per cent of the gas generation capacity to be unavailable throughout the NEM, causing prices in SA, which heavily relies on gas generation, to increase as high as $8,900/MWh throughout the week. Other regions are also heavily affected with TAS prices also averaging $4,500/MWh with the cumulative price increasing 56 times. NSW prices that were already high, increase to $1,500/MWh on average for the week.

A 90 percent reduction in the availability of gas-fired generator capacity across the NEM is, as one would expect, characteristic of a catastrophic event. By the same token, a coincident outage on all gas supply capacity is presumably an *extremely* rare event. If we use the Victorian standard, which is 1-in-20 year event, a NEM-wide gas supply failure will probably be even less frequent than that. Nevertheless, this example illustrates that the opportunity cost of gas under such an extreme (rare) event can also rise close to VoLL, since every single GJ available under such circumstances will have an enormously high premium at any point subsequent to an APP.

As a consequence, compensation measures that use opportunity cost can be extremely high. For instance, even if direct generation cost using gas is under $100/MWh, the opportunity cost in SA for gas will be over $8,000/MWh. Although the volume of gas generation is only 10 per cent of a normal week, the compensation amount will be disproportionately high. The APC will be ineffective because the opportunity cost will reflect the gap between uncapped and capped spot price. Wholesale market energy purchasers will therefore also end up paying for the uncapped spot price. If there is no way of hedging such risk against extreme compensation payments, it highlights an extremely rare but high risk event that would cause great financial stress on all retailers and may amount to a systemic market-wide risk.

As more gas becomes available, the extreme price events start disappearing and hence there is a drastic drop in cumulative prices for most regions. SA prices remain high at $633/MWh but the number of VoLL events reduces by a factor of 15. The opportunity cost for gas is still very high and the risk faced by retailers in SA, TAS and VIC is still very significant. However, it highlights how moving from a 90 per cent to a 70 per cent disruption (which is also a severe event) can ease pressure on prices substantially. Opportunity costs for gas therefore also exhibit similar property as that for hydro energy. The other two disruption events, namely, 40 and 10 per cent gas supply outage events, do not breach the

CPT in any region, although regional prices double or treble in SA and TAS in the former case.

Although these simulations are somewhat simplified – for instance, they do not consider the gas supply network, and they assume a uniform reduction in gas based capacity in all regions – these results show opportunity costs for gas based generation can also be:

1. Substantial under extreme gas supply disruptions, to a point that compensation payments can cause extreme financial hardship to retailers; and

2. Volatile, as a comparison of extremely severe and less severe outage scenarios reveals.

In other words, compensation based on opportunity costs may give rise to some of the same uncertainty and volatility that would arise under offer based compensation.

5.3. COMPENSATION ISSUES FOR NETWORK SERVICE PROVIDERS

This sub-section considers the specific risks that the alternative compensation arrangements may provide for Network Service Providers.

Compensation payable to NSPs is a function of the rent collected on an interconnector, calculated using differences between uncapped and capped prices.[49] Exercise of market power by generators for an offer based compensation has an impact for NSPs. Depending upon how localised the high prices are, some NSPs may potentially claim very high compensation.

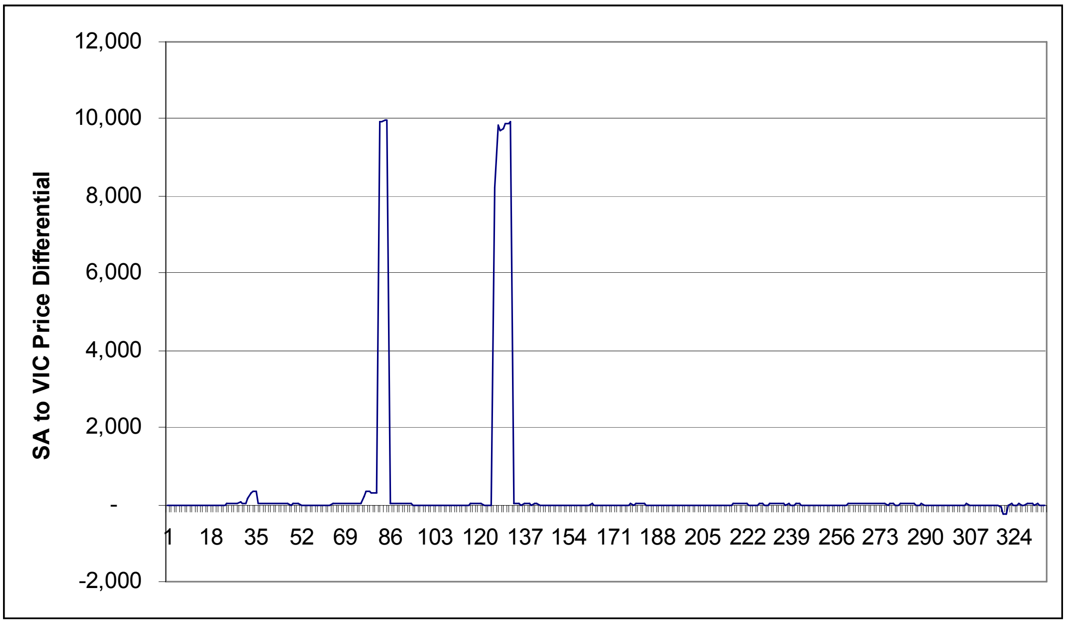
If high prices are relatively concentrated in a single region, such as the March 2008 price event, an application of APC under the current Rule leaves the potential for a high compensation in that particular region. Offsetting this, any high compensation may be confined to this region, rather than spreading across other regions.

As discussed, generators in the region may have an incentive to rebid to raise the uncapped prices that will inflate the difference in rent before and after the price capping. Chart 6 shows the price differential between SA and VIC for March 11-17. Towards the end of the week, just before the breach occurred, VIC prices also increased to a high level, similar to SA prices. Hence, the differential between SA and VIC prices was relatively low. Because of this low price differential, any breach that occurred during these high VIC and SA price periods would have resulted in low compensation payments. Moreover, because VIC and SA prices both fell rapidly following the breach, this would have maintained the low price differential, further minimising the amount of compensation payable. In contrast, SA price spikes earlier in the week were not matched by VIC prices, creating a substantial price differential between VIC and SA prices. As a result, if the CPT had been breached during these periods, compensation payments would have been very high. There were 11 half-hour periods when the differential averaged close to $10,000 and each unit of IRSR could in theory claim this as compensation. However, scaling of prices will not “spread” this impact across other regions,

49 Settlement residue for a regulated interconnector and revenue for a MNSP.

because prices will generally remain low before and after any price capping. The rent difference for other regions will also therefore be low.

Chart 6 **Price Differential Between SA and VIC, March 11-17, 2008**



A price event similar to the one in June 2007 poses a bigger challenge because, in the event the CPT is breached, prices in several regions are affected, broadening the extent to which market participants may be able to claim compensation.

Thus, although compensation for an NSP that connects two high price regions will not necessarily be significant (for reasons that we have just discussed), there were significant price differences between VIC-SA, VIC-TAS, NSW-QLD, etc. for several periods that would have led to high compensation claims in case of a breach. Scaling prices potentially implies that the majority of generators and interconnectors in the NEM will be eligible to claim compensation.

5.4. RISK ISSUES AROUND PRICE SCALING DURING AN APP

Finally, we discuss a second-order risk issue that may arise due to an indirect impact on regional prices due to price scaling that is applied to avoid negative settlement residues. The motivation for this is a recent study by Intelligent Energy Systems (IES), which has raised some of the risk issues that forms the basis of this discussion. [50]

In particular, IES observes that prices are scaled using average inter-regional loss factors for all regions "*as long as they are connected to the region (*that is subjected to APC) *via a sequence of regulated interconnectors*". [51] This leaves the prospect of price capping to

[50] Intelligent Energy Systems, *Regional Settlement Prices During Administered Pricing*, 29 May, 2008.

[51] IES, *ibid*. p.4.

spread across the NEM (with the exception of TAS, for which price scaling is not applicable, as it is connected via an unregulated interconnector).[52] Generators and NSPs are eligible for compensation when prices in a region ("non-APC region") are scaled due to the application of APC in another region ("APC region").

As we have discussed in the preceding sub-section, this is less of an issue if prices in non-APC regions are low. This would be the case if high price events are localised in one region and prices in other regions are insulated by low or binding interconnector constraints. However, if prices in other regions are also high (but not high enough to breach the CPT), the retailers in these non-APC regions face a risk of high compensation payments. Again, as we have discussed, depending on the form of such payment, the degree of risk may vary considerably. For example, an offer-based compensation may pose a more significant risk in the event generators can use market power to maximise the amount of compensation, compared to a direct cost-based compensation.

An alternative approach that IES has raised is not to scale prices for other regions and let negative settlement residues accrue over interconnectors. This helps to confine the regional price risks to the APC region alone. However, retailers in a non-APC region then face either of the following risk outcomes, depending upon whether or not prices are scaled, namely:

- **If prices are scaled**, the spot prices are lowered but the compensation payments can potentially be high. As we have noted, high and volatile compensation amounts present a significant risk because they cannot be hedged using financial contracts that are linked to settlement spot prices (i.e. the Administered Prices during an APP); versus

- **If prices are not scaled**, spot prices will continue to be high, which presents a high spot purchase risk for an unhedged retailer. In addition, there may also be negative settlement residues on interconnectors. Depending upon whether these costs are passed on to retailers and, further, whether retailers are allowed to pass through such costs to customers, this may also present an additional cost risk to retailers.

In addition to the form of compensation payment, the materiality of these risks will depend on the nature of high price events. A shortage of water or multiple coincident outages and/or high demand across the NEM may lead to high prices in several regions. Although one of these regions would approach the CPT ahead of others, the scaling of prices might leave retailers in all other high price regions facing a significant risk of compensation. While there have been no price events in the NEM to date that demonstrates this type of risk, the high price events in June 2007 have characteristics of a widespread high price event. We present below a hypothetical example around the June 2007 to illustrate the impact of price scaling.

Table 5 shows prices for periods 85-88 (or 6:30 PM to 8:30 PM) during June 13, 2007 when prices in most part of the NEM (except TAS where prices had reached price floor) were very high especially in NSW. Let us <u>assume</u> NSW had breached the CPT and that these periods were declared as APPs with prices set to the APC of $100/MWh. Chart 7 shows the net flow directions for these periods. The average interconnector loss factors are used to scale

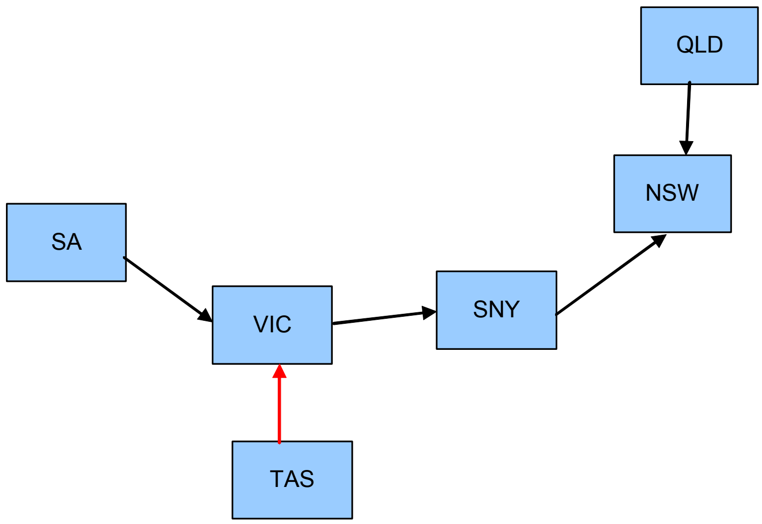
[52] IES, *ibid,* p.10.

prices, resulting in significantly lower prices across all regions except TAS.[53] As the IES report discusses, prices in regions not directly connected (such as SA) will be affected because of the sequence of scaling that applies for flows directing towards the APC region. For example, SA prices in period 88 drops from $434/MWh to $89 because an average loss factor is first applied for flows from SNY→NSW followed by another loss factor from VIC→SNY and finally a third loss factor for SA→VIC.

Table 5 Uncapped and Capped Prices Due to Price Scaling: Illustrative Example

Period	SA	NSW	QLD	SNY	TAS	VIC
			Uncapped Prices			
85	97	9,936	6,951	7,716	- 346	3,929
86	207	9,421	882	7,433	- 1,000	3,456
87	150	8,838	133	7,143	- 1,000	3,297
88	434	5,794	197	4,688	- 1,000	1,999
			Capped Prices			
85	89	100	95	96	- 346	92
86	88	100	95	95	- 1,000	91
87	89	100	95	96	- 1,000	92
88	89	100	95	96	- 1,000	92
			Difference			
85	8	9,836	6,856	7,620	-	3,837
86	119	9,321	786	7,337	-	3,365
87	60	8,738	38	7,047	-	3,205
88	345	5,694	102	4,592	-	1,907

Chart 7 Direction of Flows During Periods 85-88 in June 2007



[53] The TAS price is not scaled because Basslink is a DC interconnector. See IES report, *ibid*, p.10.

The difference between uncapped and capped spot prices for these periods is over \$3000/MWh for VIC, nearly \$2000/MWh for QLD, and over \$7000/MWh for Snowy. Prices in VIC, SA, QLD and Snowy are indirectly administratively capped as a result of price scaling; rather than the APC being directly imposed as result of a CPT breach — as is the case in NSW. That is, if prices were not scaled, retailers in these regions would face substantially higher spot prices. These risks can be managed by a prudent retailer using appropriate contracts.

On the other hand, if an offer-based compensation is used and even a small section of the generators are able raise their offers close to the uncapped price during the APP, the compensation payments – which are essentially reflective of the difference between uncapped and capped prices – faced by VIC and QLD retailers may be substantial. For example, if just 10 per cent of the generators in these regions are to be compensated, total payments for retailers in VIC and QLD are \$4.7 million and \$2.7 million, respectively, over the two hour period. This adds several hundred dollars of unhedged risk for every MWh purchased by every retailer in the region.

5.5. SUMMARY OF COMPENSATION OPTIONS

Our modelling has deliberately focused on extreme scenarios such as persistently high demand, very low hydro storage and massive disruption to gas supply throughout the NEM, given that these are the very situations in which, in combination with other factors such as aggressive generator bidding strategies, an APP and compensation arrangements may be triggered. Obviously, the veracity of the chosen compensation mechanism needs to be tested under such extreme events to avoid a systemic financial risk for purchasers of energy. As we have also stressed, however, the results of our modelling are highly specific to the current context, and are not applicable more broadly to normal market conditions.

The modelling confirms that each of the three compensation arrangements differs in terms of risks each arrangement creates for various market participants. It also enables us to gauge the likely magnitude of risks faced by the various market participants under each of the three compensation arrangements.

Data and time constraints prevent an exhaustive analysis. Instead, we have relied on simplifying assumptions to illustrate the issues, as a means of informing the discussion on the subject. Based on our simulation of an extreme event that extends high demand period for an additional 4 hours on March 17, 2008, we can infer that:

- Offer based compensation may, under such an extreme scenario, yield a compensation payment that is an order of magnitude higher compared to direct cost based compensation; and

- Depending on the nature of uncertainty, both forms of compensation can vary. However, direct cost based compensation has significantly less volatility compared to an offer based counterpart.

This suggests that offer based compensation option can expose retailers to a significant level of risk.

We have also conducted an indicative assessment of opportunity costs for storage water and limited gas availability and demonstrated that an opportunity cost based approach to compensation may give rise to similar risks to offer based compensation. Specifically:

- Opportunity cost for storage hydro may vary a great deal, potentially being equal to:
  - Zero or near zero, in the event the additional hydro energy would simply go waste (i.e., be spilled), if it is not used in the current time period;
  - Marginal cost of baseload coal/gas generation, say below $50/MWh;
  - Marginal cost of a peaking plant running on gas or oil between $50/MWh to $350/MW;
  - Marginal cost of demand side alternatives that may be up to $3,000/MWh; and
  - Marginal cost of unserved energy or VoLL.
- If hydro generation is being used during the APP, a compensation using opportunity cost may therefore be anywhere in this range, although more likely to be at the higher end of costs.
- Similarly, a widespread disruption of gas supply may cause spot prices to be extremely high, especially in regions that rely heavily on gas for peaking duty. Hence, the opportunity cost for the limited volume of available gas may be extremely high. As a consequence, the compensation payment may be very high, rendering the APC package to be ineffective in capping NEM-wide financial risk under such circumstances. Such compensation payments may however hinge critically on the nature of the contingency, namely the size and duration of gas supply interruption. Thus, our experiments suggest that if there is just enough gas available to avoid load shed events, opportunity costs – and hence, compensation amounts – may rapidly decline.

Table 6 summarises the merits and drawbacks of the three compensation options.

Table 6 Comparison of Compensation Options

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 risk 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 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.

We have specifically analysed the implications of compensation arrangements for scheduled network service providers (NSP). Compensation payable to scheduled NSP is a function of the rent collected on an interconnector, calculated using the uncapped and capped price differences. Exercise of market power by generators to induce an offer based compensation has an impact for NSPs. Depending upon how localised the high prices are, some NSPs may potentially claim very high compensation. Specifically:

- If high prices are relatively concentrated in a single region, such as the March 2008 price event, an application of APC under the current Rule leaves the potential for a high compensation in that region. As discussed, generators in the region may have an incentive to rebid to raise the uncapped prices, so as to inflate the difference in rent before and after the price capping. Offsetting this, any high compensation may be confined to this region, rather than spreading to other regions. In particular, scaling of prices will not "spread" this impact to other regions, because prices will generally stay low before and after any price capping. The rent difference for other regions will also therefore be low.

- A price event similar to the one in June 2007 poses a bigger challenge because, in the event the CPT is breached, prices in several regions are affected and scaling prices implies potentially all generators and interconnectors in the NEM are eligible to claim compensation.

With respect to this last point, we have analysed a second-order risk that may arise due to an indirect impact on regional prices caused by price scaling that is applied to avoid negative settlement residues. Scaling of prices in one region, if APC is applied in another region, creates an indirect second-order risk for retailers. Generators and NSPs outside the APC-region are also eligible for compensation payments. Scaling may spread the impact of APC across multiple regions if they are connected through a sequence of regulated interconnectors with flows directed towards the APC-region.

Since this has the impact of spreading the risk of a high and uncertain compensation payment across a wider region, an alternative approach is not to scale prices for other regions and let negative settlement residues accrue over interconnectors. This helps to confine the regional price risks to the APC region alone. However, retailers in a non-APC region then face either of the following risk outcomes, depending upon whether or not prices are scaled:

- **If prices are scaled**, the spot prices are lowered but the compensation payments can potentially be high. As we have noted, potentially high and volatile compensation payments present a significant risk because they cannot be hedged using contracts that are linked to spot prices; whereas

- **If prices are not scaled**, spot prices will continue to be high, which presents a high spot purchase risk for an unhedged retailer. In addition, there may also be negative settlement residues on interconnectors. Depending upon whether these costs are passed on to retailers and, further, whether retailers are allowed to pass through such costs to customers, this may also present an additional cost risk to retailers.

6. CONCLUDING REMARKS

This study has theoretically and empirically modelled three compensation mechanisms, these being based on, respectively:

- Direct costs only;
- Costs that include both direct costs and opportunity costs; and
- Bid/offer based compensation.

The compensation option that uses direct operating costs only is by far the simplest and the most transparent option. However, it is unlikely that this option alone can be relied upon for all types of generators because it does not deal with fixed costs and opportunity costs, which comprise a significant share of costs for some generators. As we have shown by way of illustrative examples, the other two options considered open up significant risk issues for purchasers of energy because these render compensation payments to be both very high and volatile, potentially leading to systemic market-wide failures. Caution is therefore needed before embarking on either one of these two options. In the worst case, a high compensation that is not reflective of costs incurred by generators renders the CPT-APC mechanism ineffective. In particular, we note that:

- Opportunity cost based compensation has a theoretically sound basis, but appropriate data and modelling processes need to be developed and tested to render it an economically efficient and transparent means of compensation; and
- Offer based compensation potentially provides generators with incentives to alter their bids/offers during an APP (i.e., once the CPT breach is known). Appropriate measures need to be in place – which may potentially require changes to the market Rules, so as to limit the extent of rebidding during an APP – in order for this option to be viable.

In summary, the final selection of compensation options needs to recognise that:

- Direct operating cost based compensation is inadequate. Although it offers better transparency, simplicity and certainty relative to the other two options, some consideration of fixed costs and opportunity costs is essential.
- Process and Rules need to be developed/modified for other options. Both opportunity cost and bid/offer based compensation open up significant risk issues from a retailer perspective. Compensation payments can be both very high and volatile for extreme system conditions. Care is therefore required to develop processes and Rules that mitigate such risks.

Finally, although price scaling avoids a negative settlement residue, it potentially exposes retailers all over the NEM to high and uncertain compensation payments that cannot be hedged. If prices across several NEM regions are high, breaching the CPT in one of the regions may result in high compensation payments for all of these regions and therefore constitutes a significant risk to retailers.

APPENDIX A TECHNICAL DESCRIPTION OF THE MODEL

In this appendix, we provide an exposition of the mathematical model used to simulate Cournot, Bertrand and Perfect Competition paradigms in an electricity market. The same general construct applies for each of these three paradigms in the form of a conjectural variation.[54] We first present the Cournot approach, followed by variations around it (Bertrand, Perfect Competition), and then consider their price implications.

The basic premise of the strategic bidding model is that the firms (namely, portfolio generating companies in the NEM) take an individual profit maximizing position by withdrawing production to increase prices above the marginal cost of production. Each firm is sufficiently large to influence market price received by all, and the quantity produced by other firms. Each firm maximizes its own profit given the quantity chosen by other firms expressed as,

$$\pi^i(q_i, q_{i'}) = q_i P(q_i, q_{i'}) - C_i(q_i)$$

where,

$\pi^i(.)$	Profit of firm/player *i* given the production strategy of all other players *i'*
q_i	Production strategy of player *i*
$P(.)$	Price as a function of all *q*'s i.e., firms *i,i'*, etc. This is the key characteristic that distinguishes an oligopolistic market from a perfectly competitive one – i.e. players can influence market price by changing their production, as opposed to the "price taker" behaviour exhibited in a competitive market
$C_i(.)$	Cost as a function of production strategy q_i.

The solution of the game is obtained by solving a set of simultaneous equations representing the first order optimality conditions for each firm *i*. A generalised form of this optimality condition for each player *i* is as follows,

$$\boldsymbol{p} - \boldsymbol{c} + \boldsymbol{q}.\boldsymbol{P'(Q)}\ (1+\boldsymbol{\lambda}) = 0$$

where,

$\boldsymbol{\lambda}$	Conjectural variation parameter $\sum_{n' \neq n} (\partial q_{n'}/\partial q_n)$. If $\boldsymbol{\lambda=0}$, we have a Cournot conjecture in quantity competition and $\boldsymbol{\lambda=(-)1}$ yields a Bertrand conjecture with intense price competition. Prices will strictly increase in the range $\boldsymbol{\lambda \in [-1,0]}$.[55]

[54] Roman Inderst and Tommasso Valletti, *Market Analysis in the Presence of Indirect Constraints and Captive Sales*, Journal of Competition Law and Economics, 3(2), 203-231.

[55] Inderst and Valletti, *ibid*, p.210.

The transmission constrained strategic bidding model is formulated as[56]:

Maximize,

$$\sum_j [\alpha_j - \frac{1}{2}\beta_j Y_j]Y_j - \sum_i q_i C_i - \sum_{i,j} \frac{1}{2}\beta_j X_{i,j}^2 \qquad (1)$$

Subject to,

$$\sum_{(i,j)\in\Omega} X_{i,j} + \sum_{(j',j)\in\Theta} F_{j',j} + \sum_{(j,j')\in\Theta} F_{j,j'} = Y_j$$

(2)

$$q_i = \sum_{j=1}^{M} X_{i,j} \qquad (3)$$

$$\sum_{j=1}^{M} X_{i,j} \le X_i^{\max} \qquad (4)$$

$$F_{j,j'} \le F_{j,j'}^{\max} \qquad (5)$$

$q_i,\ X_{i,j},\ Y_j,\ F_{j,j'} \ge 0$

where,

i,j	Generating company and node indices
Ω	Association of company (generator) and nodes
Θ	Nodal connectivity i.e., connected pairs (*j,j'*)
Y_j	Net injection to node *j* (MW)
q_i	Generation by *i* (MW)
$X_{i,j}$	Generator *i* feeding node *j* (MW)
$F_{j,j'}$	Physical flow from node *j* to node *j'*

56 Additional details on this formulation is available in: D. Chattopadhyay, *Multi-commodity Spatial Cournot Model for Generator Bidding Analysis*, IEEE Transactions on Power Systems, February, 2004.

α_j, β_j	Linear inverse demand equation parameters, i.e., price is defined as, p = α_{j}, - β_j Y_j
C_i	Marginal cost of generator *i* ($/MWh)
$F_{j,j'}^{max}$	Transfer capability (MW)
X_i^{max}	Max generation capacity (MW)

Constraint (2) represents the nodal electricity balance. Equation (3) calculates the total generation from an incumbent company. The physical limits on generation and transmission are expressed in (4) and (5), respectively. Equations (1)-(5) present a single optimisation problem for all the generators. However, as discussed before, the individual generator profit maximisation problems are implicit in this single optimisation. It is equivalent to the dispatch optimisation procedure for an oligopolistic market where generators attempt to withdraw generation to keep prices above marginal cost level. The solution of the non-linear programming problem involves finding the generation dispatch and associated flows across the nodes that maximises the welfare-adjusted total market benefit. This solution automatically ensures that profits of individual generators are maximised, and represents the Cournot-Nash equilibrium outcome.

A.1. ALTERNATIVE PARADIGMS AND PRICING IMPLICATIONS

Equations (1)-(5) can be modified to simulate:

- "Perfect Competition" (PC), by dropping the last term in the objective function, i.e., the maximand (1) reduces to,

$$\sum_j [\alpha_j - \frac{1}{2}\beta_j Y_j] Y_j - \sum_i q_i C_i \text{ ; and}$$

- Bertrand Price Competition (BPC), by:
  - replacing the quantity variables with prices, and
  - using a demand function rather than inverse demand function.

The pricing implications of transmission constraints in a Cournot setup are complex and illustrated around a simple example. We present the pricing analysis for a simple two-node case. Node A and B has one generator each (1 and 2, respectively, with constant marginal costs c_1 and c_2) and we assume the flow direction is from B to A. We use the following notations for the dual problem i.e., the "price" variables associated with the three constraints:

λ^j	nodal prices or the duals of the flow balance (2)

γ^j marginal cost of supply or dual of (3), and

$\pi^{jj'}$ shadow price of transfer capability limit or dual of (5).

Differentiating the Lagrangian with respect to q_i, $X_{i,j}$ and $F_{j,j'}$, we obtain the following pricing relationships:

$\gamma^1 = c1; \gamma^2 = c2$

$-\beta^A X^{1A} + \lambda^A - \gamma^1 = 0$

$-\beta^B X^{2B} + \lambda^B - \gamma^2 = 0$

$\lambda^A - \lambda^B + \pi^{BA} = 0$

The marginal cost of supply in this case reflects the constant marginal cost of supply of the local generator. The nodal prices in a Cournot setting are functions of the demand elasticity adjusted nodal supply, and the shadow price on the flow constraint reflects nodal price differences.

Combining the relevant terms, we get the following relationship between shadow price on flow and production:

$\pi^{BA} = (\gamma^2 - \gamma^1) + (\beta^B X^{2B} - \beta^A X^{1A})$

An important observation is that the constraint on flow has two effects:

- A flow constraint has the impact of creating a nodal price difference equal to difference in nodal marginal cost of supply. This is a well known feature of nodal/locational spot markets including the NEM; and
- The second one is specifically an outcome of a binding transmission constraint in a Cournot gaming context. Since generators can withdraw MW supply and increase price to earn super-competitive profits, the elasticity adjusted production (e.g., $\beta^B X^{2B}$) represents the impact of withdrawal of local generation can have at the local node. The differential elasticity adjusted production is reflected in the shadow price of the constraint. This indicates the extent to which generators can exercise local market power. For instance, the difference in marginal cost between the importing and exporting regions may be partially offset if the local producer in the exporting region exerts strong market power and keeps price in exporting region well above its marginal cost.

A.2. MODELLING INTERTEMPORAL LINKAGES

One of the key issues that the modelling needs to address is the impact of a combined VoLL-CPT package. The modelling framework therefore needs to be extended to determine price and volume outcomes over a number of periods taking into account:

1. Generation capacity availability, i.e., to the extent generator capacity may be in or out of service; and
2. Cumulative price threshold as a constraint on price outcomes, namely if prices over the next *t* periods exceed certain level, prices will revert to an administered price.

Accordingly the gaming model is extended as follows:[57]

Maximize,

$$\sum_t \left(\alpha_t - \frac{1}{2}\beta_t Y_t \right) Y_t - \sum_{i,t} X_{i,t} C_{i,t} - \sum_{i,t} \frac{1}{2} \beta_t X_{i,t}^2 \qquad (6)$$

Subject to,

$$\sum_i X_{i,t} = Y_t \forall t \qquad (7)$$

$$X_{i,t} \le X_{i,t}^{\max} \cdot (1 - \phi_{i,t}) \forall (i,t) \qquad (8)$$

$$\sum_t \phi_{i,t} = 1 \ \ \forall i \qquad (9)$$

$$p_t = \alpha_t - \beta Y_t, p_t \le VoLL, \sum_t p_t \le CPT \perp p_t \ge p^a \forall t \qquad (10)$$

$X_{i,t}$, $\Phi_{i,t}$, $Y_t \ge 0$

where,

t Time period index, $t=1,\ldots,T$ weeks/months

Y_t Total generation supply in t (MW)

[57] This is an extension of the theoretical model: D. Chattopadhyay, *A Game Theoretic Model for Strategic Maintenance and Dispatch Decisions*, IEEE Transactions on Power Systems, Vol 19, No. 4, November, 2004.

$X_{i,t}$ Generator *i* generation in *t* (MW)

$\Phi_{i,t}$ Fraction of generator *i* unavailable capacity in *t*

α_t, β_t Linear demand equation parameters for *t*

$C_{i,t}$ Marginal cost of generator *i* in *t* ($/MWh)[58]

$X_{i,t}^{max}$ Max generation capacity in *t* (MW)

p_t Price in period *t* subject to cumulative price threshold CPT for prices exceeding administered price p_a

The model presented above is a stylized representation of joint generation/capacity and pricing decisions. The model tries to obtain the generation strategy $X_{i,t}$ and associated pricing strategy p_t for all generators that would ensure that these strategies form the CNE. A careful analysis of equations (6)-(10) is critical for understanding the implications of the intertemporal generation and pricing issues. To this end, we analyse the pricing implications as discussed below.

We form the Lagrangian Ψ of the optimization problem and differentiate it with respect to $X_{i,t}$ and capacity $\Phi_{i,t}$ to obtain the following optimality conditions:

$$\frac{\partial \Psi}{\partial X_{i,t}} = \alpha_t - 2\beta_t X_{i,t} - \beta_t \sum_{j \neq i} X_{j,t} - C_{i,t} + \lambda_{i,t} + \mu = 0 \forall (i,t) \qquad (11)$$

$$\frac{\partial \Psi}{\partial \phi_{i,t}} = -\lambda_{i,t} X_{i,t}^{Max} + \theta_i + \mu = 0 \forall i \qquad (12)$$

where,

$\lambda_{i,t}$ duals associated with capacity constraint (8)

θ_i duals associated with intertemporal constraint (9), and

μ dual of CPT limit (10).

[58] The short run marginal cost (SRMC) of generation may vary within a year due to variations in factors such as variable O&M and seasonal heat rates. However, we do not have data on seasonal marginal costs for the NEM and, as such, this has not been modelled.

Optimality condition (11) above presents the well known result of a capacity constrained Cournot Nash problem. $\lambda_{i,t}$ is simply the marginal value of capacity limit and if this limit is not binding, such marginal values reduce to zero. However, the addition of intertemporal pricing decisions implies that generation can now be traded across different time periods to achieve different price outcomes without breaching the CPT. θ_i represents the marginal value of an increment in availability (or, reduction in outage) that is achieved by optimally distributing such available generation *across all periods*. We also note that,

$$\lambda_{i,t} = \theta_i / X_{i,t}^{Max} + \mu \qquad (13)$$

Equation (13) comprehensively represents the intertemporal effect of CPT, namely the shadow price of CPT, the marginal value of generation and the marginal value of capacity across all periods *t* should be equal. Intuitively, this relationship reveals that a binding CPT limit (i.e., positive value of μ) will lead to a price increase that is not necessarily limited to the highest price period but *across all periods*. A more subtle issue to be noted here is that $\lambda_{i,t}$ for generator *i* is also dependent on the generation and capacity withdrawal strategies of other generators ($j \neq i$) as per (11).

APPENDIX B KEY MODELLING ASSUMPTIONS

This section describes the NEM modelling assumptions used in the analysis. The study focuses on two representative weeks in 2007 and 2008 in order to gain a detailed understanding of the factors that played a material role in shaping market events.

B.1. BIDDING SCENARIO ASSUMPTIONS

A combination of Cournot, Bertrand and perfect competition bidding was used for the analysis to gain insights about the role that generator behaviour plays in setting prices, and also to assess alternative compensation arrangements.

Price Elasticity of Demand

A key input parameter that determines bids is the elasticity of demand, for which we have relied on NIEIR's average regional estimate of elasticity (as shown in Table B1). These elasticity values determine the extent to which high spot prices can be mitigated by demand-side responses.

Table B1 Price Elasticity of Demand

	Elasticity
QLD	0.29
NSW	0.37
VIC	0.38
SA	0.32
TAS	0.23

Source: National Institute of Economic and Industry Research, *The own price elasticity of demand for electricity in NEM regions*, Report submitted to NEMMCO, June 2007.

Contract Levels

Contractual obligations, especially two-way hedges held between generators and retailers, form another critical input to generator bids. Contracts significantly limit the exposure to spot price volatility for both generators and retailers. There is little information available in the public domain pertaining to generator specific contract levels. As such, we have relied on a calibration procedure to determine contract levels for different time periods (namely, super-peak, peak, off-peak) that reasonably reproduce actual bidding and price behaviour. In other words, we have used observed bidding patterns and pricing outcomes in the NEM in order to deduce levels of contract cover for broad classes of generators across the NEM regions. These contract covers vary across regions depending on the concentration and demand pattern and, on average, are found to be in the range of 75 to 85 per cent across all generator types. These figures generally align with those reported in some of the other studies including the IES study (2004), Anderson and Hu (2006) and ACCC (2000).[59]

Demand Functions

A linear demand curve has been derived for each region for half-hour periods of the week. Calculation of intercept and slope terms of these demand curves takes into account actual demand and prices. In order to calibrate the demand function, we assume the actual demand/price pair is one of the points on the demand curve. The slope and intercept terms are estimated using a regression of demand and price. The elasticity of demand forms an input to the calibration to calculate the expected slope (given an intercept).

Bertrand and Cournot models use different forms of demand curve, but both essentially model demand as a function of price. Each generator maximises its profit assuming a downward sloping demand curve and adjusts either generation quantity (under a Cournot framework) or bid price (under a Bertrand framework) to achieve an equilibrium profit maximising solution. The derivation of demand parameters and the choice of Cournot and Bertrand paradigms are well documented in the academic literature.[60]

Generator Operators Costs

Finally, generator direct operating costs are obtained from the latest ACIL Tasman report prepared for the NEMMCO and presented along with other generator data in Table B3.

Transmission

Base interconnector capacity data and average loss factors are shown in Table B2. The transmission capacity and actual loss factors across the half-hour periods vary depending on the available transmission capacity and dynamic loss factor equations used in the model.

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59 Intelligent Energy Systems, *Regional Boundary and Nodal Pricing*, December 2004.

E. Anderson and X. Hu, *Forward Contracts in Electricity Markets: The Australian Experience*, Centre for Energy and Environment Studies, May 2006.

ACCC, *VoLL Capacity Mechanisms and Price Floor*, December 2000.

60 See for example, James Bushnell, *Oligopoly Equilibria in Electricity* Markets, Centre for Study of Energy *Markets,* CSEM WP 148-R, October 2006. for a discussion on Cournot model. An example of a price competition model is presented in: *Richard* Green, *Did English Generators Play Cournot? Capacity withholding in the electricity pool"* Cambridge Working Paper, CWPE 0425, 2004.

Table B2 Base Transmission Capacity and Average Loss Factors

Interconnector	From	To	Max Forward Capacity (MW)	Max Reverse Capacity (MW)	Average Dynamic Loss Factor
BassLink	TAS	VIC	630	480	7.0%
N_Q_MNSP1	NSW	QLD	180	195	5.0%
NSW1_QLD1	NSW	QLD	621	1078	4.6%
SNOWY1	SNY	NSW	3465	1150	4.1%
V_S_MNSP1	VIC	SA	220	135	3.5%
V_SA	VIC	SA	460	300	2.6%
V_SN	VIC	SNY	1235	1863	4.4%

B.2. APPROACH TO MONTE CARLO SIMULATIONS

Uncertainties in the following parameters have been used as part of Monte Carlo simulation studies:

- Generator forced outage rates, as shown in Table B3, are used to model individual generating unit full outages;
- Peak period demand forecast errors (12 hours ahead) up to 5 per cent on either side of the actual demand are simulated;[61]
- Hydro energy limits are restricted to within a band of -10 per cent and + 20 per cent of the actual dispatch based on the available long term generation potential data;[62]
- Interconnector outage rates are typically much lower than those for generators. They have generally been excluded for NEM simulation studies including the ANTS. However, given the potentially large impact they may have on spot prices, they have been modelled as a low probability event in the range of 0.1-0.2 per cent;[63]
- Gas curtailment has been modelled as 1-in-20 year events as noted in VENCORP planning documents and used for modelling simulations.[64]

61 Actual demand forecast errors for the two weeks varied and were both higher and lower than 5 per cent, e.g., NSW demand forecast errors were up to 7 per cent on one occasion in June 2007. An average symmetric error of 5 per cent is generally representative of the forecast errors. The Mean Absolute Percentage Error (MAPE) performance of NEMMCO's load forecasting tool has been reported to have a much better accuracy (below 1 per cent) but this has been derived using testing over a wider timeframe and presumably for less volatile demand conditions.

62 Based on a number of sources, including: the long term average capacity factor presented in, NSW Greenhouse Benchmarks Position Paper, Ministry of Energy and Utilities, December 2001; Individual hydro station outputs over 1999-2008 (April); and the Hydro Tasmania storage level.

63 There is limited available information on history of partial/full outage rates applicable for the Australian information. Transgrid has reported an outage rate of 8 hours per 170 km-year for 330 kV lines which is approximately an outage rate of 0.1 per cent and Hydro Tasmania has reported Basslink availability (including planned outages) is reported to be 99.7 per cent.

64 VENCorp, *Major System Augmentation Report for the Victorian Principal Transmission System*, November, 2005.

B.3. GENERATOR DATA

Table B3 lists the data on NEM power stations used in the modelling study.

Table B3 Generator Data

	Region	Intra-Regional Loss Factor	Capacity (MW)	Auxiliary Consumption (%)	Forced Outage Rate (%)	Planned Outage Rate (%)	Direct Operating Cost *($/MWh)
Barcaldine	1	0.9473	49	3%	5%	8%	48.29
Barron Gorge	1	1.0695	60	0%	4%	5%	-
Braemar	1	0.9629	450	3%	10%	2%	24.17
Callide A	1	0.9085	-	7%	4%	4%	-
Callide B	1	0.9115	700	7%	4%	4%	13.69
Callide C (CPP)	1	0.9097	920	7%	4%	4%	12.76
Collinsville	1	1.0253	187	9%	4%	4%	21.60
Gladstone	1	0.9428	1,680	5%	4%	4%	15.45
Kareeya	1	1.0808	88	0%	4%	5%	-
Kogan Creek	1	0.9629	763	8%	4%	4%	5.92
Mackay GT	1	0.9562	34	3%	10%	2%	330.04
Millmerran	1	0.9725	860	8%	4%	4%	6.07
Mt Stuart	1	1.0367	294	3%	10%	2%	273.32
Oakey	1	0.9483	320	3%	10%	2%	52.15
QLD Wind Projects	1	0.9749	12	0%	2%	5%	
Roma GT	1	0.9582	68	3%	10%	2%	57.47
Stanwell	1	0.9320	1,440	7%	4%	4%	13.63
Swanbank B	1	0.9943	480	8%	4%	4%	20.04
Swanbank E	1	0.9935	370	3%	5%	8%	16.00
Tarong	1	0.9663	1,400	8%	4%	4%	11.85
TNPS1	1	0.9661	443	8%	4%	4%	11.05
Wivenhoe	1	0.9890	500	0%	4%	5%	-
Yabulu	1	1.0131	243	3%	10%	2%	-
Bayswater	2	0.9383	2,760	6%	4%	8%	12.32
Blowering	2	0.9815	80	0%	4%	0%	-
Eraring	2	0.9842	2,640	7%	4%	8%	16.88
Hume (NSW)	2	1.0057	-	0%	4%	0%	-
HVGTS	2	0.9406	51	3%	10%	1%	309.15
Liddell	2	0.9387	2,100	5%	4%	8%	13.02
Mt Piper	2	0.9641	1,400	5%	4%	8%	17.12
Munmorah	2	0.9883	600	2%	4%	8%	18.31
NSW Wind Projects	2	0.9752	17	0%	2%	5%	-
Redbank	2	0.9265	150	8%	4%	8%	12.74
Shoalhaven	2	1.0183	240	0%	4%	0%	-
Smithfield	2	1.0023	160	5%	2%	7%	37.40
Vales Point	2	0.9861	1,320	5%	4%	8%	16.08
Wallerawang	2	0.9643	1,000	7%	4%	8%	19.03
Guthega	6	0.9680	60	0%	4%	4%	-
Murray	6	1.0000	1,500	0%	4%	4%	-
Tumut3	6	1.0009	1,500	0%	4%	4%	-
Upptumut	6	0.9958	616	0%	4%	4%	-
Somerton	4	1.0000	160	3%	10%	1%	45.07

	Region	Intra-Regional Loss Factor	Capacity (MW)	Auxiliary Consumption (%)	Forced Outage Rate (%)	Planned Outage Rate (%)	Direct Operating Cost *($/MWh)
Anglesea	4	1.0173	154	10%	4%	5%	6.06
Bairnsdale	4	0.9691	90	3%	10%	1%	39.84
Dartmouth	4	0.9619	154	0%	4%	4%	-
Eildon	4	0.9934	120	0%	4%	4%	-
Hazelwood	4	0.9673	1,600	10%	4%	5%	2.32
Hume (VIC)	4	1.0000	29	0%	4%	4%	-
Jeeralang A	4	0.9638	232	3%	10%	1%	47.77
Jeeralang B	4	0.9638	255	3%	10%	1%	47.77
Laverton North	4	0.9954	340	3%	10%	1%	50.79
LoyYang A	4	0.9699	2,190	8%	4%	5%	2.12
LoyYang B	4	0.9699	1,032	8%	4%	5%	5.87
McKay	4	0.9738	150	0%	4%	4%	-
Morwell	4	0.9676	148	15%	4%	5%	-
Newport	4	0.9957	510	5%	2%	7%	43.63
Valley Power	4	0.9699	336	3%	10%	1%	54.24
VIC Wind Projects	4	0.9801	134	0%	2%	5%	-
West Kiewa	4	0.9911	72	0%	4%	4%	-
Yallourn	4	0.9529	1,487	9%	4%	5%	2.38
Hallett	3	0.9802	188	3%	10%	1%	58.88
Angaston	3	1.0011	40	8%	10%	1%	273.86
Dry Creek	3	1.0012	140	3%	10%	1%	71.58
Ladbroke	3	0.9589	84	3%	10%	1%	32.76
Mintaro	3	0.9737	88	3%	10%	1%	65.51
Northern	3	0.9706	540	5%	4%	8%	17.71
Osborne	3	0.9998	190	5%	2%	4%	33.32
Playford B	3	0.9710	240	8%	4%	8%	25.55
Port Lincoln	3	1.0226	50	8%	10%	1%	355.30
Pelican Point	3	0.9989	474	2%	5%	4%	32.23
Quarantine	3	0.9959	92	2%	10%	1%	47.74
SA Wind Projects	3	0.9883	388	0%	2%	5%	-
Snuggery	3	0.9636	63	3%	10%	1%	355.50
Torrens A	3	0.9994	504	5%	2%	4%	50.40
Torrens B	3	0.9994	824	5%	2%	4%	46.37
Bell Bay	5	0.9985	228	5%	2%	4%	55.96
Bell Bay Three	5	0.9976	108	3%	10%	1%	60.97
Tasmania Hydro	5	0.9777	2,281	0%	4%	5%	-
Tasmania Wind Projects	5	0.9913	142	0%	2%	5%	-

Notes: *ACIL Tasman estimates of Short Run Marginal Costs that include direct operating costs including fuel and O&M costs. ACIL Tasman, *Fuel Resource, New Entry and Generation Costs in the NEM*, Final Report, September 2007.