30 June 2006

The Reliability Panel
Australian Energy Market Commission
PO Box H166
AUSTRALIA SQUARE NSW 1215

By email: panel@aemc.gov.au

AEMC Reliability Panel: Comprehensive Reliability Review

The Energy Retailers Association of Australia (ERAA) welcomes the opportunity to provide a submission in response to the AEMC Reliability Panel's paper *"Comprehensive Reliability Review: Issues Paper"*. The ERAA is an independent association representing ten retailers of electricity and gas throughout the National Electricity Market (NEM) and the National Gas Markets. ERAA members collectively provide electricity to over 98% of customers in the NEM and are the first point of contact for end use customers for both Gas and Electricity.

The ERAA believes reliability of bulk supply in the NEM since its inception has been acceptable. Significant investment in generation and interconnection has been undertaken over this period to satisfy rising demand. The ERAA is of the view this investment has been largely efficient and timely.

Retailers also contribute to managing reliability through Demand Side Response (DSR) arrangements to reduce peak demand. Realising the full benefits of DSR in the NEM is currently frustrated by regulated retail price caps. The ERAA supports the removal of retail price caps to allow further DSR to be pursued through innovative price structures. The ERAA believes NEM participants are appropriately incentivised to manage reliability without inefficient intervention by NEMMCO.

The ERAA supports current initiatives being undertaken to efficiently manage network congestion and to achieve a truly national approach to the development of the network. The ERAA supports in particular current work being undertaken to improve incentives for transmission companies to operate the transmission system in a more efficient manner. We consider these initiatives will do much to address any reliability concerns in the NEM with the current market design more than capable of encouraging sufficient future supply in our view.

Below are responses to the questions raised in the Issues Paper that are most important to the ERAA.

Overarching Questions (Questions 1-9)

Demand has been increasing strongly in all regions since commencement of the NEM yet sufficient investment in generation and transmission, as well as DSR, has occurred to meet this demand. With the exception of the period of industrial action in Victoria in year 2000 (which the ERAA believes should be ignored for the purposes of considering reliability), the reliability standard has been satisfied in all regions of the NEM in all years since market start. This is further reflected by the fact that reserves acquired under reserve trader provisions to date have not been required, which strongly supports the notion that the current market design and its price setting are appropriate.

It is important to note in this context that the overwhelming majority of supply interruptions to end-use customers are distribution related. To give an indication of these relativities, in southeast QLD, transmission and generation interruptions accounted for 6% of total interruptions to end-user supply in 2004/05 and just 1% in 2003/04[1]. For the rest of Queensland, transmission and generation interruptions accounted for 4% of total interruptions to end-user supply in 2004/05 and 3% in 2003/04[1]. The ERAA is hopeful that the AER in its new role regulating distribution revenue will provide appropriate incentives for distributors to continue to improve the efficient operation of their networks.

It is the ERAA's opinion that further demand growth in the short-to-mid term will be satisfied by new generation projects currently under construction as well as generation and interconnection projects in the advanced stages of planning. We also consider there to be strong prospects for the increased penetration and utilisation of DSR. When combined with current initiatives to improve constraint management and transmission investment, future investment brought about through the current market design will be more than sufficient to ensure future reliability standards will be met.

Question 9 – Scenarios in Appendix 2

The ERAA engaged Network Advisory Services (NAS) to review the mechanisms used by other electricity markets to signal the need for investment to meet reliability standards. NAS reviewed five electricity markets including Western Australia, New England, Great Britain, Nord Pool, and Chile. NAS concluded that none of the mechanisms employed in those markets are more effective than the mechanisms currently employed in the NEM to signal investment. NAS's final report, *"Literature Review – International Market Mechanisms"*, is attached to this submission.

The scenarios outlined in Appendix 2 have largely been tested overseas and found to be no more effective than current NEM arrangements (see NAS report). The ERAA does not support further development of any of the scenarios in Appendix 2.

Reliability Standard (Questions 10 – 24)

Question 10 – Reliability standard measure

The reliability standard should be a direct measure of the impact of reliability on customers. An end-user's primary interest in energy is continuity of supply and they will judge and value the service on this basis. The ERAA supports the current

[1] Queensland Competition Authority service quality performance reports – http://www.qca.org.au/electricity/service-quality/reports.php

reliability standard measure of unserved energy, which is a direct measure of the impact of reliability on end-users and is superior to deterministic measures that fail to consider customer input.

Question 13 – NEM-wide reliability standard

The ERAA supports the principle of a national electricity market where market participants can efficiently operate in multiple jurisdictions. All regulatory decisions should where possible promote the national character of the NEM. The ERAA sees little benefit in defining different reliability standards for each region and supports a common NEM-wide reliability standard applying consistently across all NEM regions. Additionally from an operational perspective, different reliability targets in each region would require different levels of VoLL to achieve those targets. This would be impractical.

Question 14 – Level of the NEM reliability standard

The reliability of supply should be considered in the context of the entire electricity supply chain. Shortfalls in the bulk supply system account for only a small fraction of supply interruptions experienced by end-users, with the distribution system making a far greater contribution. Thus increases in reliability of the "bulk supply system" are unlikely to make a significant impact to the reliability of supply to end-users. End-users may however notice an increase in energy costs required to fund the highly under-utilised generators built to satisfy an excessive reliability standard.

The ERAA notes recent initiatives to improve the operation of distribution networks and considers this should be the key focus for addressing reliability concerns.

However, the ERAA believes the reliability standard should be maintained at its current level.

Question 16 – Should the reliability standard be a cap or a standard

A cap implies that the limit must not be exceeded at any cost. A reliability standard treated as a cap would require inefficient levels of investment to ensure compliance. The ERAA supports treating the reliability standard as a target that promotes economic investment but allows excursions beyond the target as a result of extreme events.

Question 17 – Should the reliability standard be defined over a period of time

The reliability standard should be defined as an average over 10 years. The ERAA is of the view that the NEM bulk supply system will satisfy the reliability standard comfortably most years. However it would be uneconomic to plan the bulk supply system to meet a 1 in 10 year extreme event. Such an extreme event could cause the reliability standard to be breached if averaged over a shorter period such as one year and would signal the need to invest in infrastructure that would lay idle for lengthy periods at significant cost to end-users. The ERAA is of the view that the cost of investment to build sufficient reserves to meet a 1 in 10 year event exceeds the value of customer reliability.

Question 18 – Triggers for reviewing the Reliability Standard

The NEM has been in a constant state of review since its inception. While aspects of the NEM design have clearly benefited from improvement, constant change or consideration of change creates regulatory fatigue, uncertainty and increased business risk.

The ERAA supports reform where reform is clearly justified and accompanied by appropriate lead time to minimise regulatory risk. The ERAA is of the view that the current level of the reliability standard and market design to achieve that standard is appropriate and does not believe there is a case to review these again in the near term.

Question 22 – Extending the reliability standard to encompass multiple contingency events

As reliability standards are associated with having sufficient underlying supply to meet demand, the standard should only measure those events where additional underlying supply would have resolved or reduced the deficiency contributing to the standard not being met.

Transient and system security issues should be clearly defined as external to the measure as they are operational matters and should not be addressed through the reliability standard. Whilst these types of contingencies may be mitigated by having more plant operating they could not be resolved by simply having more plant installed.

Take, for example, the widespread interruptions in NE US and Italy in 2003. Both of these were caused by contingencies beyond the normal operating standards, yet they occurred at a time when there was adequate reliability reserve in the form of standby generation. It was not running because that type of contingency was not foreseen as credible and therefore the technical envelope was too narrow to prevent them. If system security related load shedding events were deemed to require a response, it would be by narrowing the technical envelope rather than increasing reserve standards. If this were seen to be necessary (not an ERAA view) it would be achieved through measures such as lowering transmission capacities (e.g. operating to N-2) or increasing ancillary services procurement.

It is important to separate statistics on load shed from this kind of system security incident from that shed by a shortfall in capacity, as the appropriate response is quite different.

Question 24 – Inclusion of 'exogenous' matters in the reliability standard

The ERAA does not support the inclusion of exogenous matters in the reliability standard. Failure to meet a reliability standard incorporating exogenous matters would signal the need to invest in the bulk supply system. The ERAA would consider investing to manage large losses of generation during events such as industrial action to be impractical and inefficient.

Energy Retailers Association of Australia, ABN 24 103 742 605.
Suite 2104 Level 21, Tower 1, 520 Oxford St, Bondi Junction NSW 2022
Tel: 02 9369 3263 Fax: 02 9369 306 Email: secretariat@eraa.com.au Web: www.eraa.com.au

Price Mechanisms (Questions 25-37)

Question 25 – Do current price mechanisms encourage appropriate investment?

Since NEM commencement, demand has grown in all NEM regions. Over this same period significant investment has occurred in generation and transmission (including interconnection) to meet the additional demands on the system. With the exception of the period of industrial action in Victoria in year 2000, the reliability standard has been met in all NEM regions in all years since NEM commencement.

It is the ERAA's opinion that investment has been efficient, with an appropriate mix of peaking and base load in the right regions, and has been timely. The ERAA does not consider there to be a need to introduce additional mechanisms to deliver capacity in the NEM.

Question 28 – Tools for limiting exposure to extreme price outcomes.

<u>VoLL</u>

The ERAA supports maintaining VoLL as a cap on the spot price. The ERAA recognises the importance of setting the value of VoLL to achieve an appropriate balance between allowing generators to earn a fair return on investment, promoting liquid financial markets, and limiting exposure of all market participants to high spot prices.

The ERAA is of the view that the current level of VoLL achieves an optimal balance between these factors. Investment in new generation has been forthcoming and timely indicating appropriate financial incentive to invest. Since VoLL was increased to $10,000, there has been relatively few dispatch intervals in which the spot price has reached VoLL. This suggests that any increase in VoLL would have little impact on investment returns as there are few instances where the spot price may have risen above $10,000. However risk to participants would increase encouraging retailers to seek additional contracts and generators to seek less.

<u>Cumulative Price Threshold ("CPT")</u>

During an administered price period, generators are eligible for compensation if their costs exceed the administered price cap. Retailers that are hedged above the administered price cap do not receive the benefit of that hedge, while they are required to pay their share of the compensation to generators. This creates an unhedgeable risk for retailers.

The ERAA engaged Creative Energy in January 2004 to review the administered price setting mechanism in the NEM. The ERAA supports Creative Energy's findings in relation to the administered price setting mechanism, and would encourage the Reliability Panel to consider these findings as part of the Comprehensive Reliability Review. Creative Energy's final report, *"Investigation into the Administered Price Capping Mechanism – January 2004"*, is attached to this submission.

The ERAA also supports consideration being given to physical triggers for administered price setting.

Energy Retailers Association of Australia, ABN 24 103 742 605.
Suite 2104 Level 21, Tower 1, 520 Oxford St, Bondi Junction NSW 2022
Tel: 02 9369 3263 Fax: 02 9369 306 Email: secretariat@eraa.com.au Web: www.eraa.com.au

Question 31 – Forward Market Mechanisms

The ERAA does not support mandating forward trading mechanisms. Forward trading through over the counter bilateral contacts in the NEM is currently efficient. Some exchange based forward trading mechanisms have been established in the NEM to meet demand for standardised products. The ERAA recognises the benefits of such arrangements and is of the view that new products and mechanisms will be provided when economic to do so and demanded by the market.

In fact Sydney Futures Exchange (SFE) trading volumes have increased significantly over recent years.

Table 1 – Performance Summary d-cyphaTrade[2] - Source: d-cyphaTrade

Performance Summary

d-cyphaTrade

	Yr Ending Feb 2005	Yr Ending Feb 2006
Total Contracts	11,528	22,846 (+98%)
Average Daily Volume	45	90
% of physical energy	11%	22%
Total MWh (Approx)	20.7 million	42 million
Face Value (Approx)	$870 million	$1.764 billion
Open Interest (COB 31/12)	8,833	16,963 (+92%)
Open Interest in MWh	16 million	30.2 million

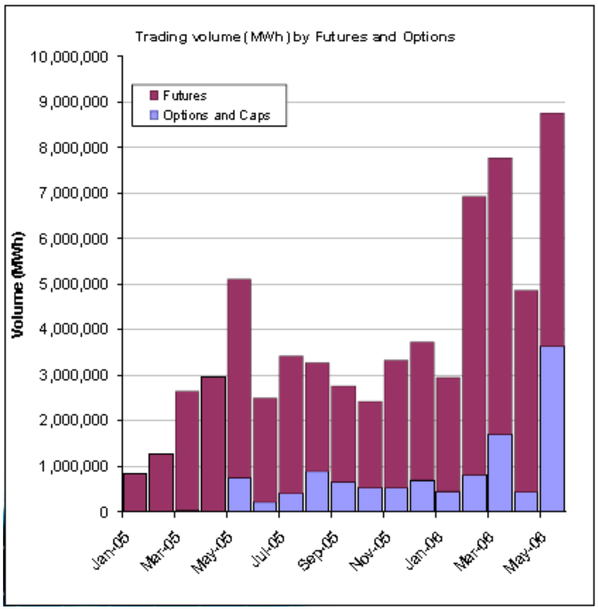
- Since listing in September 2002, 49,351 Futures & Options Contracts have traded which is the equivalent of 87,521,000 MWh, and has a face value of approximately $3.676 billion (as at Feb 2006).

www.d-cyphaTrade.com.au 1800 330 101 4

Table 1 was provided in a recent presentation by d-cyphaTrade and describes the increasing SFE electricity futures trades during 2005-2006 (e.g. 22,846 total contracts for a volume of 42TWh or 22% of physical energy).

[2] d-cyphaTrade is a market leader in delivering exchange traded energy derivatives to the Australian market.

Graph 1 – d-cyphaTrade Trading Volumes by Futures and Options (Jan 2005 to May 2006) - Source: d-cyphaTrade



In May 2006 d-cyphaTrade saw a record monthly volume of 8.6 million MWh of futures and options contracts traded (see Graph 2). The total traded MWh during this period represents over 39% of the underlying NEM system demand (NSW, Qld, Vic and SA), which is an increase of 240% on the equivalent period during 2005.

Much of the recent investment in the NEM has been supported by long-term bilateral contracts. The ERAA does not agree that lack of transparency in financial markets is a barrier to new investment. A healthy bilateral contract market exists for potential investors to underwrite investment.

Question 34 – The role of DSR in terms of supply side reliability outcomes

DSR is an essential element of supply reliability management. It is inefficient to plan the bulk supply system to meet a 1 in 10 year extreme event. DSR complements generation by reducing the peakiness of demand and allowing more efficient utilisation of generators.

Retailers currently enter into DSR arrangements as a defence against high price events. Under some circumstances, it can work out more efficient for a retailer to enter into DSR arrangements than purchase financial cap contracts.

Realising the full benefits of DSR in the NEM is currently frustrated by regulated retail price caps. The ERAA supports the removal of retail price caps to allow further DSR to be pursued through innovative price structures. The ERAA's position on retail price regulation is outlined in the ERAA Policy Position Paper "*Retail Price Regulation*" which is attached to this submission.

Question 35 – Operational changes to improve the effectiveness of price mechanisms

The NEM spot price is designed to provide an economic signal upon which producers and consumers of electricity base their decisions to produce and consume. This signal can be distorted when network constraints impact on the setting of the spot price for a region. This can result in a very high spot price for a region, at a time when that region has significant capacity not dispatched. This is because that available capacity cannot access the regional reference node due to network constraints.

A high spot price signals the need for investment in generation within a region. However in this case the issue is location specific and would benefit from network investment.

The ERAA supports work currently being undertaken to improve the transmission investment framework and work to develop transmission operational incentives. Efficient investment in and operation of the transmission network will improve the reliability of the bulk supply system, enhance competition in the NEM, and reduce the occurrence of inaccurate pricing signals from dispatch. The ERAA also recommends that the AEMC investigate options to reduce the impact of network constraints on the spot price.

Intervention Mechanisms (Question 38 – 47)

Question 38 – NEMMCO intervention

NEMMCO should only intervene in the NEM as a last resort measure following a multiple contingency event (the NEM is designed to withstand single credible contingencies), or in the case of obvious market failure. Continued intervention by NEMMCO distorts efficient market signals, complicates retailers' ability to manage costs, and prevents the market from managing itself.

The ERAA believes NEMMCO intervenes in the NEM too early, which reduces the opportunity for a market based response. This is often due to overly conservative demand forecasts.

Question 39 – Reliability Safety Net

The current Reliability Safety Net provisions impede the NEM from delivering efficient market based responses to supply shortfalls and result in inefficient costs passing to end-users.

The Reserve Trader Provisions in particular are inefficient since:

1. Intervention by NEMMCO prevents efficient market driven responses to manage shortfalls.
2. Reserve Trader to contract DSR interferes with the efforts of retailers to contract DSR, reducing the ability of the market to respond on its own. It is also likely that NEMMCO would be purchasing the same capacity available to retailers for DSR.
3. Reserve Trader disadvantages prudent retailers that have acquired appropriate DSR at some cost by requiring retailers to pay for the capacity again through reliability safety net charges.

4. The cost of reserve trader is uncapped, unpredictable, and has the potential to be large. This creates an unmanageable risk for retailers.
5. Retailers have relationships with loads and are thus better placed to negotiate DSR contracts than NEMMCO.
6. Contracts with demand side providers that would have responded to the high price signal without the contract distorts the market.

Retailers are incentivised to manage demand spikes. For an extreme demand event, it is unlikely that retailers would have sufficient contract cover, and would thus be exposed to high pool prices for the unhedged portion of their load. Retailers are thus incentivised to curb physical demand back to the contracted volume by exercising DSR arrangements.

For the past two summers NEMMCO has acquired reserves through Reserve Trader, but has not needed to dispatch those reserves. This action was at a combined cost of $5.4m, which was passed to end-users for no benefit.

The Reserve Trader provisions in the Rules should not be extended past the expiry date of 30 June 2008. These arrangements do not contribute to the market objective because the NEM can provide the same service more efficiently than NEMMCO. In the interim period NEMMCO should use less conservative demand forecasts to avoid intervening so early.

Question 46 – Next review of reliability settings

See Question 18.

If you have any queries on the content of this submission, please contact me on (02) 9369 4296.

Yours sincerely,

[Transmitted Electronically]

Alastair Phillips
A/Executive Director
Energy Retailers Association of Australia
aphillips@eraa.com.au

Investigation into the Administered Price Capping Mechanism

January 2004

Disclaimer

This report has been prepared by Creative Energy Consulting for the sole use of the Energy Retailers Association of Australia (ERAA) in evaluating the current Administered Price Capping mechanism and considering possible changes to this mechanism. It should not be relied upon by any other person or for any other purpose. The opinions expressed in this report are those of the author and do not necessarily represent those of the ERAA or its constituent members.

1. Introduction

This report describes a review - for the Energy Retailers Association of Australia (ERAA) - of administered price capping (APC) mechanisms to mitigate energy trading risks during periods of extreme prices.

The following sections of this report

- identify the objectives of such mechanisms and desirable characteristics that the mechanisms should possess;
- describe how the current APC mechanism operates;
- assess the extent to which the current CPT mechanism achieves the objectives and possesses desirable characteristics;
- describe and evaluates potential alternative CPT mechanisms; and
- apply some of these mechanisms to historical NEM price data

This report builds on an earlier “objectives and options” paper which has been circulated and presented to ERAA representatives.

2. Objectives

Reliability Panel Considerations

The CPT mechanism was proposed by the Reliability Panel in its July 1999 report on VoLL[1]. It was introduced in the Code on 29th June 2000. The CPT level proposed by the Panel was scaled back by half by the ACCC, in line with its scaling back of VoLL.

Thus the CPT was introduced at the same time as VoLL was increased and also replaced an earlier "FM" mechanism which performed a similar function. The Panel regarded the proposed increase in VoLL and the introduction of the CPT as "tightly linked". In other words, an increase in VoLL would have been inappropriate if the CPT mechanism had not accompanied it, although it was also noted that a CPT mechanism would be needed even without the increase in VoLL.

The VoLL paper refers to the CPT as a "risk management provision" and a "risk capping mechanism". It is not specific on how such risks are defined or capped, although it does refer to two categories of risk: "trading risk" relating to both price and volume risk, and "collection risk" which it relates primarily to NEM credit prudentials. A clear concern of market participants is the development of a "systemic" market failure, through cascading credit defaults in the spot or forward markets.

The Panel makes clear the importance of mitigating risk, whilst preserving as far as possible the market to use price signals to provide supply reliability. It recognises that risk is inherent in these price signals, and too strongly mitigating such risk may interfere with the efficient operation of the market and so compromise supply reliability.

Assumed Objective of CPT

For the purposes of this investigation, it is postulated that the objective of the CPT mechanism is to:

- cap risk on market participants (MPs) in "abnormal" market conditions; whilst
- minimising the impact on market clearing and supply reliability under "normal" market conditions

It is assumed that "risk" primarily relates to "worst case losses", often referred to as "value at risk" (VaR). VaR levels are the basis on which risk capital is allocated to trading functions and credit prudentials are managed by NEMMCO (for the spot market) and MPs (in relation to bilateral transactions).

[1] Review of VoLL in the national electricity market – Report and recommendations.

However, this stated objective begs several questions: in particular:

- How are "normal" and "abnormal" market conditions differentiated?
- Over what period should the VaR be capped (eg over one week, one month or one year)?
- What exposure to spot prices would a "prudent" MP is expected to have?

These questions are considered below.

Normal and Abnormal Conditions

It is known and accepted by MPs that the spot market is quite volatile, and periods of high prices are expected to occur from time to time. These are likely to be related to the influence – and particularly the confluence – of:

- extreme weather (leading to high demand);
- generator forced outages; and
- transmission forced outages

Although such conditions are rare and irregular, they are predictable in the sense that they are highly likely to happen at some point, although the time of occurrence cannot be forecast. In this sense, they are "normal" market conditions, albeit at one end of the "normal" spectrum.

On the other hand, there are market conditions which arise from specific events which are expected never to occur but nevertheless can credibly happen: for example:

- major industrial action
- common mode failures (or precautionary shutdowns) of large numbers of separate power plants;
- extreme "natural" events such as cyclones or earthquakes;
- systemic market failure, for whatever reason (eg California crisis)
- major transmission failure: eg destruction of a key substation or transmission circuit;
- terrorism or sabotage

These events broadly fit into categories of "Force Majeure". They are distinct from the extremes of normal conditions in that there is a clear underlying and unexpected cause, rather than a coincidence of expected (albeit unusual) events. Furthermore, in contrast to normal conditions, they are conditions with which the market was not designed to cope and during which the community would not necessarily expect supply reliability to be preserved.

The above conditions all have the potential to create sustained market disruption. However, other events – generally transmission related - may lead to transient disruption, lasting perhaps from only a few hours up to a few days: for example, islanding, non-credible transmission contingencies or system operational failures. Although of short-duration, these conditions could cause many consecutive hours of load shedding – and hence VoLL pricing – and perhaps give rise to value-at-risk of similar magnitude to the more extended abnormal conditions.

Given their short duration, it is probably preferable for these types of conditions to be mitigated through the "market suspension" provisions of the Code, rather than administered pricing. Market suspension allows pre-dispatch prices to be used in place of real-time prices, which would in turn be replaced by administered prices if the conditions extended beyond 24 hours so that "normal" pre-dispatch prices were no longer available.

NEMMCO can only declare market suspension under one of three conditions:

- the system has collapsed to a "black system"
- it has been directed to do so by a jurisdiction, following a declaration of a state of emergency; or
- NEMMCO has determined that it is impossible to operate the market in accordance with the provisions of the Code

These provisions leave NEMMCO with significant discretion. It is possible that NEMMCO may decide not to suspend the market even when conditions are fairly extreme: for example, a significant percentage of load might be shed, but so long as transmission voltages are maintained it might not constitute a black system.

It is understood that NEMMCO intends to develop specific criteria for determining black system conditions. However, it may also be appropriate for the Code criteria for market suspension to be broadened somewhat. Although market suspension sounds extreme, it really only directly affects the setting of spot price, as described above, and may actually have less impact than the administered price cap.

Given this approach, it is therefore *not* considered to be an objective of the APC arrangements to mitigate risks during short-lived transmission problems.

Period of VaR Accumulation

The period to be considered is related to both the "abnormal" market conditions to be mitigated and the alternative risk mitigation actions that can be taken.

A feature of the FM-type events is that their duration can be extended and possibly open-ended, from perhaps a few months to a year or more. In contrast, normal extremes are more likely to last from perhaps a few weeks up to a month. Thus, to mitigate risk during abnormal conditions, the timescale of the mitigation mechanism needs to be in months rather than weeks.

What mitigating actions are possible for a market participant with a large exposure to abnormal market conditions? A retailer may be able to raise prices to customers, but this might take from several months (in relation to regulated customers) to a year or more (for competitive customers). It might exit the market by selling its customers base or its business to a competitor or new entrant, which would also likely take several months.

A generator could perhaps renegotiate its contractual position or its debts, raise capital in the market or sell its assets or its business. All of these would take several months.

Whilst these actions do not necessarily avoid losses for individual MPs, they can at least prevent individual difficulties becoming systemic. Thus, it seems appropriate to be considering VaR over a period of anything from several months up to a year.

Prudent Market Participant

A prudent MP should be able to hedge against the vast majority of trading risks – under normal conditions - through the trading of hedge contracts. It should not be an objective of the CPT-mechanism to protect imprudent participants who, as a result, find themselves in difficulty during normal conditions. Indeed, a major concern in introducing any risk mitigation mechanism is the “moral hazard” that MPs may deliberately adopt riskier trading strategies as a result.

It is considered that:

- a prudent retailer should have sufficient hedge contract cover to hedge against the extremes of normal conditions: for example to cover 10% probability of exceedance (PoE) maximum demand; and
- a prudent generator should have sufficient generating capacity to back sold hedge contracts with one unit on forced outage, or alternatively have some sort of “insurance” arrangements to cover a second unit on forced outage[2].

A retailer might argue that insufficient hedge contracts are available, or are not sold “at the right price”. Such arguments are not unreasonable in the short-term, but in the medium-term retailers have the option of financing or developing new generation (eg peakers), losing customers, or even selling their business, and so the continuation of an imprudent “speculative” trading position should be regarded as a deliberate trading strategy rather than a failure of execution.

A prudent generator will nevertheless be exposed to risk of multiple generating plant failure or unavailability. It is also likely to be exposed to transmission risk, either intra-regional (through being constrained-off) or inter-regional (again through SRA instruments or similar).

[2] This might be, for example, through “co-insurance” where two generators mutually agree to cover each other for half of the capacity of a unit on forced outage or through cap contracts which only become active during a unit forced outage.

With a high level of contract cover, a prudent retailer should rarely be exposed to significant downside market risk, even during abnormal conditions, since abnormal conditions would not normally increase the demand level. A retailer will be exposed, however, if some of a generators risks are "passed through" – eg in "non-firm" hedge contracts.

Both retailers and generators may be exposed to inter-regional transmission risk through SRA instruments or similar. Generators may also be exposed to intra-regional transmission risk, by being constrained off during high price periods.

Finally, all MPs may become exposed should their contract counterparties default. Whilst credit risk management and prudential mechanisms should largely protect against individual defaults, they will not protect from multiple defaults as a result of systemic market problems.

Note that extreme downside market exposure requires an MP to have a short trading position at time of extreme (high) market prices. Risk exposure from a long trading position is unlikely, since extreme, low market prices are unlikely to be sustained for a significant period. Furthermore, high prices *per se* should not lead to significant losses for a prudently hedged MP.

3. Desirable Characteristics of an APC Mechanism

Introduction

Before looking at options for changing the APC mechanism, it is useful to establish what the desirable characteristics of such a mechanism are. These will draw on the objectives discussed in the previous section, but will also consider the practicalities of operating the APC regime.

Caps Cumulative Price

The assumed objective of the APC is to cap value at risk for a prudent participant over the abnormal period. A prudent participant should ordinarily not be significantly short to the spot market at times of high prices. However, under abnormal conditions, some participants may find themselves short due to:

- failure of contracts, whether through the exercising of FM or similar provision or through counterparty default;
- inability to generate at full capacity due to major generation or transmission outages

If it is assumed – perhaps simplistically – that the abnormal conditions remove a fixed MW of contract or generating cover, then the consequential losses will be proportional to the cumulative price over the period: for example, if cumulative price is $100/kW and spot exposure is 100MW, then losses would be around $10m. Thus, capping of cumulative price is a reasonable surrogate for capping of VaR, and does not require knowledge or specification of a "prudent" participant's trading portfolio.

Conversely, a participant that has confidence that the cumulative price will not exceed a specified cap can easily calculate their value at risk simply by multiplying the cumulative price cap by the worst-case spot exposure over the period.

Costs are Hedgeable

The above discussion implicitly assumes that the extreme prices are hedged by normal forward contracts: ie that they will feed through the spot price. However, abnormal market conditions can also create "uplift" costs: costs which are shared between retailers and are recovered outside of the spot price and so not usually covered by hedge contracts. Thus, whilst a prudent retailer may only be exposed to a few percent of extreme spot prices, they are likely to be exposed to 100% of uplift costs.

Thus, it is important that uplift costs do not add significantly to retailer VaR over the abnormal period.

Low Impact

The second part of the objective is that the impact on market clearing and supply reliability under normal conditions should be minimised. This can be done by:

- ensuring that APC provisions are not triggered during normal conditions; and
- where APC provisions are wrongly triggered, the impact is minimised

Due to the difficulty in delineating normal and abnormal conditions, there is a clear tension between this characteristic and the need to cap cumulative price during abnormal conditions.

Mechanistic

Extreme market conditions are likely to give rise to substantial gains or losses for different participants, depending upon whether they happen to be long or short to the spot market. The "losers" will, of course, wish for the price capping to commence as soon as possible, whilst the "winners" will generally be happy for the high prices to continue[3]. Thus, the operation of the APC-mechanism may be highly contentious and closely scrutinised. Where its operation requires the use of discretion by some party, it is possible that its decisions may be disputed, giving rise to further uncertainty. The decision-maker may then be inclined to act "conservatively" – ie in a way designed to minimise the likelihood of disputes, rather than necessarily in the best interests of the market. In any case, the application of discretion is inherently unpredictable, thus creating further uncertainty for the market.

Thus, it is desirable for discretion to be kept to a minimum and for the APC rules to be as prescriptive and mechanistic as possible.

Real-time

Non-dispatched participants rely on the publication of spot prices in real-time to make commercial decisions on generation or consumption. Thus, it is desirable for this to continue during APC periods.

If prices cannot be published in real-time, it is still desirable for these to be finalised prior to settlement. Post-settlement price revision will lead to settlement reconciliations in both the spot and contract markets. Where participants run into cash-flow difficulties during abnormal conditions, it is possible that post-settlement mitigation of prices may be too late to prevent default or insolvency.

Thus, it is desirable that prices can be published in real-time, and essential that prices are finalised pre-settlement.

[3] Although, if the problems lead to systemic market failure, the "winners" could quickly become "losers"

Simple

Simplicity is always desirable, of course, although not always attainable. In relation to APC-mechanisms, it is particularly important simply because so much is potentially at stake and any mistakes – by NEMMCO or market participants – may be extremely costly.

4. Current CPT Mechanism

How it Works

The CPT mechanism consists of 4 components:

- a "trigger" mechanism which determines the commencement of an administered price cap (APC) period;
- a "reset" mechanism, which determines the conclusion of the APC period
- the APC levels which apply during the APC period; and
- compensation provisions for constrained on generators

These components are described below.

The trigger occurs when the rolling weekly cumulative price (the sum of trading interval prices over the previous 336 trading intervals) exceeds $150,000. Put another way, at the trigger level, a generator dispatched for all of these 336 trading intervals would receive $75,000 for each MW dispatched, or $75/kW. For clarity, cumulative prices will be expressed in $/kW in this paper.

The "reset" occurs when the weekly cumulative (uncapped) price falls below $75/kW, except that:

- the APC period, once commenced, must continue at least until the end of the trading day, and;
- NEMMCO can continue the APC period into the following trading day, if it expects that a new APC period would be triggered in any case on the next business day

The APC level is $100/MWh for peak periods[4] and $50/MWh for other periods. Note that this is a cap level, so spot prices may be set below these levels, but not above them.

Compensation is paid to generators that are "constrained-on": ie dispatched generators whose offer prices are higher than the (capped) spot price. The Code is not prescriptive on how this compensation will be calculated, leaving it to an appointed expert adviser to determine a "fair and reasonable" amount. However, it is notable that *actual* generation costs are not amongst the factors that the Code requires the adviser to take into account. This differs from compensation for directions, where generation costs are explicitly described.

Thus, the Code potentially allows for compensation to be based on offer prices, leading in effect to a "pay-at-bid" market during APC periods. One would expect that generators would rebid so as to have their offer prices close to the (uncapped) spot price, so the

[4] 7am to 11pm on business days

compensation may have the effect of paying the generators the uncapped spot price and making the capping process ineffective.

The Code does not provide for compensation for a demand-side bidder that is "constrained-off" during an APC period: ie which is dispatched to reduce load, although its bid price is higher than the (capped) spot price. This makes it unlikely that dispatch bids will be submitted during APC periods.

Effectiveness in capping cumulative price

The CPT mechanism requires that a *minimum* of $75/kW accumulates before the APC period is triggered. In fact, substantially more could accumulate, if the cumulative weekly price stays high – but below the CPT – for a prolonged period. For example, prices could potentially accumulate at $70/kW/week (ie just below the trigger level): around $300/kW/month or $3600/kW/year: well in excess of total asset values of NEM participants.

During the APC period, the capped prices can be as high as $74/MWh, or around $12/kW/week. However, they are likely to be much lower than this in practice, since spot prices in individual trading intervals are likely to be significantly below the cap for most of the time.

Once the weekly cumulative price falls back below $75/kW, the mechanism "resets" and prices can accumulate once more at up to $75/kW/week before a 2nd APC period is triggered. It is quite credible that this might occur. For example, suppose a "force majeure" event has taken out a significant proportion of generation capacity: eg 10%. This may lead to extreme prices during periods of hot weather, but just "high" prices during periods of milder weather. Thus, a two week hot spell could trigger an APC period, a following mild spell could reset it and a further hot spell could trigger a second APC period. This might continue through the summer season.

Thus, the current mechanism does not appear to be effective in capping cumulative annual prices in relation to a sustained, underlying FM-type condition.

Amount of Unhedged Costs

A possible weakness of a CPT mechanism is that it exposes MPs to spot prices at the commencement of the extreme conditions – when spot exposure may be greatest. This may not be significant where the CPT relates only to one week, but will become more significant should the mechanism be varied to make this period longer.

Another potential major contribution to VaR for a prudent retailer is the compensation payments awarded to constrained-on generators during the APC period. Because these costs are recovered outside of the spot price, they are not hedged by typical forward contracts. In the event that the compensation process effectively leads to a pay-at-bid market, the APC will have the effect of exposing retailers to possibly extreme clearing prices for 100% of their demand, rather than the small percentage of exposure outside of the APC period.

Impact under normal conditions

As noted above, extremes in market prices that occur only for a few weeks every 5 to 10 years may be considered normal market conditions, albeit at the extreme end of the normal spectrum. A peaking plant requires a capital return of around $50/kW each year, and so plant that only expects to be dispatched during these "normal extremes" may then require $250/kW to $500/kW over that period: ie 5 to 10 years of capital contributions over a period of a few weeks. However, the CPT mechanism caps the return at $75/kW/week[5] (if the APC period is not triggered) or $75/kW for the extreme period (if the APC is triggered). Thus, the CPT mechanism may significantly discourage the development of the peaking capacity needed to ensure supply reliability during normal conditions.

The contribution to capital return for a dispatched generator is the amount by which the spot price exceeds the variable costs of operation. This will be referred to as the "premium", based on a specified variable cost, or "strike price". Thus, a peaking plant with $100/MWh variable costs receives a capital contribution equal to the premium for a $100/MWh strike price.

Because the APC caps prices at or below $100/MWh, the premium at this strike price is zero during an APC period. However, plant with lower variable costs may continue to receive a premium. In fact, the cap will reduce the *absolute* amount of premium by a similar amount for all plants, but the *relative* loss will be greater for plant with higher variable costs, since it would expect to recover all of its capital return during high price periods. Therefore, the APC in a sense "discriminates" against peaking plant.

Finally, because there is no compensation to "constrained-off" demand-side bids (DSBs) during APC periods, the incentive for demand side management – whether centrally- or self-dispatched – is removed. This could potentially exacerbate any shortfall of supply, leading to greater amounts of involuntary load shedding than would be the case outside of APC periods.

Other Desirable Characteristics

NEMMCO has no *discretion* on when to commence the APC period, but has some limited discretion as to whether to extend it to the following day, even if cumulative prices have fallen below the CPT. NEMMCO's discretion could potentially be reduced if they described a mechanistic procedure for applying this discretion: eg relying on pre-dispatch prices to see if the CPT is likely to be reached on the following day.

The expert panel appointed to recommend a "fair and reasonable" amount of compensation for constrained-on generators appears to have substantial discretion, as does NECA in determining whether to follow the panel's recommendation.

NEMMCO declares an APC period as soon as the CPT is reached. Subsequently, all prices are capped. This is done by NEMMCO in *real-time*. Similarly, the declaration of the end of the APC period is also made in real-time.

---

[5] In practice, the maximum return will be less than this, since the peaker will not be dispatched for all periods, and operating costs must be deducted.

The operation of the CPT trigger and the application of the price cap are *simple* to understand and model.

Conclusions

The current CPT-mechanism may be ineffective in achieving its objectives. In particular:

- cumulative prices and VaR during FM-related conditions which are sustained for several months are not effectively capped at any level;
- capital returns to peaking plant required to maintain supply reliability during normal market conditions may be substantially reduced by activation of the APC during “normal extremes” in the market;
- the provisions for compensating constrained-on generators during APC periods are unclear, and could potentially lead to a “pay-at-bid” market, against which hedging contracts would not provide any protection;
- capping prices at $100/MWh during APC periods removes any premium earned by peaking generators and removes incentives for demand-side management.

The next section describes possible options for changing the CPT-mechanism.

5. Options for Change

Introduction

The previous section describes the 4 elements of the current APC/CPT mechanism:

- the trigger criteria
- the reset criteria
- the APC level
- arrangements for generator compensation

This section describes some options for changing these elements. The options need not be mutually exclusive, in fact changes to the 4 elements can be made largely independently – for example, a longer CPT trigger period could combine with a lower APC level - although most combinations of changes are unlikely to give rise to a coherent alternative to the current mechanism. Hence, the following section describes and analyses a number of “straw men” combinations, which represent some plausible alternative combinations, but not necessarily the only ones.

Changing the trigger criteria

Options

The trigger criteria for commencement of the APC period could be varied by:

- changing the level of the CPT
- changing the period over which the CPT accumulates

Evaluation

By lengthening the trigger period, perhaps to a duration similar to the typical duration of abnormal market conditions, the likelihood of multiple triggers (and hence a high cumulative price) over the abnormal period will be reduced. To prevent incorrect triggering during “extreme normal” conditions, the CPT level would also need to be increased. However, the increase would not need to be proportional: for example, a $75/kW CPT for a one-week period need not translate into a $750/kW CPT for a 10-week period. This is because, whilst the one week CPT needs to be high so as not to be triggered during extreme normal conditions, it is highly unlikely that such conditions would continue for 10 consecutive weeks. Thus, a CPT of, say, $250/kW might be sufficient to prevent inappropriate triggering.

Changes to these variables have no effect on the other desirable characteristics of the CPT mechanism.

Conclusion

The period which is considered in the APC mechanism should be similar to the likely duration of the abnormal conditions. The trigger levels should then be set so as to best delineate “extreme normal” and abnormal conditions.

Changing the reset criteria

Options

The current mechanism will "reset" (ie the APC period will end) after a period of lower prices. If the reset occurs before the underlying abnormal conditions have been resolved, high price could continue to accumulate, potentially substantially in excess of the CPT. The aim of the reset mechanism should be to reset only once the abnormal conditions have ended.

Changes could be made to the reset criteria: for example

- increasing the discretion of NEMMCO to look ahead and retain the APC period if the CPT is expected to be exceeded in the near future
- setting a minimum length for the APC period (eg one month)
- resetting only when rolling cumulative prices have been below the threshold continuously for a given period (eg one month)
- introducing a "cumulative price reset threshold" at a lower level than the CPT trigger

The first option might allow NEMMCO to extend the APC period where the circumstances underlying the initial CPT breach were continuing. For example, a major generation outage may, when coinciding with hot weather, lead to the CPT being exceeded. However, a few days of milder weather may cause cumulative prices to fall back below the CPT again. If, however, the major generation outage was continuing and future hot weather was expected, NEMMCO could extent the APC period, rather than letting a second tranche of high prices feed through to the market.

The last two options introduce "hysteresis" into the mechanism: ie making it "harder" to reset than to trigger initially. For example, the trigger threshold could remain at $75/kW, but the reset threshold could be set at $15/kW. The APC period would then not finish until the weekly cumulative price fell back below this level. Thus, prices would need to fall back to more normal levels before the APC period ended. This might better indicate that the circumstances underlying the extreme prices had ended, and prevent multiple triggering during a single abnormal period.

Evaluation

Increasing discretion is considered undesirable, and so we should confine our considerations to alternative mechanistic methods.

Typically, during abnormal market conditions, there will be periods of respite – for example due to milder weather – when prices will fall back – only for extreme prices later to return. It would not be appropriate for the reset to operate during such a respite. The "hysteresis" introduced by the last two options above would tend to prevent this happening, without excessively delaying the reset once normal conditions have truly returned.

Conclusion

Some sort of “hysteresis” should be incorporated within the reset mechanism, to prevent multiple trigger/reset occurrences during a single abnormal period. This can be seen as an alternative to having a longer accumulation period.

Using a Multivariate Trigger

Options

The current trigger is “univariate” in that it depends upon a single variable: spot price. The CPT mechanism replaced the earlier “FM trigger” which used a different variable: hours of load shedding.

Ideally, the trigger mechanism should differentiate between the “normal extremities” of the market, and FM-related market extremes. Conventional supply contracts in other industries often do this through an FM clause, which specifies a list of “FM events” as triggers. It is understood that the possibility of an FM clause was considered by the Reliability Panel and by NECA, but that it was found to be impractical to clearly specify all of the possible FM events[6]. Some FM conditions are provided for in relation to market suspension, specifically market operator problems (such that the market cannot be operated in accordance with the Code) and “black system” meaning a substantial loss of load due to widespread transmission failure.

Even if it is not possible to specify all potential FM-type events, a number of the more obvious ones could be included within the trigger mechanism, in parallel with a price-driven trigger.

Alternatively, FM-type conditions might be better identifiable by looking at several market variables, such as generation availability, amount of constrained-off generation, amount of load shed and so on. Significant departures from forecast levels (eg from PASA or the TNSP Annual Planning Reports) might be better indicative of an underlying FM-type event than simply the cumulative spot price.

Evaluation

The difficulty with a multivariate trigger is to make it mechanistic, whilst ensuring that it encompasses all possible types of abnormal condition. For example, a trigger that looked for an abnormal demand-supply balance may not trigger during abnormal ‘”commercial” conditions, such as failure of market participants and consequential termination of contractual arrangements.

However, a multivariate trigger could operate in parallel with a price-driven trigger, such that an APC period is triggered should *either* mechanism activate. This has the potential advantage of triggering earlier when an “abnormal” event has clearly taken place, but high prices have not yet accumulated.

[6] However, this issue is not discussed in the VoLL report, although it does state that the Panel believes that the CPT mechanism more reliably caps risk than the FM-trigger that it replaced.

Conclusion

A Multivariate trigger could operate in parallel with the price-driven trigger, but is unlikely to be sufficiently comprehensive to operate on it own.

Changing the APC

Options

Because the APC removes any “premium” above $100/MWh, whilst allowing average price levels to reach $74/MWh, it has a more marked effect on peaking plant than on baseload plant. This problem could be corrected in a number of ways:

- change the APC profile
- map the APC to trading intervals through a ranking mechanism
- use an administered price level (APL) instead of an APC

The APC profile could be changed, for example, by reducing off-peak APC and increasing peak APC. Alternatively a “super-peak” APC level could be introduced, to allow much higher prices for just a few hours per day. The profile could be changed such that the average APC – and hence the worst-case average price – remained at $74/MWh, say.

The problem with a “peaky” APC is that there is no guarantee that peaking plant would be running during the “super-peak” hours, particularly given the abnormal circumstances likely to be underlying the CPT trigger. A “ranking” mechanism would ensure that the higher APC levels would be applied to the highest spot price periods. For example, the 8 highest-priced trading intervals in a day could be capped at $500/MWh, the 8 next highest capped at $100/MWh, and so on. Thus, peaking plant should normally receive those highest prices, but the overall price is still capped by the APC.

An administered price level sets, rather than caps, the spot price during the APC period. This creates greater certainty over what prices will be over this period. However, the APL would need to be set at a much lower level than the current APC to give an equivalent expected price level, since the APC may not actually be reached during many periods.

Evaluation

Options to change the APC introduce significant complexity and may prevent publication of prices in real-time, without really significantly changing the impact, on peakers in particular, of incorrect triggering of APC during normal periods. For example, the super-peak period suggested above only allows a weekly maximum premium for of $3.2/kw above the current $100/MWh price cap, compared to potentially 10 times this amount that has been lost.

Allowing higher prices during the APC potentially improves incentives to DSM during the APC period. However, the complexity and uncertainty of these options is likely to put off demand side bidders anyway. A better approach may be to provide compensation to “constrained-off” bidders, just as it is provided to constrained-on generators. This is discussed further below.

Conclusion

Options for varying the price cap are likely to introduce complexity and “retrospectivity” without significantly reducing the potential impact of incorrect triggering of the APC during normal periods.

Cumulative Premium rather than Price

Options

The APC trigger and reset mechanism could be based on cumulative premium above typical peak price levels ($100/MWh, say) rather than cumulative price.

Evaluation

Abnormal market conditions are likely to be characterised by increased price volatility as well as increased price levels. In particular, prices may spike repeatedly at levels close to VoLL as lack of reserve problems occur during peak demand periods.

Higher price volatility also increases risks seen by prudent participants, since even if they are hedged against spot price on average, they may become short at times, leading to large losses if these times coincide with the price spikes.

A simple measure of price volatility is the cumulative premium (as discussed earlier) above normal peak price levels ($100/MWh, say) rather than the cumulative price. A general rise in prices at levels below $100/MWh will generate no cumulative premium, but repeated price spikes will create substantial premium.

Cumulative premium is also a measure of the potential contribution to capital costs earned in the spot market by peaking plant, which is likely to be most sensitive to the impact of an APC mechanism. Thus, a cumulative premium threshold can be set at a level which “guarantees” a peaker a certain level of capital return. For example, if the annualised capital cost of an OCGT is $50/kW, then a cumulative premium threshold of $250/kW “guarantees[7]” a peaker 5 years’ worth of capital contributions before the APC period is triggered. In contrast, a cumulative *price* threshold of $250/kW could be largely accounted for by prices below $100/MWh (depending upon the accumulation period, of course), leaving little guaranteed premium for peakers.

Using a cumulative premium does not affect the other desirable characteristics: ie hedgeable, mechanistic, real-time and simple.

Conclusion

A cumulative premium trigger may be preferable to a cumulative price trigger, given its ability better to “protect” peaking plant and to identify abnormal periods.

---

[7] Of course, the peaker would need to be fully dispatched whenever prices exceeded $100/MWh and would also need to be fully exposed to the spot market.

Cumulative Price Cap

Options

Since a key objective of the CPT mechanism is to limit the worst-case level of cumulative prices, it may be appropriate to consider a cumulative price[8] cap (CPC) rather than a price cap in each trading interval. In other words, rather than using the cumulative price as the trigger and then subsequently capping prices, prices could be capped in a way which prevents cumulative *capped* prices from exceeding the threshold in the first place.

Prices can be capped *retrospectively* or *prospectively*. A retrospective cap would monitor cumulative prices regularly and then, if the cap is exceeded, retrospectively reduce prices. For example, if there were a weekly price cap of $30/kW, and uncapped prices for the previous week were $60/kW, these prices could be capped or scaled back retrospectively to ensure that the weekly cumulative *scaled* price was no more than $30/kW

Whilst this might be suitable for a short accumulation period (eg one week) it would be less suitable for a longer period (eg one year) where prices would be rescaled long after settlements, creating the need for substantial "post-final" settlement adjustments.

An alternative "dynamic scaling" mechanism could dynamically adjust the scaling factor applying to "current" prices so that the CPC is not exceeded. For example, suppose that we have a CPC of $500/kW applying over a rolling accumulation period of 52 weeks. Suppose further that the cumulative (unscaled) price for last week is $50/kW and the cumulative amount of the *scaled* prices for the previous 51 weeks is $480/kW. Then we can see that if last week's prices are unscaled, the cumulative amount for the last 52 weeks will be $530/kW. The CPC can then be enforced by scaling last week's prices by 40%, so that the cumulative amount of scaled prices is now $500/kW[9].

Thus, prices can be scaled each week (and settled within the normal settlement calendar), whilst an annual CPC is maintained. A similar approach could apply instead to maintaining a cumulative premium cap.

Multiple cumulative price caps could be nested. For example, a 5-week CPC of $100/kW could be nested within a 50-week CPC of $500/kW. Prices would be first adjusted to enforce the 5-week CPC (eg through dynamic scaling) and then further adjusted, if necessary, to enforce the 50-week CPC. This would prevent a situation, for example, where extreme prices led to the $500/kW being accumulated in a short-time (eg one month) and then prices needing to be scaled back strongly for the remainder of the year.

A *prospective* price cap, on the other hand, would apply scaling or capping to future prices based on an anticipation that, without such capping, the cumulative price cap would be exceeded. To avoid introducing discretion, this would need to be done in a

[8] All of these options can be applied equally to a cumulative premium cap

[9] Or alternatively, by reducing VoLL so that the weekly cumulative price is similarly reduced to $20/kW.

mechanistic way, such that, as the cumulative scaled price approached the cumulative price cap, the level of the APC could be progressively reduced. For example, suppose that the cumulative price cap is $250/kW. Then VoLL could be set as follows:

Cumulative scaled price ($/kW)	**VoLL ($/MWh)**
Less than 50	10,000
Between 50 and 100	5,000
Between 100 and 150	2,000
Between 150 and 200	1,000
Between 200 and 250	500
Above 250	100

The rolling cumulative price (over the accumulation period) would be published at the end of each day (or even each trading interval) by NEMMCO. Once the rolling cumulative price exceeded $50/kW, NEMMCO would inform the market that VoLL, going forward, had been reduced to $5000/MWh[10]. If the rolling cumulative price continued to grow then, once it reached $100/kW, NEMMCO would inform the market that VoLL has reduced to $2000/MWh, and so on.

This approach will not *guarantee* that cumulative prices never exceed the cap, but it makes it unlikely. Because VoLL is always notified in advance, spot prices can continue to be calculated and published in real time.

It is possible with this approach that VoLL is reduced unnecessarily: ie when the uncapped priced would not have exceeded the cumulative price cap.

Evaluation

A cumulative price cap approach guarantees that the cumulative price will not be exceeded, but then so does a CPT mechanism, so long as the accumulation period is long enough to prevent multiple triggering.

However, its advantage can stem from capping prices early, before the cumulative price threshold has been reached. This is likely to be the period when participants are most exposed: ie when spot prices are at their most extreme. Thus, in a sense, the costs are more "hedgeable" in this approach.

In enforcing a cumulative price cap, we can use either variable scaling or variable capping and can then apply this either retrospectively or prospectively.

The problem with scaling prices is that it, if the scaling is known or anticipated in advance, generators will simply scale up their bids by an equivalent amount to counteract it, subject to the scaled up price remaining below VoLL. Thus, a preferred

[10] Thus the spot price would be capped at $5000/MWh. However, generators would be allowed to continue bidding at prices up to $10,000/MWh, to prevent the need for a large amount of rebidding at the time that VoLL was changed.

approach would be a variable cap. A single cap level (ie a reduced level of VoLL) is a simple and effective method.

Retrospectivity over a reasonably long accumulation period requires a "dynamic scaling" type approach to prevent post-settlement revision of prices. The effect of dynamic scaling, however, is simply to apply a variable weekly cumulative price cap, based on the cumulative (capped) price for the week that has just "dropped out" of the rolling accumulation window.

To see this, suppose that the accumulation period is 13 weeks, and the cumulative price cap is $100/kW. Now suppose that the most recent week has been scaled back so that the 13-week cumulative price is $100/kW. Suppose also that the cumulative scaled price for the 1st week of that accumulation period is just $2/kW. Thus, once a further week goes by, a new week of prices enters the accumulation period and the week with $2/kW cumulative price drops out. Therefore, the new week must be capped so that it does not exceed $2/kW to avoid breaching the $100/kW cap. This feature of "looking back" 13 weeks appears to be fairly arbitrary.

This flaw will be most apparent where the bulk of the cumulative price is accounted for by a few consecutive weeks within the accumulation period, with other weeks having a generally low cumulative price – leading to low cumulative price caps for future weeks as the earlier weeks drop out of the accumulation period. Thus, a nested price cap approach will mitigate this to some extent by capping prices over that shorter period.

The *prospective* approach avoids the need for this dynamic scaling mechanism and its attendant flaws. On the other hand, it does mean that price caps are progressively introduced – perhaps unnecessarily - before the cumulative price cap is reached. Nevertheless, this gradualist approach to capping does in some ways seem preferable to the alternative "bang bang" approaches where the capping is either "fully-on" or "fully-off".

The prospective mechanisms allow prices to be calculated and published in real-time. They are also simpler to understand and model than the retrospective approaches. Whilst the example shown above has six "bands" for VoLL, this number could be reduced if there were a desire to further simplify the mechanism. In fact, the current CPT/APC mechanism is, in effect, a prospective price cap mechanism with only two VoLL bands: $10,000/MWh and $100/MWh[11]. Thus, the prospective price cap mechanism need not be significantly more complex than the current mechanism.

Conclusion

A cumulative price cap, enforced by a *prospective* and gradualist capping mechanism, creates greater certainty and hedgeability for participants and also ensures a smoother, gradualist application of the cap, rather than the "bang-bang" seen under a CPT-mechanism.

The *retrospective* approach, however, is complex, retrospective and somewhat arbitrary.

[11] Complicated, somewhat, by a $50/MWh off-peak "VoLL".

Changing Generation Compensation

Options

Generation compensation applies to "constrained-on" generating units: ie dispatched generators with offer prices (on dispatched price bands) higher than the capped or otherwise adjusted, spot price. Alternative options should look at reducing the amount of discretion in determining compensation inherent in the current mechanism, and eliminating the possibility of a de facto, unhedged, pay-at-bid market.

Compensation should be based on the actual financial loss suffered by the generator as a result of being constrained on and this must be specified mechanistically so as to minimise discretion.

To estimate this loss, it is necessary, firstly, to establish a "base point": ie the position that a generator would have been in had it not been constrained on. This should be based on the dispatch level of a generating unit, based on its actual dispatch offer, consistent with the capped price. So for example, if a unit offered minimum load at $30/MWh (say), but all other price bands were priced above the price cap, then the dispatch base point would be minimum load, and the compensation would be based on the financial loss arising from being dispatched above minimum load: ie the costs arising from the extra generation, minus the additional pool revenue (at the capped price)

The generator costs could be estimated based on:

- historical offer prices
- incremental costs[12]
- incremental costs plus an allowance for fixed costs; or
- average costs, based on an assumed capacity factor

Historical offer prices could be based on, say, average offer prices over the same season in the previous year. Because prices are defined over 10 price bands, some potentially complex averaging rules would be needed. Use of historical bids prevents generators from "ramping up" offer prices during the APC period.

Incremental costs would need to be estimated by an independent expert, based on factors such as fuel cost, heat rate, variable o&m costs and so on.

Because generators expect to recover a portion of their fixed costs during high price periods, an allowance could be made in the generation compensation process rather than through the price cap. This could, potentially, allows different treatment of different plant types (eg peaking vs baseload).

Average costs are calculated as the variable costs, plus the annualised capital costs divided by the expected annual hours of dispatch. This is the approach that has been

[12] These could include start up costs, if the dispatch base point was zero.

taken, for example, by an independent expert for determining a "fair price" for directions compensation[13]

Another option to consider is to provide compensation to constrained-off demand-side bidders (DSBs): ie those who are dispatched to reduce load, but whose bid prices are higher than the (capped) spot price. Without such compensation, DSBs will simply withdraw their bids, possibly leading to greater amounts of (involuntary) load shedding than would otherwise be required.

There is a well known gaming problem with making constrained-off payments to DSBs. A DSB can bid a portion of its load as price-sensitive at high spot prices, even though in reality it has no intention of consuming this load. It is then dispatched to reduce load to the level that it would have consumed anyway, and paid "constrained-off" compensation, based on the difference between its high bid price and the capped spot price.

The way to prevent this gaming would be to ensure that the bidding during the capped period reflected bidding behaviour during the uncapped period. The alternative is to pay compensation based on the assessed "true value" of the dispatched demand reduction (analogous to paying a generator based on variable cost) but this is unlikely to be practicable.

Evaluation

It is important to ensure that genuinely constrained-on generation is compensated, since it will otherwise simply make itself unavailable for dispatch[14]. However, it need not be paid significantly more than its incremental costs to correct this problem. In fact, endeavouring specifically to provide for a contribution to capital costs probably does little to lessen the impact of the APC on generators, since any contribution will be small compared to the major potential gains or losses likely to accrue during extreme price periods, and APC periods should, in any case, only occur very infrequently.

Incremental costs, however, are not always straightforward to determine, particularly for peaking plant such as GTs, where significant costs are associated with start-up, particularly where numerous start-ups lead to the need for additional maintenance or even a shortening of asset life.

Thus, a proxy for variable costs may be historical bidding behaviour. However, in practice, many peakers may bid substantially above variable costs, in order to provide greater likelihood of a contribution to capital costs when dispatched.

Average costs in effect provide an allowance for some measure of fixed costs (eg one year's contribution). If the average were based on expected running hours in a normal year, then the unusually high level of running hours during abnormal conditions could lead to the generator substantially over-recovering its annual fixed costs. On the other

[13] NECG Independent Export Report for Directions of 11 and 12, Final Report under clause 3.15.7A of the National Electricity Code, November 2003

[14] In this case, it might be directed and become entitled to compensation for direction. The process for determining this also relies on significant discretion from the independent expert appointed.

hand, if the average is based on the actual running hours during the APC period, then this will not be known until the end of the abnormal period.. This could significantly delay settlements.

Thus, the best approach seems to be to compensate based on incremental costs. This should help ensure that generators make themselves available, whilst minimising the level of costs that feed into uplift.

Compensating constrained-off DSBs may also feed into uplift somewhat, but the amount is likely to be limited due to the relatively small volume of DSB in the market. Conditions for compensation, however, must be strict, such as a history of bidding in the market, and following dispatch instructions, during normal periods. DSBs should be notified in advance whether they will be eligible: if not, they can simply bid withdraw their bids.

The extra costs of compensating DSBs should easily be offset by the consequential reduction in prices and load shedding during abnormal periods.

Conclusion

Constrained-on generators should be compensated based on variable costs although these should be interpreted broadly to allow for start-up costs and so on.

Demands-side bidders should also be entitled to compensation, but only where they have a history of similar bidding and load management during normal market conditions.

6. Numerical Analysis

Background

It is always helpful to apply design ideas to real or simulated market data. Firstly, this proves whether the proposed method is properly defined and practically implementable. Secondly, strengths and weaknesses of a method may become apparent that were not anticipated from a purely analytical or qualitative assessment. Finally, the efficacy of the different methods in achieving the objectives may be compared.

Unfortunately (in relation to this report), the NEM has not seen any of the abnormal circumstances that an APC-mechanism is designed to address. However, it has seen some fairly extreme price outcomes in both South Australia and Queensland. For this analysis, South Australian data has been used. Half-hourly data for calendar years 1999-2001 has been downloaded from the NEMMCO website.

Strawmen Modelled

An excel spreadsheet has been developed to model the following strawmen:

- the current CPT mechanism
- a CPT with a longer accumulation period
- a retrospective cumulative price cap
- nested retrospective cumulative price caps
- a prospective cumulative price cap

Each of these strawmen has been designed to cap the cumulative premium – using a strike price of $100/MWh – over a rolling 91 day accumulation period. The cap is set at $50/kW. This is probably much lower than the actual cap that would be used, but is chosen to test the models' effectiveness of capping the premia actually seen in SA.

Details of each strawman are given in the table below.

<table>
<tr><th>Strawman</th><th>Parameters</th></tr>
<tr><td>Current CPT mechanism</td><td>7 day accumulation period
Trigger level at $20/kW</td></tr>
<tr><td>Longer CPT mechanism</td><td>91 day accumulation period
Trigger level set at $50/kW</td></tr>
<tr><td>Retrospective Cumulative Price Cap</td><td>91 day accumulation period
Cap set at $50/kW
Scaling carried out each day</td></tr>
<tr><td>Nested Retro Cumulative Price Caps</td><td>Inner Cap
28 day accumulation period
Cap set at $20/kW

Outer Cap
91 day accumulation period
Cap set at $50/kW</td></tr>
<tr><td>Prospective Cumulative Price Cap</td><td><table>
<tr><td>Cum Price ($/kW)</i></td><td><i>VoLL($/MWh)</td></tr>
<tr><td><20</td><td>5000</td></tr>
<tr><td>Between 20 and 30</td><td>2000</td></tr>
<tr><td>Between 30 and 40</td><td>500</td></tr>
<tr><td>Between 40 and 50</td><td>200</td></tr>
<tr><td>Above 50</td><td>100</td></tr>
</table></td></tr>
</table>

Results

The results of the analysis are shown graphically in the Appendix.

Figure 1 shows the daily, uncapped, cumulative premia in SA over the period analysed

Figure 2 shows the rolling 91-day cumulative premia using the different CPT/APC strawmen.

Figure 3 shows the periods for which each strawman was actively capping or scaling back prices.

The table below shows the number of days that each strawman was active over the period and the average scaling factor: ie the amount by which the cumulative premium was reduced.

Strawman	# days active	Average scaling factor over active periods
Weekly CPT	37	7%
Longer CPT	268	1%
CPC	41	11%
Nested CPC	48	8%
Prospective CPC	129	49%

Note that the scaling factor for the CPT mechanisms is non-zero because in some cases, the APC-period commences part way through the day, so not all half-hours are scaled back to zero.

The Longer CPT is the most “intrusive” in the sense that it is active for long periods and has a very low scaling factor. The prospective CPC is also active more than the other strawmen, but has a higher scaling factor, demonstrating that much of the time the lower VoLL has little effect on cumulative premia.

Figure 2 shows that each of the strawmen was effective at capping the rolling 91-day premia at $50/kW, except for the current, weekly CPT, where the trigger level could be reduced further to achieve this.

An interesting feature of the extended CPT is that it actually reduced the rolling premia to zero for a period (from March to May 2000), as the APC is active from December 1999 through to May 2000 (see figure 3), much longer than any of the other strawmen. The reason for this is that the CPT mechanism is triggered by the cumulative premium of the *uncapped* prices, and these premia continue to accumulate even during an APC period. The other strawmen look at the cumulative premia from the *capped* prices.

On the other hand, the weekly CPT is the least active, but is still fairly effective at capping cumulative premia. This is perhaps because the price spikes were fairly short-lived, characteristic of “normal extremes” rather than a genuine abnormal period.

The (single) retrospective CPC is the only strawman to cap the rolling premia at exactly $50/kW, because it is specifically designed to do exactly that. The prospective CPC keeps rolling premia significantly below $50/kW, since VoLL begins to be reduced long before the CPC is reached. Again, this partly reflects the fact that the price spikes are fairly intermittent. The CPC is more likely to be reached during an abnormal periods where the price spikes occur over a sustained period.

Conclusions

It is difficult to draw robust conclusions from this analysis, mainly because the price history used does not contain any genuine abnormal conditions.

However, it does appear to demonstrate the risk that the longer CPT could be active for extended periods of time. It also shows that the current CPT does not necessarily cap cumulative premia/prices over longer periods.

7. Conclusions

Objectives of an Administered Price Capping Mechanism

1. An APC mechanism should cap cumulative spot prices – or premia above a given strike price – during "abnormal" periods in the market caused by unexpected FM-type events, whilst having minimal impact on the market outside these periods.

2. The APC mechanisms should as far as possible also have the characteristics of being:

   - *hedgeable*: costs are passed through in spot prices, not uplift
   - *real-time*: prices should be published in real-time or as soon as possible after trading;
   - *mechanistic*: the APC rules should limit the discretion available to NEMMCO or other parties;
   - *simple*: easy to understand and model.

3. The APC should not aim to mitigate value impacts during short-lived transmission problems: this should be addressed through the market suspension provisions.

Evaluation of the Current APC-mechanism

1. The current mechanism does not necessarily cap cumulative spot prices, as prices may track below the CPT-trigger, or the APC period may be triggered and then "reset" repeatedly over the duration of a single "abnormal" period.

2. Due to its short accumulation period and relatively low CPT level, the current mechanism is liable to be triggered during "extreme normal" conditions, such as during a spell of hot weather and could therefore adversely affect the returns available to peaking plant.

3. The provisions for compensating constrained-on generators are unclear, provide substantial discretion, and could give rise to a de facto pay-at-bid market, passing substantial, unhedged costs through to retailers.

4. The current mechanism does not provide compensation for "constrained-off" demand-side bidders, removing the incentive for them to bid during APC-periods.

Changing the APC-mechanism

Possible changes to the CPT mechanism are listed below. Each change has the potential to improve the mechanism in relation the objectives and desirable characteristics described in this report. The suggested changes are not mutually exclusive and could be applied in combination.

1. Increase the accumulation period for the CPT. This would reduce the probability of improper triggering during normal periods and of multiple triggering during abnormal periods. On the other hand, this could cause the APC period to continue for some time after the abnormal conditions had ended.

2. Introduce a “prospective cumulative price cap”, by which VoLL is progressively reduced as a rolling cumulative price cap is reached. This would ensure that cumulative prices do not exceed a specified amount over an abnormal period. It would also mean that prices are reduced *during* the abnormal period rather than (potentially) only after it has finished, which should better protect participants whose hedge cover is reduced by the abnormal events. The more VoLL bands used, the smoother the transition from the normal VoLL price cap to the lowest price cap, but the more complex the mechanism would be to model and operate.

3. Amend and clarify the provisions for compensating constrained-on generators such that generators are only entitled to be compensated based on actual additional costs incurred as a result of being constrained on relative to the capped prices: ie dispatched at a level higher than that implied by their dispatch offer and the capped pool price. This would reduce discretion and reduce the potential for large amounts of uplift due to generator “profiteering” during the abnormal period, whilst ensuring that high-cost generators are adequately compensated for making themselves available for dispatch at the capped pool price.

4. Introduce provisions to compensate “constrained-off” demand-side bidders, subject to strict conditions to ensure such bids are genuine. This would improve incentives for voluntary demand side management, and reduce the extent of involuntary load shedding.

5. Introduce a “multivariate” trigger for identifying the onset of an abnormal period alongside a price-driven trigger. The multivariate trigger could include a list of “FM events”, a threshold for abnormal levels of non-price effects such as load-shedding, or a trigger threshold for changes of generator availability from PASA forecasts. This would lead to a faster triggering of the APC period where the identified FM events or conditions occur and therefore reduce the level of cumulative prices.

6. Base the APC-mechanism on capping cumulative premia – above a specified strike price – rather than cumulative prices. This would better delineate between abnormal conditions – generally characterised by extreme price volatility – and a general rise in prices.

APPENDIX: Charts showing effect of alternative models on SA Prices: 1999-2001

Figure 1: Daily Cumulative Premium

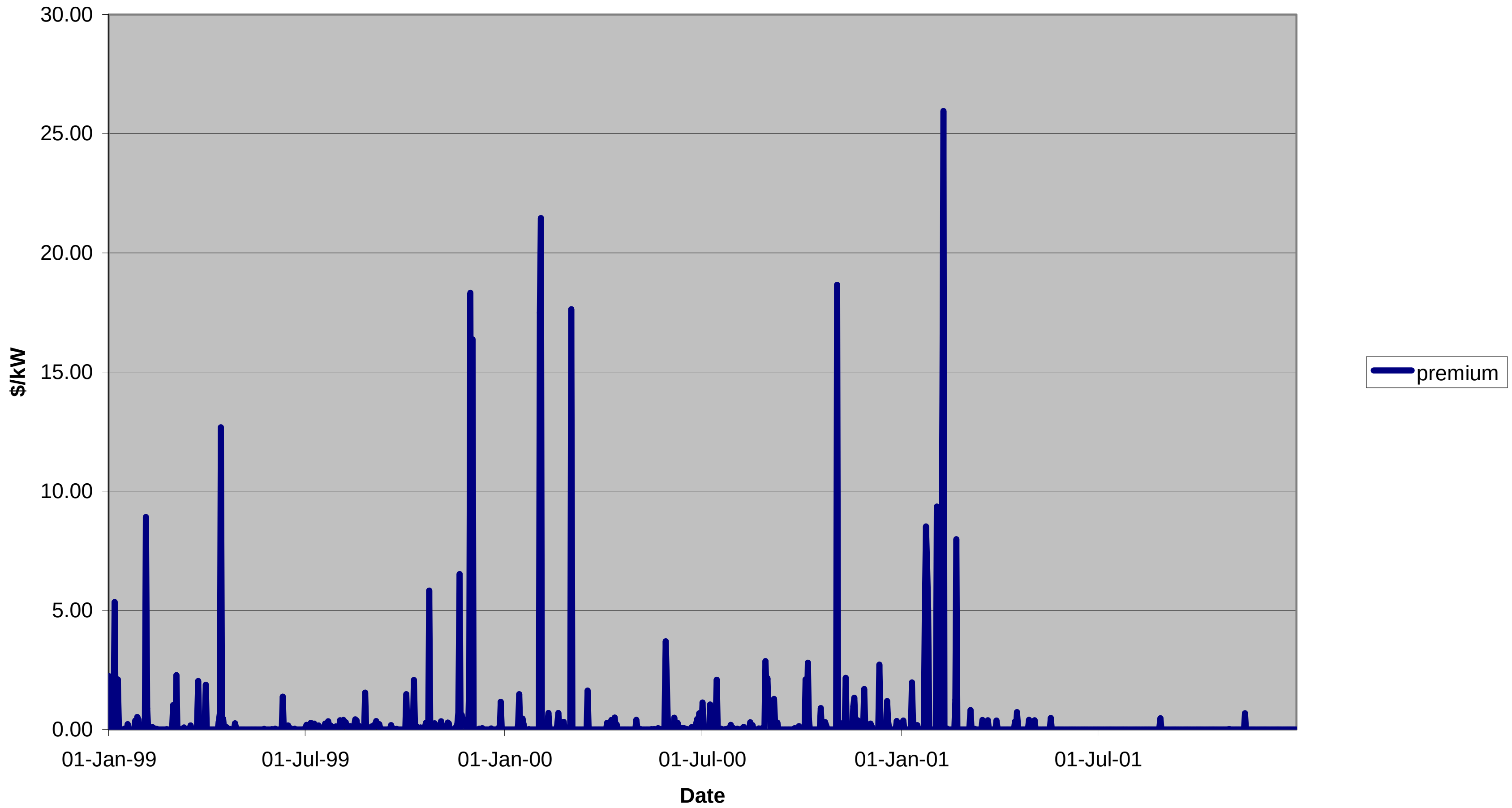


Figure 2: Rolling Cumulative Premia

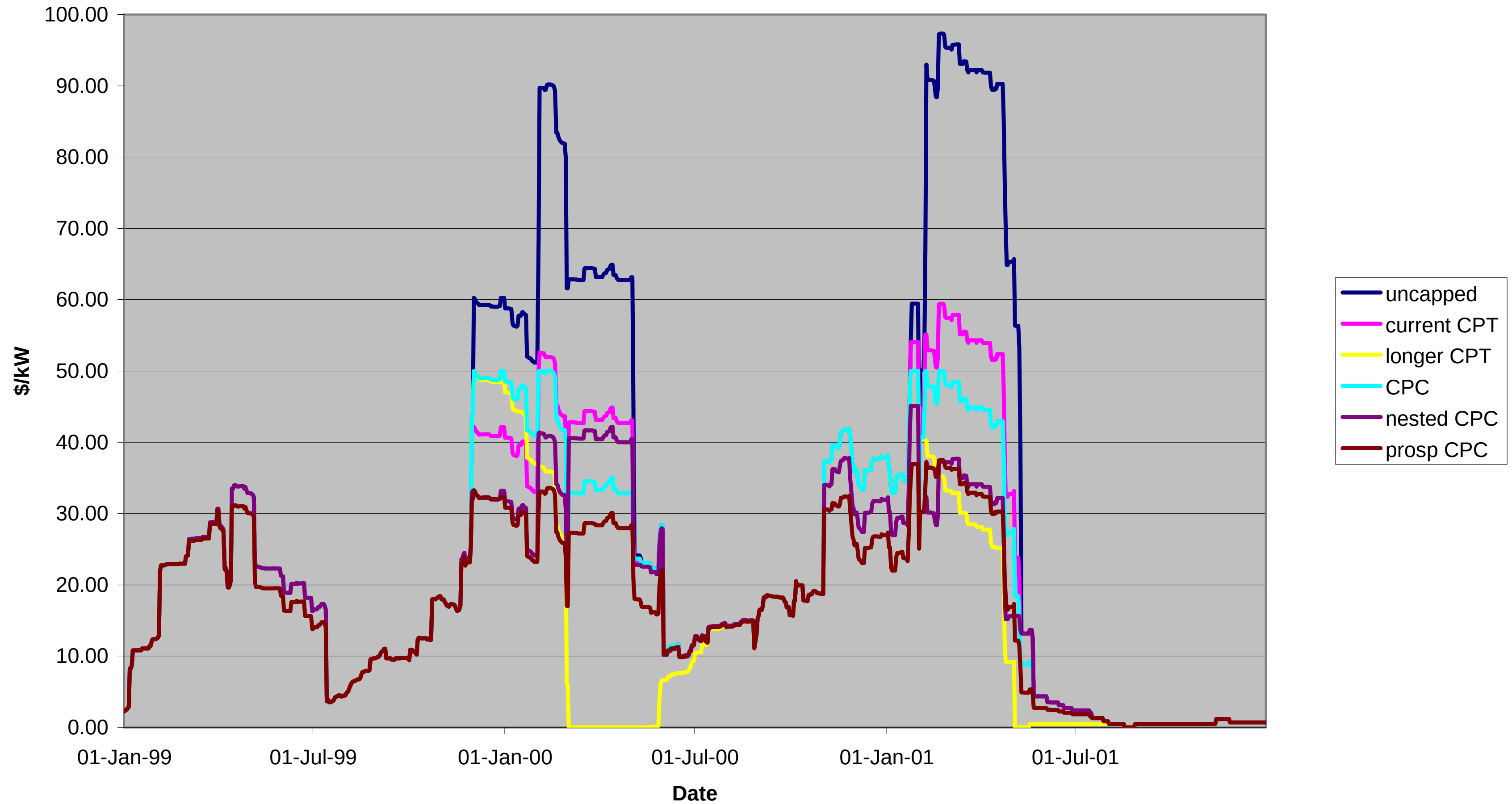
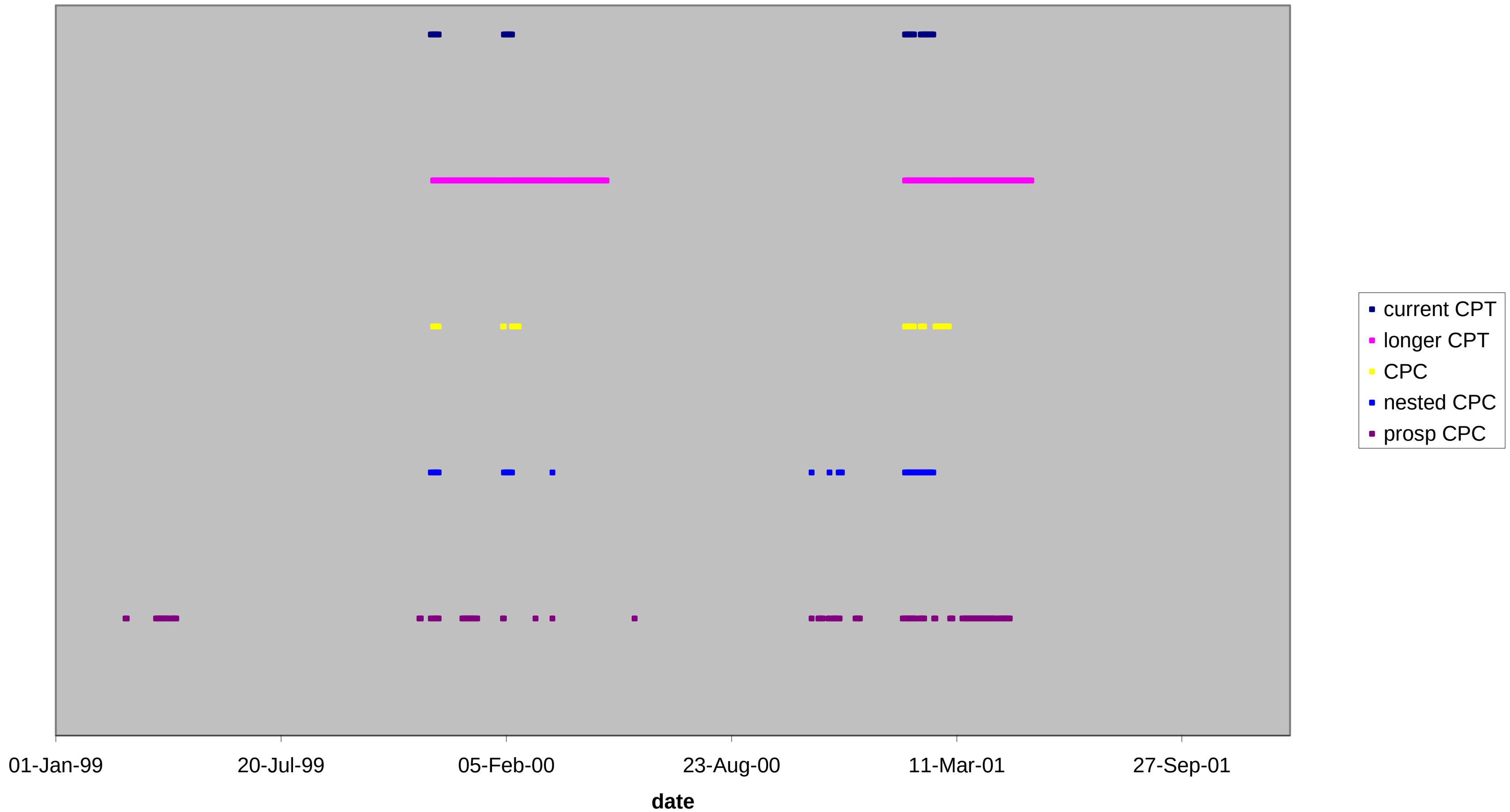


Figure 3: Capping Activity



Energy Retailers Association of Australia

Literature Review

International Market Mechanisms

2 May 2006

This report contains 55 pages

Contents

1 Background and Disclaimer

1.1 Background

The AEMC has requested the Reliability Panel (the Panel) undertake a comprehensive and integrated review relating to (amongst other things) the Value of Lost Load (VoLL), market floor price and cumulative price threshold (CPT). As part of this process, the Panel proposes to publish an Issues Paper by 11 May 2006, and allow for submissions from interested parties by 30 June 2006.

In order to assist in the development of its views on this component of the Panel's Issues Paper, the Energy Retailers Association of Australia (ERAA) requested that Network Advisory Services undertake a high level literature review on:

- What mechanisms are used by other electricity markets to signal supply and demand side investment, including identifying what factors drive supply of generation;
- How effective these mechanisms are at delivering system reliability and sufficient reserve capability;
- How these mechanisms impact on financial market liquidity and availability of hedge contracts from generators;
- How reliability standards are determined in other electricity markets compared to the National Electricity Market (NEM); and
- How the markets in which these mechanisms operate are different from the NEM and whether these mechanisms would be compatible with the current NEM design.

The report provides the outcomes of our review:

- **Sections 2 - 5** respond to the above key issues directly for the agreed markets of New England, Western Australia, Great Britain (England, Wales and Scotland), Nord Pool and Chile. As agreed with the ERAA, the report primarily focuses on supply adequacy (generation) rather than demand-side measures or the management of network capacity or network reliability;
- **Section 6** identifies the key mechanisms from the agreed markets and assesses their compatibility with the NEM;
- **Appendix A** provides a high-level comparison of the markets reviewed in terms of the questions posed by the ERAA;
- Appendix B provides detail of the individual system reliability obligations of the Nord Pool participant countries; and
- **Appendix C** contains a list of primary data that would allow the ERAA to undertake a more in-depth analysis of particular areas identified in our high level review.

1.2 Approach

In undertaking this literature review, we:

- Undertook an internet search of publicly available material, limiting the scope of published material to the most current (2002 onwards) unless a document was of particular relevance;

- Discussed our preliminary findings with participants in each of the markets covered in this Report, to be sure that the literature review was correct; and

- Held discussions with TRUenergy, AGL, Energex and Ergon Energy Retail in relation to the applicability of international market mechanisms in the NEM.

1.3 Disclaimer

The contents of this report pertain solely to the facts, circumstances and assumptions which were provided to Network Advisory Services during discussions with ERAA and its members, with participants in international markets and in written materials provided by ERAA and international market participants in the course of consultations. Our conclusions may not be valid if there is any change in those facts, circumstances or assumptions. Accordingly, while we believe that the statements made in this report are accurate, no warranty of accuracy or reliability is given.

Neither Network Advisory Services nor any employee of Network Advisory Services takes responsibility arising in any way whatsoever to any person (other than the ERAA) in respect of this advice, for any errors or omissions herein, arising through negligence or otherwise however caused. This report is not to be used for any purpose than those specified herein, nor may extracts or quotations be made without our express approval.

2 What mechanisms signal supply and demand side investment?

2.1 The 'Investment Envelope'

The AEMC in its Terms of Reference to the Panel identifies VoLL, the market price floor and the CPT arrangements as providing the *"key price envelope"* for the delivery of reliability and the signalling of demand and supply-side investment in the NEM.

This section identifies the mechanisms that exist in other electricity markets which in combination, provide the key parameters for signalling new investment of a nature and of a type required to support reliability and reserve capability. As agreed with the ERAA, the report focuses primarily on those mechanisms intended to signal the delivery of new supply-side investment.

The subsequent sections of the report explore the effectiveness of these 'investment envelopes' in delivering investment outcomes and their possible application to the NEM.

2.2 New England

Market Characteristics

Installed Capacity	32,863 MW
Energy Consumption	132,522 GWh
Peak Load	25,384 MW
Generation Mix	Gas 30%; Nuclear 28%; Oil/Gas 13%; Coal 12%; other 17%.

Source: ISO New England, *2004 Annual Markets Report*, www.iso-ne.com

Market design

Under the New England Standard Market Design (SMD), new investment is signalled through a combination of:

- An energy market; and
- A capacity market; and
- Bilateral and forward markets.

The energy market prices energy both in real time, establishing market clearing prices on a five minute basis using locational marginal pricing, and on a day ahead basis. The market operates via the Independent System Operator (ISO), which commits and dispatches units in economic merit order (ie the generators with the lowest-price offers are committed and dispatched first)[1].

Operation of the energy market is supported by the procurement of ancillary services. Although aimed at ensuring that the energy market's prevailing technical requirements are satisfied, these ancillary services do not strictly fall within the 'envelope' of market mechanisms intended to signal investment and therefore are not examined in detail.

Research suggests that while competition among generators in New England usually drives generation price offers down to short run marginal cost, most generators earn revenues through the energy market in excess of their short run variable costs for fuel and other operating expenses, allowing them to recover capital costs[2]. This is because market clearing prices are based on the last generating unit needed to meet demand. Despite this, there is considerable evidence that these signals have not been sufficient to induce sufficient capacity to enter the market (see section 3.1).

The installed capacity market (ICAP) in New England has been the subject of considerable and lengthy debate. Although New England has had a capacity ticket mechanism for many years, its design is generally thought to be flawed as a result of its:

- Failure to signal the development and delivery of capacity where needed as a result of all capacity being treated as 'equal' regardless of its location. That is, the ICAP fails to recognise that transmission constraints caused generation within congested areas to be of greater value than generation capacity located elsewhere[3] and

- Independence from the energy market (i.e. in terms of payment). This has the potential to manifest, for example, through the level of availability (or lack thereof) of capacity resources during periods of system stress/high prices and incentives to raise prices in the energy market without an accompanying reduction in the level of capacity payments received.

For example, 2004 saw a noticeable increase in the number of generation units choosing to 'delist' from participation in the capacity market. Although recognised at the time as a response to prices in the capacity market and the ability to earn revenues through alternative use of the capacity, a significant proportion of the 'delistings' occurred in historically constrained areas where they were most needed for reliability[4].

These "flaws" have meant that the market design has provided insufficient investment signals for ensuring long-term reliability of supply[5].

The design of a revised capacity mechanism for the SMD has been occurring over several years, with the latest permutation being a concept of a forward capacity auction (FCM)[6].

[1] ISO New England, *Wholesale Energy Market Course (WEM 101)*, www.iso-ne.com.
[2] ISO New England, *Wholesale Markets Plan*, www.iso-ne.com, 2006, p 6.
[3] http://energylegalblog.com/archive/2005/06/29/46.aspx.
[4] ISO New England, 2004 Annual Markets Report, www.iso-ne.com, p58.
[5] ISO New England, *Wholesale Markets Plan*, www.iso-ne.com, 2006, p 4.

The FCM, submitted to the FERC in April 2006, establishes an annual auction-based market where:

- The "product" is a MW of deliverable capacity with a future supply commitment three years in advance;

- The amount of capacity that the ISO procures in the auction is 100 percent of the forecast installed capacity requirement for the commitment period;

- Capacity may be supplied by many types of Capacity Resources, including traditional generating plants (established and new), intermittent resources (e.g., wind and hydro), and demand-side response resources located in New England, as well as imports of capacity resources from outside New England. Capacity zones are determined by the ISO prior to the auction, based on an identification of transmission limits that may bind. This 'locational component' is intended to assist to value capacity appropriately in constrained areas[7]; and

- A 'deduction' is included from the monthly capacity payment for 'peak energy rent' – this is effectively determined by calculating the difference between the real time energy price and a strike price derived from the incremental hypothetical cost of a proxy unit. The deduction acts as a hedge for load against price spikes in the energy market and is intended to provide a disincentive from suppliers exercising market power in the energy market[8]. Penalties also exist for poorly performing capacity resources and those that do not demonstrate a high level of 'availability'.

The auction itself is a "descending clock auction", whereby the ISO announces a starting price - twice the Cost of New Entry (CONE) - set at $7.50/kw for the first auction[9].

Bidders are given time to decide how many MWs to offer at the stated auction price. Following the end of each bidding round, the ISO adds up the quantity of resources offered at the stated price and if the number of MWs offered is more than the number of MWs required, the ISO lowers the price for the following round - i.e., the "clock ticks down" and bidders again decide how much to offer at the lower price. When the total amount of MWs submitted equals the total amount of MWs required, the auction closes and the "winners" of the auction process are declared. Bidders must submit bids in every round and the number of MWs they submit in a round may never be larger than the number of MWs they submitted in a previous round.

The last round of the auction sets the Capacity Clearing Price, which is the price received by all successful Capacity Resources and is, in most instances, the price that will be incorporated into the next auction's starting price[10].

---

[6] FERC, *Explanatory Statement In Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues*, Devon Power LLC, et al., 2006 Docket Nos. ER03-563-000, -030, and -055. This is an abbreviated list of the features of the LICAP, directed at investment signalling only.

[7] ibid

[8] ibid

[9] ibid

The FCM been designed specifically to counteract the lack of signalling in the energy market to new investors. The key investment signalling design features of the FCM are:

- An auction format to derive competitive prices approximating the cost of new entry;
- Forward procurement of capacity resources, which provides opportunities for new entry to participate in the market and secure returns; and
- Market power mitigation rules[11].

On the first feature, because competing capacity resource suppliers determine the prices, the compensation received by capacity resources will over time approximate the cost of new entry. This is intended to appropriately compensate existing generators needed for reliability and attract and retain new entry. Additionally, because all generators receive the same auction clearing price, the mechanism rewards the lowest cost plant for the capacity sought – whether baseload, intermediate, or peaking[12].

On the second feature, if a new entrant is successful in the auction, it has more than three years to build the necessary infrastructure needed to fulfil its capacity obligation. This is considered by the New England ISO to be ample time to plan and construct additional generation capacity.

On the third feature, the New England regime builds in a number of elements to prevent market failures associated with high concentrations of market power, whether held by buyers or sellers:

- The auction rules curb incentives to manipulate the market and distort capacity prices - only specified types of bids can set the auction's clearing price paid to auction winners and incorporated into the successive auctions' CONE.
- Specific market rules, such as the Insufficient Competition Rule have been designed to address problems of market failure. The Insufficient Competition rule sets prices for capacity resources if the system (or zone) is short of capacity or if the total amount of new capacity bid is small. If the Insufficient Competition rule is triggered, then new capacity resources are paid the Capacity Clearing Price and existing capacity resources are paid the lower of the Capacity Clearing Price or 110% of the cost of new entry.
- There is provision for the ISO to review bids priced above or below specified price thresholds (which are tied to percentages of the cost of new entry).

---

[10] ibid
[11] ISO New England, *Wholesale Markets Plan*, www.iso-ne.com, 2006, p 6.
[12] ibid, section paraphrased.

- Capacity payments and the energy payments are netted off to directly target the motive on the part of generators to deliberately take action leading to market shortages[13].

The FERC has not approved the FCM and many aspects of the plan remain contested by a number of States in New England, although discussions with the ISO suggested that opposition to the FCM is 'political' and not based on any economic grounds. A decision on the FCM is due by 30 June 2006, with implementation potentially as early as October 2006.

2.3 Western Australia

Market Characteristics

Installed Capacity	3,150 MW
Energy Consumption	11,439 GWh
Peak Load	2,538 MW
Generation Mix	Gas 54%; Coal 42%; other 4%.

Source: Office of Energy, *Energy Western Australia 2003,* www.energy.wa.gov.au

Market Design

The Western Australian market is not yet fully operational but is expected to be so by 1 July 2006. New investment is designed to be signalled through a combination of the following mechanisms[14]:

- A short term energy market;
- Bilateral contracting markets;
- A reserve capacity mechanism; and
- A dispatch balancing process.

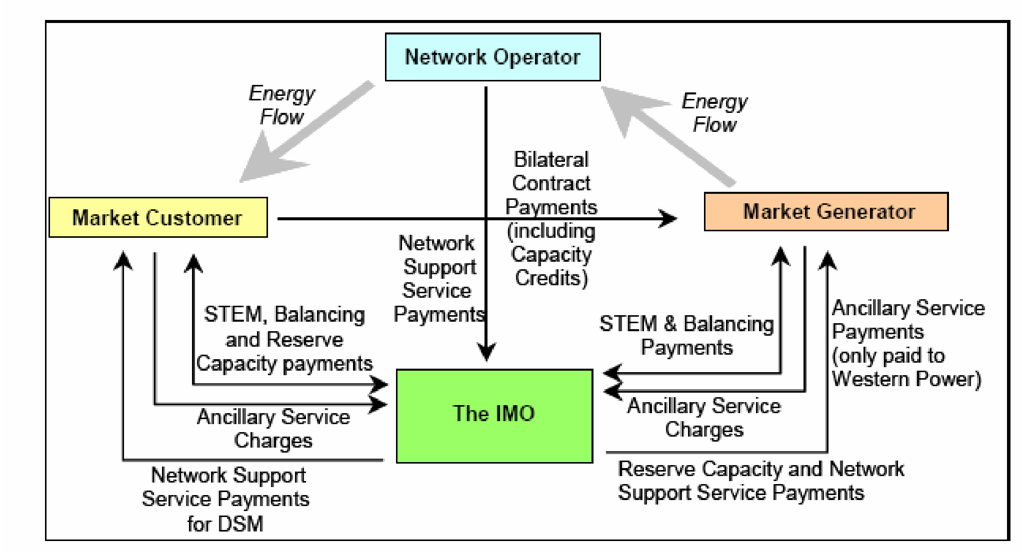
The interaction of these mechanisms and the major settlement cash flows between participants under the market design is illustrated below.

Diagram 1: Settlement Cash Flows with the Western Australian Market Design[15]

[13] Dr Steven Stoft, *Testimony on behalf of ISO New England on LICAP*, Submitted to FERC, Docket number ER-03-563-030, Direct August 2003.

[14] Independent Market Operator, *Wholesale Design and Market Summary*, www.imowa.com.au, October 2004.

[15] ibid



Each market mechanism is discussed in turn:

The Short Term Energy Market (STEM) is a daily forward market for energy that allows Market Participants to trade around their bilateral energy position, effectively producing a new net bilateral contract position. The market is operated and administered by the WA Independent Market Operator (IMO), which collects supply and demand price curves from Market Participants once a week to apply for the next week. Different supply and demand curves can be specified for each half hour Trading Interval[16].

Each day, the IMO will collect half hour Bilateral Schedule data from Market Participants, and use these and the weekly supply and demand curves to define STEM offers and STEM bids relative to the contract position for each Trading Interval. A STEM Offer is an offer to increase the net supply of energy beyond the Bilateral Schedule position, while a STEM Bid is a bid to decrease the net supply of energy relative to that position. A STEM auction will be run for each Trading Interval of the next trading day, determining a STEM clearing price and clearing quantities. The combined bilateral and STEM position of a Market Participant describes its net contract position[17].

Participation in the STEM is open to all Market Participants, but is not compulsory.

Bilateral trades of energy and capacity occur between Market Participants and the market has no interest in how these trades are formed. However, Market Participants will be required to submit Bilateral Scheduled data pertaining to bilateral energy transactions to the IMO each day so that the transactions can be physically scheduled.

The primary role of the Reserve Capacity Mechanism is to ensure that there is adequate capacity available each year to meet system peak demand plus a reserve margin[18]. It should

[16] ibid
[17] ibid
[18] ibid

be noted that the reserve capacity model has been developed in direct response to concerns regarding the timely commissioning of capacity resulting from the "energy island" characteristics of Western Australia[19].

The annual Reserve Capacity Requirements are based on a Statement of Opportunities Report that considers the capacity requirements of the system for the next 10 years. Each Market Customer is allocated a share of the Reserve Capacity Requirement, called its Individual Reserve Capacity Requirement, and is required to secure "Capacity Credits" to cover that requirement[20]. These Individual Reserve Capacity Requirements are both set annually and adjusted monthly[21].

The IMO assigns Capacity Credits to suppliers of registered capacity, where the suppliers have the choice of trading Capacity Credits bilaterally with Market Customers, or offering them to the IMO in an auction. The Capacity Credits the IMO procures at auction will be used to cover the remaining requirements of Market Customers.

Suppliers issued with Capacity Credits will, amongst other requirements, be obliged to make that capacity available to the market and to participate in centralised outage planning. Market Customers who do not procure sufficient Capacity Credits bilaterally will be required to fund capacity procured through the Reserve Capacity auction.

Providers of Capacity Credits who fail to meet the obligations of Capacity Credits will have to pay a refund that reflects a measure of the value to the system of the capacity not provided. Different refunds will apply at different times of day and at different times of year, with the aim of making refunds relatively small at times when the system has abundant capacity while making them quite high at times when non-compliance creates a high risk of load curtailment. While the basic refund will be determined for each Trading Interval, limits will be imposed on the total refund required in each Trading Day, in each of three seasons, and over the year.

These refunds will be rebated to all Market Customers who have either secured Capacity Credits through bilateral trade or from the IMO. These rebates will not just be focused on those funding the auction, as only a subset of Capacity Credits will be traded through the auction, and in some years there may not need to be an auction if retailers hold adequate Capacity Credits[22]. If an over-capacity situation were to arise, then the cost of the over supplied capacity will be shared across all Market Customers, irrespective of whether they hold Capacity Credits.

Diagram 2 illustrates the impact of the Reserve Capacity Requirements and Capacity Credits on trading and settlement.

---

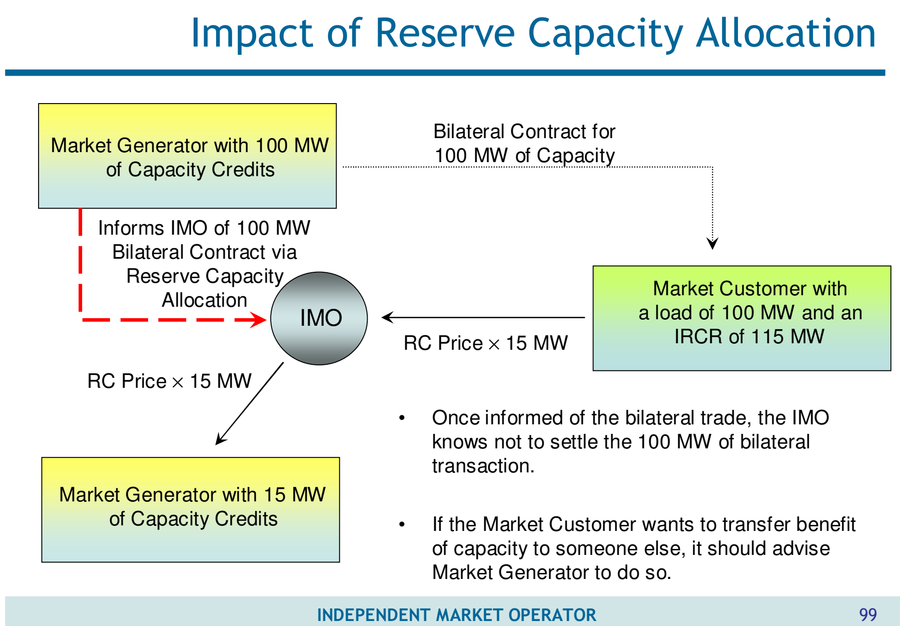
[19] Office of Energy, Government of Western Australia, presentation at www.eriu.energy.wa.gov.au/cproot/710/3912/6th%20Energy%20Conference%20-%20Perth.pdf , 2004

[20] Independent Market Operator, *Wholesale Design and Market Summary*, www.imowa.com.au, October 2004

[21] Independent Market Operator, Reserve Capacity and Network Control Service, presentation at http://www.imowa.com.au/Market_Training.htm, 2006

[22] Independent Market Operator, *Wholesale Design and Market Summary*, www.imowa.com.au, October 2004

Diagram 2: Impact of Reserve Capacity Allocation[23]



Reserve Capacity auctions are held 2 years before capacity is required. The idea of holding Reserve Capacity auctions 2 years before the capacity is required is to allow time for peaking plant to enter the market based solely on the auction revenue.

Base load plant is unlikely to be able to profitably enter the market based solely on Reserve Capacity Revenues, so this type of plant is more likely to trade Capacity Credits bilaterally. However, should base load plant have any spare capacity there is nothing stopping that spare capacity being offered into the auction to gain additional revenue[24].

For the dispatch/balancing process, market generators other than Western Power will be required to provide schedules called Resource Plans to the IMO that cover their net contract position. These schedules include the output of each generator in each Trading Interval and the total load to be supplied by a participant. System Management (responsible for operating the power system to maintain security and reliability), will schedule Western Power resources around those schedules, but it may issue dispatch instructions to other Market Generators if it cannot otherwise maintain security and reliability, or if it would have to use expensive liquid fuelled plant while other Market Generators have non-liquid fuel capacity available. After the Trading Day, the IMO will determine "administrative" balancing prices to apply for unscheduled deviations from the schedules, with those IPPs who were given Dispatch Instructions being settled on a pay-as-bid basis.

[23] Independent Market Operator, Reserve Capacity and Network Control Service, presentation at http://www.imowa.com.au/Market_Training.htm, 2006

[24] Independent Market Operator, *Wholesale Design and Market Summary*, www.imowa.com.au, October 2004

The energy market's operation will supported by ancillary services provided by Western Power. The requirements for each ancillary service will be proposed by System Management, but must be approved by the IMO. Although aimed at ensuring that the energy market's prevailing technical requirements are satisfied, these ancillary services do not strictly fall within the 'envelope' of market mechanisms intended to signal investment and therefore are not examined in detail.

The market makes use of a number of parameters, the value of which will materially change the cost and benefits of participating in the market. The IMO is proposing the following price caps based on principles established in the market rules:

- The Maximum Reserve Capacity Price - $150,000/MW (a minimum of 0 is assumed);
- The Maximum STEM Price - $150/MWh;
- The Alternative Maximum STEM Price, which exceeds the Maximum STEM Price and which will apply for offers pertaining to very expensive fuels, such as diesel; and
- The Maximum Shut Down Price, which defines the maximum compensation to be paid to a Market Participant if System Management requests an unscheduled shut down of the facility - $385/MWh.

These limits define the most extreme prices that participants can bid and offer as well as the most extreme market clearing prices that can occur. The Alternative Maximum STEM Price will be updated monthly based on changes in oil prices, while the Maximum STEM Price and the Minimum STEM Price will be adjusted automatically for inflation on an annual basis. The IMO will review all the price caps annually and if, after consultation with industry, it believes changes beyond the automatic changes are required, it will submit proposed new values to the Economic Regulation Authority for approval. The Economic Regulation Authority will approve these limits based on whether or not the IMO has set values in a manner consistent with requirements specified in the Market Rules.

2.4 Great Britain

Market Characteristics

Installed Capacity	71,446 MW
Energy Consumption	317,487 GWh
Peak Load	61,013 MW
Generation Mix	Gas 40%; Coal 33%; Nuclear 19%; Imports 2.5% other 5%.

Source: *Digest of Energy Statistics, 2005*, www.dti.gov.uk

Market Design

The wholesale electricity market in Great Britain (England, Wales and Scotland) is based on voluntary bilateral trading arrangements between generators, customers and traders. New investment is designed to be signalled through a combination of:

- Forward and futures contract markets;
- Power exchanges; and
- A compulsory imbalance settlement process.

The forward and futures contract market generally operates from a year or more ahead of real time up until 24 hours ahead of real time. The over-the-counter market offers a variety of contract types including annual, seasonal, quarterly and monthly contracts as well as non-standard 'tailored' contracts[25].

Trading on the Great Britain power exchange markets is able to extend out as far as the bi-lateral contract market. In practice, however, activity on the market focuses on the final 24 hours preceding market close. The exchanges are used by generators and customers to adjust their contractual positions closer to market operation. The power exchanges operate through standardised contracts, including spot and forward contracts[26]. Bilateral contracts and power exchange trading accounts for in excess of 98% of sales[27].

As system operator, National Grid (NGC) is responsible for physically balancing the market. The NGC provides a range of balancing services including:

- offers and bids in the 'Balancing Mechanism';
- contracted balancing services (effectively ancillary services), generally in option contract format, such as frequency response, reserve, reactive power and black start; and
- forward energy contracts[28].

Through the Balancing Mechanism market participants are able (but not required) to submit bids and offers to move away from their stated consumption or generation for specified volumes at a specified price. NGC uses these bids and offers to physically balance the system.

The Balancing Mechanism system's "sell and buy" figures reflect the costs incurred by the NGC in balancing the market. In general, generators which are under-contracted and

---

[25] Ofgem, *Ofgem's submission to the European Commission (DG TREN) Report*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG _DOCS/NATIONAL_REPORTS, 2005, p 30.
[26] ibid, p 31.
[27] Ofgem, *NETA – One Year On*, Ofgem fact sheet 16, March 2002. Note that the information provided in this fact sheet may have changed with Scotland entering the market.
[28] Ofgem, *Ofgem's submission to the European Commission (DG TREN) Report*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG _DOCS/NATIONAL_REPORTS, 2005, p 33.

therefore 'spill' electricity on to the system[29], can expect to receive a lower price for their electricity than if they had resolved their imbalance in forward markets. Similarly, suppliers which remain under-contracted as the balancing mechanism opens, thereby potentially imposing balancing costs, can similarly expect to be charged a higher price than if they had entered into contracts for their full requirements[30].

At settlement each market participant's position is assessed. The NGC calculates participants' imbalances, equalling the difference between its notified contract volume, including accepted bids and its loss-adjusted metered volume. Participants that are short, that is have consumed more electricity than notified, are required to pay the 'System Buy Price'. Participants that are long, that is have consumed less electricity than notified, are paid the 'System Sell Price'[31].

The wholesale market design does not include any explicit capacity mechanisms. The theory behind the current arrangements is that is allows the market to operate cleanly and effectively, as stated by Ofgem (2005) which noted:

> *The contractual freedom and bilateral pricing associated with the current trading arrangements ensures that prices are broadly cost-reflective as generators seek out purchasers for their power and suppliers and customers seek the most competitive terms from generators. It is Ofgem's view that the market signals provided by these cost reflective prices produce appropriate indications as to the needs for investment*[32].

Accordingly, supply side investment is principally signalled through prices in the forward and futures contract market and the power exchanges.

The balancing and settlement mechanism operates to encourage participants to balance their physical and contractual positions. The volume traded through the Balancing Mechanism represents only a small percentage of total demand. As such this mechanism operates more as a short-term adjustment tool rather than a long-term investment signal.

---

[29] potentially imposing balancing costs on the system operators

[30] Ofgem, *Ofgem's submission to the European Commission (DG TREN) Report*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG _DOCS/NATIONAL_REPORTS, 2005, p 21.

[31] Ofgem, *Ofgem's submission to the European Commission (DG TREN) Report*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG _DOCS/NATIONAL_REPORTS, 2005, p 21.

[32] ibid, p 85.

2.5 Nord Pool

Market Characteristics

Installed Capacity	90,876 MW
Energy Consumption	399,500 GWh
Peak Load	67,791 MW
Generation Mix	Hydro 49.1%; Nuclear 25%; Other thermal 17.8%; Renewable 8.1%.

Source: Nordel, *Annual Statistics*, www.nordel.org

Market Design

Nord Pool operates a number of markets for electricity bringing together producers and consumers from Sweden, Norway, Finland and Denmark. New investment is signalled through a combination of:

- A day-ahead spot market (Elspot);
- A intra-day trading market (Elbas);
- A financial market; and
- Separate real-time balancing mechanisms by individual member countries within Nord Pool.

Elspot is a voluntary power exchange and is both an energy and transmission capacity market, with transmission capacity implicitly auctioned through the spot market process. The transmission side of the market operates by:

- Transmission system operators in the different areas agreeing the amount of available capacity in the preceding day;
- The lowest transmission capacity in each direction being allocated to the spot market and its 'firmness' guaranteed by the transmission system operator; and
- Nord Pool making the capacity available on the spot market for the following 24 hours[33].

The energy side of the market is divided into separate bidding areas in order to manage known transmission capacity limitations. The bidding procedure involves:

[33] Swedish Energy Markets Inspectorate, *Annual Report to the European Commission*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS, 2005, p 9.

- Participants submitting bids and offers to Nord Pool by 12 o'clock the day prior to operation. Participants with generators or consumption in separate bid areas must submit separate bids for each area;
- Nord Pool balancing supply and demand by the hour to calculate the 'system price' for each hour of the following day (this price assumes no constraints on the network);
- Constraints between areas based on contracted power flows;
    - if there are no constraints the system price becomes the market price for the whole system and Nord Pool can calculate the MW buy/sell contract for each period for each bidder;
    - if there are constraints, then Nord Pool has to calculate separate prices for each area by balancing the bids within each area. A generator with supply contracts in different areas that are out of balance with its generation within an area is assumed to sell the power due to be transferred across the constraint to the sub-pool where it generates at the sub-pool price and then to buy it from the other sub-pool at its pool price for delivery to the customer. The power flow across a constraint multiplied by the difference in prices between two zones creates a congestion rental which is credited to a transmission system operator;
- settlement based on prices in the different areas[34].

Nord Pool acts as the counter-party in all transactions but all trades are physically settled with the respective transmission system operator.

The Nord Pool intra day market – Elbas – operates within the time span between setting the Elspot price and the actual delivery hour of the concluded contract (up to 36 hours). The Elbas market allows participants to balance their contracts to manage their positions taking into account events after closure of the spot market[35].

Elbas opens at 3pm for trade for the following power exchange day and one hour power contracts are traded for every hour of the power exchange day continuing up until one hour prior to delivery. Similar to Elspot, Nord Pool acts as the counter party in all transactions but all trades are physically settled with the respective transmission system operator.

Nord Pool's financial market has a maximum trading horizon of four years[36] using the Elspot system price as the reference price for the financial market. The market offers a wide variety of financial products including:

- base load day and week futures (6 weeks ahead) contracts;

[34] Federal Energy Regulatory Commission, *Electricity Market Design and Structure*, Docket No. RM 01-12-00, ksgwww.harvard.edu/hepg/Papers/Henney_transco_FERC_sub_1-7-02.pdf, 2002, p 34.

[35] Nord Pool, *Continuous trading at Nord Pool Spot's Elbas market*, www.nordpool.com/nordpool/spot/index.html.

[36] Nord Pool, *Trade at Nord Pool's Financial Market*, www.nordpool.com/nordpool/financial/index.html

- base load for calendar month, quarter and year forward (from 7 weeks to 4 years ahead) contracts;
- contracts for difference (covers basis risk where system price does not equal individual area price);
- option contracts;
- electricity certificates (spot contract with physical delivery);
- European Union Allowances (physical forward contracts for EU emission trading scheme)[37].

Real-time balancing is the responsibility of member countries and occurs after the trading markets close. Information on trades is submitted to the transmission system operator for physical balancing of the system. All transmission system operators operate their own 'balancing market' to adjust for any imbalance between contract positions and actuals during the delivery hour and all operate with a minimum required operating reserve.

In Sweden[38], the transmission system operator (TSO) is able is able to increase or decrease production and/or demand, through power trading between 'balance providers' to achieve system balance. These balance providers, which are able to change production during the balance interval (60 minutes), can submit bids for upward or downward control to the TSO's balance centre no later than 30 minutes before the start of the hour. The bids specify a price and power quantity from which the system operator selects the bids in order of price. A common Nordic 'regulating market' has been established and unless there are special circumstances such as bottlenecks, the TSO has to accept the lowest bid within the entire Nordic area[39].

Sweden's TSO considers that its system responsibility role infers the right, in emergency situations, to order electricity producers to increase or decrease their level of production in order to assist in the balancing of the system. The TSO has purchased gas turbines with a combined output power of 400MW, and signed a long term agreements enabling it to utilise a further 800MW in emergency situations. These reserves are not to be used during the normal operation of the market[40].

Since 1999, special rules have also applied to the pricing of balance and regulating power during normal operation but where there is a shortage of electricity production in the Swedish system and imports are not sufficient to meet the load. These circumstances can arise where there are severe cold weather conditions. Under these circumstances the TSO can signal higher prices for balancing power[41].

---

[37] ibid.

[38] NAS has selected Sweden as an example of how the balancing market works.

[39] Swedish Energy Markets Inspectorate, *Annual Report to the European Commission*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS, 2005, p 9.

[40] Svenska Kraftnat, *The Swedish Electricity Market and the Role of Svenska Kraftnat*, www.svk.se/web/Page.aspx?id=5843, p 9.

[41] ibid, p 9.

Nord Pool's spot and financial markets signal supply and demand side investment through transparent pricing in its spot, and forward markets. While Nord Pool does not have any explicit capacity mechanism, the transmission system operators in each of the member countries do maintain operating reserves (including both generation and demand response).

The Elspot price operates as the reference price for the financial power market as well as the bilateral wholesale power market covering the region[42]. There is no price cap or floor on bids in the spot market, hence generators can price to a minimum of earn long run marginal cost and to recover capital during price peaks.

As noted above, the market is divided into separate bidding areas in order to manage transmission capacity limits. Where there are binding constraints on the transmission network, Nord Pool calculates separate prices for each area by balancing the bids within each area. This provides a sharper locational signal for investment in new capacity in those areas which experience higher prices.

It is understood that investment in peak generation has been a concern for Government over the past few years. A specific concern with the current spot market mechanism is the maintenance of a single price area for Sweden despite significant internal transmission constraints. This practice has sparked criticism that this has artificially reduced the price in southern Sweden and therefore dampened the signals to power companies to invest[43].

2.6 Chile

Market Characteristics

Installed Capacity	8,000 MW
Energy Consumption	34,000 MWh
Peak Load*	5,768 MW
Generation Mix	Hydro 59%; Gas 21%; Coal 11%; other 9%.

Source: *Strengthening Regulation in Chile: The Case of Network Industries*, www.oecd.org; *Restructuring the Electrical Industry: Chile's Experience*, www.lyd.com/english/noticias/restructuring .ppt

Market Design

The Chilean market comprises two interconnected electricity systems - the SIC system which supplies approximately 90% of customers and the SING system which covers the northern part of the country and supplies the mining region. There are separate wholesale markets for each system.

42 Nord Pool, *Trading and settlement at Nord Pool Spot's Elspot Market*, www.nordpool.com.

43 Power in Europe, *Nord Pool Market Review*, Issue 465-466, 19 December 2005, p 5.

Chile was the first to commence a reform program (in the early 1980's) and was for a long time regarded as a pioneer in electricity market design. New investment in the Chilean market is currently signalled through a combination of:

- A regulated spot market for sales from generators to other generators;
- A regulated node price for sales from generators to distribution/retail companies;
- An unregulated contract market for sales by generators to large customers; and
- A capacity payments mechanism.

The Chilean market is not price based, it is cost based.

On the first issue, regulated spot prices are set at each node of the interconnected system and are based on the weighted average of short run marginal costs of generation for the entire system optimized over a 12- or 48-month horizon (which accounts for reservoir levels, plant availability, thermal plant operating costs, new capacity and rationing). The marginal cost of the last generator required to balance supply and demand, taking in to account transmission constraints and losses, determines the spot price at each node[44]. Dispatch is undertaken on an economic merit order, pre-programmed basis for the entire system in hourly units[45].

The unregulated contract market allows larger customers to contract directly with generators. Large customers (consumption above 2 MWh) are able to enter into bilateral contracts with generators and negotiate a price other than the regulated price.

The regulated node price applies to customers which use less than 0.5MW per annum (generally residential and small commercial customers). Distribution companies are required to enter into long-term contracts with the generators, at a regulated price, for supply to their regulated consumers. Two prices are paid by the distribution companies – nodal prices for energy and nodal prices for peak capacity[46]. The regulated node energy price is calculated by adding up node spot price plus the cost of the transmission service. Node prices are adjusted every six months using indexation formulas with pre-defined variable ranges. Forward contract prices that a generation entity can charge distribution companies are constrained by a requirement that they be no higher than 105% and no lower than 95% of the prices charged to large industrial customers who have directly negotiated prices with the generators[47].

The capacity payment mechanism in Chile provides payment to generators contributing with capacity in the yearly peak demand period (May - September), with payment depending on availability, time to start and time to full load. Capacity charges reflect the annual marginal

---

[44] Arellano, M., _Diagnosing and Mitigating Market Power in Chile's Electricity Industry_, http://www.web.mit.edu/ceepr/www/2003-010.pdf, 2003, p11-12.
[45] Ibid.
[46] Vignolo, M., _The New Electricity Supply Industry in Argentina and Chile_, www.iie.fing.edu.uy/investigacion/grupos/syspot/Argch_reg.pdf, September 2002. p 18.
[47] Arellano, M., _Diagnosing and Mitigating Market Power in Chile's Electricity Industry_, http://www.web.mit.edu/ceepr/www/2003-010.pdf, 2003, p 12.

cost of increasing system capacity assuming a specified reserve margin and reflect the capital and operating costs including a 10% return of the newest technology on the system adjusted by a capacity penalisation factor[48] - fixed at 5.25 US$/kW/month[49]. In October 2001, the capacity payments comprised approximately 20% of the energy final price[50].
Regulated customers therefore pay the regulated nodal spot price, plus regulated capacity payments. Non-regulated customers directly negotiated prices.

The primary investment signalling mechanism in Chile has been the regulated spot price and the non-market capacity payment. The regulated spot market allows most generators to recover in excess of their short run marginal costs as the spot price is based on the marginal costs of the last generating unit required to balance supply and demand.

In addition to energy prices, the capacity payments signal investment directly by providing income to generators which in addition to income from the energy market, is established. This capacity payment encourages investments by increasing and stabilizing the volatile income of generators[51].

[48] Pollitt, M., _Electricity Reform in Chile – Lessons for Developing Countries_, www.mit.edu/ceepr/www/2004-016.pdf, 2005, p 5.
[49] Rudnick, H. and Juan-Pablo Montero, _Second Generation Reforms In Latin America And The California Paradigm_, Pontificia Universidad Católica de Chile, December 2001
[50] Watts et al, _Second Generation Reforms In Chile, Power Exchange Model, The Solution_, Department of Electrical Engineering, Universidad Católica de Chile, 2002
[51] Botterud, A. and M. Korpås, _Modelling of power generation investment incentives under uncertainty in liberalised electricity markets_, www.saee.ch/saee2004/botterud.pdf, 2004

3 How effective are these mechanisms at delivering system reliability and sufficient reserve capability?

3.1 New England

As noted in Section 2, there has been widespread acceptance in New England that the existing 'investment envelope' of capacity tickets and energy prices are failing to provide required investment outcomes. These concerns have been expressed both in terms of a lack of signals to invest, or conversely as the existence of signals not to invest[52].

There has been considerable debate as to why the mechanisms in place (particularly the capacity tickets system) were failing, with many focussing on an absence of 'scarcity rents' to make it profitable for reserve 'peaking' capacity to enter the market through new investment or to continue operating consistent with conventional levels of reliability[53]. The scarcity rents were an outcome of the prices available in the market driven spot energy and operating reserve markets in New England[54].

As part of its LICAP support package (the 2005 precursor to the current FCM proposal), the New England ISO made clear its view of the effectiveness of the current New England market mechanisms when it noted in a submission to the US Congress made in August 2005 that "*new investment in generation is not taking place in New England because the current market design is incomplete and does not afford suppliers an opportunity to recover their costs*[55]. This was being felt most acutely in Connecticut, which would in likelihood face a capacity shortage as early as 2006, and *" is likely to grow with time - to approximately 670 MW by 2009"*[56].

In the absence of markets adequate for encouraging new investment, the ISO noted that impacts were being felt on system reliability, and then by consumers. In a quest to have its 2005 LICAP capacity mechanism approved, the ISO noted that were the LICAP not to be approved, then "*the ISO will be forced to procure short-term, out-of-market resources. Existing generators who are unable to earn sufficient revenues in the current market but are needed for system reliability will seek special cost-of-service treatment in the form of expensive Reliability Must Run ("RMR") contracts. These costs are most often a direct pass-through to consumers - since they cannot easily be hedged through the bilateral "standard offer" arrangements with suppliers"*[57]. We understand that Connecticut's consumers contribute approximately $332.5 million in such payments annually[58].

---

[52] Dr Steven Stoft, *Testimony on behalf of ISO New England on LICAP*, Submitted to FERC, Docket Number ER-03-563-030, Direct August 2003.
[53] Joskow, P. (2003), *The difficult transition to competitive electricity markets in the U.S.*, Working Paper, The Cambridge-MIT Institute Electricity Project, CMI 28, p 67.
[54] ibid.
[55] Letter from ISO New England to Honorable Members of Connecticut's Congressional Delegation, dated August 24, 2005. Available at http://www.iso-ne.com/pubs/pubcomm/corr/2005/ct_delegation_letter_8_24_05.pdf
[56] ibid
[57] ibid
[58] ibid

The Federal Energy Regulatory Committee also agreed that the New England market system was "*failing and that generation resources are not being added at a rate necessary to maintain reliability and assure just and reasonable wholesale power prices.*[59]

We note that this issue remains very current. In March 2006, the ISO New England stated that New England faces a still significant threat to the reliability of its power system because "*the current capacity market has not been sending the right economic signals to encourage new plant and demand response development*[60]". It noted that as early as 2008, the region may not have enough supply to meet its electricity needs on the hottest days of the year, and that this will begin to have a material impact on wholesale prices[61]. By 2010, the situation will be critical.[62]

The structure of the FCM is a direct response to these ongoing reliability and reserve capacity concerns, although its likely success in attracting new entrants and required investment is at this stage untested.

3.2 Western Australia

It is too early for an assessment of the WA energy market and its impact on generation investment. That said, there is no identified shortage of willing generation at present.

The Reserve Capacity Mechanism processes took place in 2004 and 2005, with the 2005 process securing commitments from 11 companies to provide 4115.4 MW of Certified Reserve Capacity to Market Participants who indicated their intention to bilaterally trade their Certified Reserve Capacity in the Bilateral Trade Declaration process. This was a comfortable margin above the minimum determined requirement of 4000 MW of capacity, and as a consequence the IMO cancelled the 2005 Reserve Capacity Auction.

The IMO noted that the additional capacity secured through this process, plus that already secured through the power procurement process, means that adequate capacity is already committed to meet the requirement for the summer of 2008/09 as set out in the Statement of Opportunities Report[63].

The initial response to the reserve capacity mechanism indicates that perhaps the current capacity mechanism is working 'too well' and the price of capacity credits may be too high[64]. We understand that current amendments being considered including introducing a sliding scale which would result in all 'conforming bids' being accepted but the payment for

[59] FERC, Interim Order Regarding Settlement Procedures And Directing Compliance Filing, Docket No ER03-563- 030, October 21 2005. Available at http://www.ferc.gov/EventCalendar/Files/20051021144736-ER03-563-030a.pdf
[60] ISO New England, Capacity Settlement Summary, March 2006. Available at http://www.iso-ne.com/pubs/whtpprs/capacity_settlement_summary.pdf
[61] ibid
[62] Roger Bacon, ISO New England.
[63] IMO, *Reserve Capacity Outcome*, www.imowa.com.au, October 2005.
[64] IMOWA, discussions held on 27 April 2006.

the capacity to all generators (and demand response) being lowered to reflect the excess available capacity[65].

3.3 Great Britain

There has been considerable debate over the effectiveness of the Great Britain market in attracting sufficient generating capacity, and in particular whether the reforms in 2002 to the operations of the market were positive or negative for reserve capacity levels.

England and Wales historically operated under generation reserve margins in excess of 20% and experienced very high levels of reliability. Opinions are divided as to whether this reflected over-capacity in an environment of monopoly rents, with some seeing the pre-2002 pool arrangements as allowing generators to recover prices in excess of marginal cost[66]. Regardless, once new trading arrangements were introduced in 2002, wholesale prices fell to historically low levels, the effects of overcapacity and increased competition put downward pressure on wholesale prices and around 3.5 gigawatts of existing capacity was 'mothballed'[67]. In the summer of 2003, the generation capacity margin fell to 16%[68]. This margin was significantly below, the Great Britain system operator's (NGC), operating target of 20% capacity margin[69].

These reductions had immediate impacts on forward contracts, with winter 2003/04 forward prices increasing substantially from £23/MWh to £33/MWh[70] and peak load increasing from £35/MWh to £55/MWh. Similarly, wholesale electricity prices increased considerably with the average spot price in 2003 increasing 20% on the previous year[71]. Reliability outcomes were also affected and the percentage of unserved energy in 2003/04 (and in 2004/05) was 0.0003%[72].

Rises in contract and spot prices led to the introduction of the 'mothballed' capacity which could be brought on-line quickly and, by the end of 2003, the capacity margin was 20% and no shortfall of generation capacity experienced during the winter.

These events could be interpreted in two different ways. The first interpretation is that the market operated normally and efficiently, and that the series of events provided a demonstration of the effective operation of the new trading arrangements, with forward price

---

[65] ibid.

[66] Ofgem, *Update: Securing Britain's electricity supply*, 5 December 2003, www.ofgem.gov.uk.

[67] ibid.

[68] ibid.

[69] A 20% capacity margin is consistent with what is generally considered an acceptable range. See Roques, F., Newbery, D. and W. Nuttal, *Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA*, www.econ.cam.ac.uk/electricity/publications/wp/ep58/pdf, 2004, p 12.

[70] July and October 2003 base load prices

[71] Roques, F., Newbery, D. and W. Nuttal, *Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA*, www.econ.cam.ac.uk/electricity/publications/wp/ep58/pdf, 2004, p 14.

[72] National Grid, *Report to the Authority for the Gas and Electricity Markets*, 2004/05, www.nationalgrid.com.uk, p 12.

signals giving generating firms advance notice that they can earn more revenues by bringing on capacity[73]. This is the published view of the UK Regulator and was also confirmed from our discussions with that office. The second interpretation is that the market was saved by mothballed capacity and by the actions of the NGC, and that insufficient time would have been available for new plant to be built. This is the industry view.

In support of the latter view, the NGC in October 2003 initiated a 'Supplemental Standing Reserve Tender' under which it procured a total of 825MW of reserve at a total cost of £18.87 million and developed a Maximum Generation Service for winter 2003/04 which allowed generators to produce more than their registered plant capacity in emergency situations[74]. While the MGS was not used, the actions taken by NGC have raised questions over the sufficiency of price signals alone to ensure supply adequacy.

While the new arrangements have arguably provided adequate short-term security of supply, it is yet to be seen whether they will provide appropriate signals to ensure long-term investment. The 2005 Seven Year Statement states that a total of 1779MW of new generation capacity is to be completed over the next three years – adequate to meet forecast growth.[75].

Discussions held with the Energy Retail Association of the United Kingdom (ERA) noted that forward contract prices over the past few years have significantly increased, which has improved conditions for investment in generation.

The ERA stated however that the focus of current debate was not on the electricity market design (noting a high level of regulatory reform fatigue) but on Government policy settings. A significant concern, is securing future fuel sources, given the declining gas reserves in the North Sea (the UK's principle source of gas). The UK market is currently awaiting the release of the Government's Energy Policy, expected in mid 2006, to provide the direction and certainty (particularly with respect to nuclear power) necessary to underpin future investment[76].

3.4 Nord Pool

The Scandinavian countries operated under large generation reserve margins of around 50% in Denmark down to 23-27% in Finland, Norway and Sweden prior to Nord Pool. These margins have fallen since the start of the Nord Pool arrangements, but remain within NEM

[73] Ofgem, *Update: Securing Britain's electricity supply*, 5 December 2003, www.ofgem.gov.uk

[74] Roques, F., Newbery, D. and W. Nuttal, *Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA*, www.econ.cam.ac.uk/electricity/publications/wp/ep58/pdf, 2004, p 16.

[75] Ogfem, *Ofgem's submission to the European Commission (DG TREN) Report*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG _DOCS/NATIONAL_REPORTS, 2005, p 83.

[76] Mr Duncan Sedgwick, Chief Executive Officer, Energy Retail Association (UK), discussions held on 27 April 2006.

like tolerance levels. In 2004, Sweden had 25MWh of unsupplied energy, which equates to 0.0002% of total energy supplied[77].

There have been power disturbances in Nord Pool countries; however these tended to relate to system failures and water shortages rather than inadequate investment in generation. On the former, in late 2003, the Nordic power system experienced it's most severe disturbance in 20 years resulting in the southern part of Sweden and the eastern part of Denmark (including Copenhagen) being blacked-out. The outage occurred during a period of moderate demand and was not attributed to a shortage of supply in the market. It arose from an initial loss of generation due to a problem with the operation of the generating unit followed closely by a fault in a busbar leading to two further generation units tripping[78].

On the latter, the recent shortage of water in Swedish and Norwegian reservoirs has contributed to a significant power deficit in the hydro-dominated systems and increased reliance on imports from outside the Nordic area[79]. These water shortages resulted in higher average and peak prices being experienced in 2003 and 2004 on the Nord Pool day-ahead market. The average system price increased from A$42.56/MWh in 2002 to A$61.62/MWh in 2003 and A$51.24/MWh in 2004. In 2003, Nord Pool experienced its highest system price of A$207.72/MWh[80].

As noted in chapter 2, and despite the levels of reliability noted above, the Swedish market has been the subject of debate over adequate investment signals. Under the Nord Pool spot market mechanism, a single price area for Sweden is maintained despite significant internal transmission constraints. This practice has sparked criticism that this has artificially reduced the price in southern Sweden and therefore dampened the signals to power companies to invest[81].

These events and concerns have sharpened the focus on reliability of the electricity system. There is currently significant debate among the Scandinavian countries with respect to supply adequacy issues. One view is that the issue is unlikely to be resolved through Nord Pool market mechanisms as the current forward prices are not sufficiently high to signal significant generation investment. It was considered that the debate itself, and the involvement of big business and politicians, are likely to provide the strongest signals for new capacity[82].

---

[77] Svenska Kraftnat, *Annual Report 2004,* www.skv.se.

[78] Svenska Kraftnat, *The Black-out in southern Sweden and eastern Denmark*, September 2003, www.svk.se/upload/3813IEEE_engleskpresentation_jul2003_2230.pdf, November 2003.

[79] Nordel, *Annual Report 2004*, www.nordpool.com/information/publications, p 9.

[80] ibid, p 7. Note that the system price is the price of spot power contract for next-day delivery. This price does not take into account transmission grid capacity limitations between member countries which may result in higher or lower prices in different price areas. The system price is used as the reference price for trading in Nord Pool's financial market.

[81] Power in Europe, *Nord Pool Market Review*, Issue 465-466, 19 December 2005, p 5.

[82] Mr Terje Lysfjord, Senior Vice President, Nord Pool Consulting ASA, discussions held on 26 April 2006.

In a similar process to the current energy reform process in Australia, the Nordic Council of Ministers is examining the operation of the electricity system. The broad consensus of the energy Ministers is that greater harmonisation of the Nordic electricity systems will improve the operational reliability of the system. A particular concern has been the management of peak loads which occur during extreme winter weather conditions.

The Council of Ministers has commissioned Nordel (the collaborative organisation of the Transmission System Operators of Denmark, Finland, Iceland, Norway and Sweden) to identify proposals to coordinate system responsibility, organise and finance joint investments in transmission networks, and manage the peak-loads of the Nordic countries[83].

The following progress has been made under the reform process:

- Nordel has initiated a study to be finalised by December 2006 to identify proposals for managing peak generation capacity and peak load. The main aims are to improve the information available regarding the supply / demand balance. This is intended to assist market players with financial decisions including decisions to invest in new power plant capacity. The information is also intended to be used as background for the decision to start-up a tendering process for acquiring additional generation and demand-response resources[84].

- Nordel is seeking to introduce initiatives to enhance demand response. Under the current market design market players can make demand response bids. Nordel has identified, however, that the incentives under the current market design and the lack of frequent price spikes in the day-ahead market may not be sufficient to encourage a significant demand response. Nordel is encouraging Nord Pool to develop products that will encourage demand response bidding including introducing new bid types that are more attractive to market players offering demand response[85].

- The transmission system operators in each of the member countries have agreed to augment the transmission network in five places. It was agreed that the new investment would be financed bilaterally between countries supplemented by congestion rents[86].

- Nordel is considering principles for managing transmission congestion in the short to medium term. The TSO's are split between creating a larger number of potential price areas (to improve price signals for transmission and generation investment decisions) or creating fewer and larger potential price areas by using counter trade[87] (to reduce market concentration and improve competition).

[83] Nordel, *Annual Report 2004*, www.nordpool.com/information/publications, p 6.
[84] Nordel, *Status of Nordel's work on Enhancing Efficient Functioning of the Nordic Electricity Market*, www.nordel.org/Content/Default.asp?PageID=129, p 16.
[85] ibid, p 17.
[86] Nordel, *Annual Report 2004*, www.nordpool.com/information/publications, p 6.
[87] Nordel, *Status of Nordel's work on Enhancing Efficient Functioning of the Nordic Electricity Market*, www.nordel.org/Content/Default.asp?PageID=129, p 6. Counter-trading is the purchase/sale of electricity by the

3.5 Chile

Reform of the Chilean electricity sector commenced in 1982, making it one of the first countries to undertake actions that later became a standard reference for reform in other countries[88]. The Chilean system, however, was heavily dominated by hydroelectricity and, with a small number of market players, further revisions to the market design were necessary by the late 1990s.

In 1998-99, this reliance on hydro-electricity was tested when Chile experienced severe drought conditions impacting on the SIC system. In early 1999 these conditions culminated in curtailment of electricity supply in Chile's capital, Santiago, for 3 hours per day as well as frequent power outages. The issue for Chile at that time was therefore not a lack of generation, but a lack of diversity of generation[89].

There were other issues that required attention. Commentators identified a significant cause of the failure in the system as the extreme rigidity of the price system (which set regulated prices on a half yearly basis) and its inability to accommodate the large supply and demand shocks inherent in the hydro-dominated system. Because generators were unable to pass on the full cost of energy to users, the then price system made it worthwhile to postpone or avoid the installation of additional capacity[90], and acted as a deterrent from supplying new customers[91].

Chile introduced the first of two waves of reform in 2004, aimed at better signalling investment in wholesale markets and to address some of the most pressing shortcomings of the current system. In January 2004, *Ley Corta I* was passed and one of the key issues it sought to address was the "*perceived unwillingness to invest in new generation and transmission facilities given the low node price and problems with [sic] agreeing payments for new transmission lines*"[92].

The elements of the reform package are now entrenched parts of the Chilean market design and included:

- Reducing the allowed variance between the node price and the unregulated price from 10% to 5%,

transmission system operator to reduce the transmission of electricity in a constraint on the grid. (Source: Svenska Kraftnat, Annual Report 2004).

[88] Fischer, R. and A. Galetovic, *Regulatory Governance and Chile's 1998-1999 Electricity Shortage*, info.worldbank.org/etools/docs/library/64592/2704.pdf, p 2.

[89] In rainy years nearly all of Chile's consumption can be satisfied by hydro generation but in dry years it can supply only 40% of generation. See Fischer, R. and A. Galetovic, *Regulatory Governance and Chile's 1998-1999 Electricity Shortage*, info.worldbank.org/etools/docs/library/64592/2704.pdf, p 5. In rainy years nearly all of Chile's consumption can be satisfied by hydro generation but in dry years it can supply only 40% of generation

[90] Fischer, R. and A. Galetovic, *Regulatory Governance and Chile's 1998-1999 Electricity Shortage*, info.worldbank.org/etools/docs/library/64592/2704.pdf, p 17.

[91] Fossil Energy International, An Energy Overview of Chile, www.geni.org/globalenergy/library/national_energy_grid/chile, 2002.

[92] Pollitt, M., *Electricity Reform in Chile – Lessons for Developing Countries*, www.mit.edu/ceepr/www/2004-016.pdf, 2005, p 8.

- Reducing the threshold for unregulated customers from 2MW to 0.5MW;

- Changes to improve price signals to encourage reserve generation expansions by defining sub-systems on the basis of transmission constraints and defining the theoretical power reserve margin and the transmission loss factors for each sub-system; and

- Provision for a price-bid (as opposed to cost-bid) market for ancillary services to be introduced[93].

Chile's reliance on hydro-electricity remained a threat to system reliability throughout these reforms. In 2004, the Argentinean Government imposed restrictions on the level of natural gas exports to Chile following the collapse of its currency. This caused Chilean generators to rely on alternative and more expensive fuel sources and consequently resulted in significant increases in the 6 monthly node price for electricity in the SIC system – an increase of 7% in May 2004 and an increase of 10% in November 2004[94].

This event also fuelled regulatory debate about the need to address security of supply issues in the Chilean electricity sector. At the time, commentators noted that "i*nvestment in generation has since stalled and, as of May 2005, the probability of an energy shortage during the next three years was estimated to be on the rise"*[95].

Further reforms were introduced in 2005 (termed *Ley Corta II*) aimed at improving security of supply, and included:

- Establishing an auction process to facilitate competitive bidding for the regulated node price of energy (that is, energy for sale to regulated customers). New contracts between generators and distributors were to be signed and were able to have a term of up to 15 years. The price set at auction is to be kept unchanged in real terms over the duration of the contract (adjusted periodically for changes in fuel and other costs);

- Allowing generators to offer incentives to regulated customers to reduce consumption in shortage situations. These incentives complement the existing compensation mechanism;

- Further changes to the upper and lower bounds of the freely negotiated price of energy within which the regulated price of energy must fall allowing prices to increase much faster in response to adverse supply shocks.

[93] *Power Bill and Regulation of the Electric Sector*, Libertad Desarrollo, No. 663, January 30, 2004, p 1 – 6.
[94] Pollitt, M., *Electricity Reform in Chile – Lessons for Developing Countries*, www.mit.edu/ceepr/www/2004-016.pdf, 2005, p 12.
[95] Galetovic A. and L. Mello, *Strengthening Regulation in Chile: The Case of Network Industries*, OECD Economics Department Working Papers No.455, October 2005, p 9.

Policy makers in Chile have also debated further reforms to the wholesale electricity market, in particular, replacing the current simulated spot market with an unregulated market. The primary concern with this proposal has been the high degree of concentration in the generation market and the potential for the exercise of market power[96]. This concern appears to have stopped any move away from the current cost-based approach.

There is limited material on which the effectiveness of the new reforms can be assessed. A recent report from the Economist Intelligence Unit suggests that there has been some impact:

> *High and rising electricity tariffs-by the end of 2005 were 75% above their 1998 level-coupled with the completion of this new regulatory regime through Law 20,018, which came into force in May 2005, have triggered a major investment drive by electricity generation companies, including several new market participants. However, most of their new capacity will come on stream only from the second half of 2008*[97].

[96] Arellano, M.S., *Diagnosing and Mitigating Market Power in Chile's Electricity Industry*, http://www.web.mit.edu/ceepr/www/2003-010.pdf, 2003, p 2.

[97] Economist Intelligence Unit, *Chile economy: Heading for an energy crisis?*, www.viewswire.com, March 8, 2006.

4 How the mechanisms impact on financial market liquidity and availability of hedge contracts from generators?

4.1 New England

A study by the Edison Electric Institute found that the New England hedge contract market was sufficiently liquid[98]. This was confirmed through our discussions with the ISO New England, during which we were advised that the market has high levels of liquidity, and that the day ahead markets are transparent.

Lack of market concentration has also supported liquidity in the market. While the New England market was once highly concentrated the addition of approximately 10,000 MW of gas-fired generation has entered the market since 1999[99]. The ISO reported in 2005 that more than 260 companies and entities participate in (the New England) markets and complete more than $7.25 billion of wholesale electricity transactions annually[100] from a base of around 31,000 MW of installed capacity[101].

The New England ISO noted in 2005 that on average, at least about 73% of total real-time load obligation was either forward contracted or covered by a physical hedge in 2004. For each month of 2004, the degree of forward contracting was at least 70% of real-time load obligation. The results for 2003 were similar. The ISO noted that this understated the degree of forward contracting that actually takes place to the extent that bilateral contracts exist but are not settled through the ISO's centralized settlement system. They also understate the physically hedged load to the extent that non-dispatched generators are available in that market[102].

4.2 Western Australia

The WA energy market is expected to commence operations on 1 July 2006. No information is therefore available on the liquidity of the mechanisms in that market.

There has been concern, however, over market concentration in Western Australia and the impact this may have on competition and potentially the ability for market participants to gain hedge cover. The Government has put in place vesting contracts, as a transitional measure, that cover the majority of the load. A cap of 3000MW has also been placed on Verve (formerly Western Power Generation) in developing capacity.

---

[98] Energy Security Analysis, *Final Report to Edison Electric Institute*, Hedging Instruments in US Power Markets, Overview of Liquidity and Gap Analysis, 21/9/2001, p 28.
[99] ISO New England, Power Generation and Fuel Diversity in New England, Ensuring Power System Diversity, August 2005. Available at http://www.mtpc.org/renewableenergy/public_policy/DG/resources/2005-08-25_iso-ne_diversity-reliability.pdf
[100] ISO New England, Letter to US Department of Energy, 21 Sept 2005 available at http://www.electricity.doe.gov/document/isonewengland.pdf
[101] ISO New England market presentation at http://www.nhiof.org/workshops/atcpresentations/babula.ppt#388,4,Slide 4
[102] ISO New England, *Annual Markets Report*, 2004

4.3 Great Britain

As noted previously, the Great Britain market is the subject of considerable debate, specifically as to whether the 2002 market reforms improved or negatively impacted the operations of the energy market.

The available information supports a view that liquidity has decreased since the reforms. As of April 2003, one reputable report showed England and Wales had, for market hedges, a ratio of traded amount over physical demand of 9[103].

Since that time market liquidity had dramatically declined, with volumes reduced from 8-10 times to just twice the physical consumption[104], causing "*a lack of market transparency and a large difference between the buying ("bid") price and the selling ("offer") price*"[105].

The link between the reforms to market design in 2002 and the observed reductions in liquidity is debated. Non-market design issues such as barriers to market entry, the level of vertical integration and the failure of financial traders and speculators to enter the market in a significant way have been discussed as other possible causes[106], but no definitive statement has been made by the UK Government or NGC on the issue. In our discussions with Ofgem, the view was forwarded that significant vertical integration in 2005 has contributed to the reduction in liquidity, with Market Customers increasingly hedging their load physically, rather than financially[107].

The Futures and Options Association (FOA)[108] has recently announced that it is commencing a new project to identify the reasons for declining liquidity on the UK power markets and to put forward recommendations to arrest this trend. Specifically the project will address the following issues:

- barriers to entry to power markets for financial traders;
- creating a new reference price or improving the existing reference price; and
- removing or consolidating diffuse credit pools possibly via a clearing solution[109].

The Chair of the FOA supports the introduction of an energy exchange for Great Britain to establish a reference price against which physical and financial instruments can be indexed.

---

[103] International Energy Agency, *Power Generation Investment in Electricity Markets*, www.iea.org/textbase/nppdf/free/2000/powergeneration_2003.pdf, p 45 - 48.
[104] RWE, *An energy exchange for the UK*, www.rwe.com, 10 April 2006.
[105] ibid.
[106] Littlechild, S., *Smaller Suppliers in the UK Domestic Electricity Market: Experience, Concerns and Policy Recommendations*, www.ksg.harvard.edu, June 2005, p 48.
[107] Ms Sophie Tolley, Ofgem.
[108] The Futures and Options Association is a UK based industry association for businesses operating in derivatives.
[109] Futures and Options Association, *New Project to Address Falling UK Power Market Liquidity*, www.foa.co.uk.

4.4 Nord Pool

The Nord Pool market is generally recognised as the most liquid European electricity derivatives market, offering a wide variety of financial products including futures, forward, options and contracts for differences[110]. Market observers have noted that there is currently "great confidence" in the operation and liquidity of the day ahead and no significant concerns or complaints about liquidity in the future and forwards markets[111].

The Nord Pool group has established markets for trade in standardised power contracts including both physical and financial contracts. The Elspot and Elbas spot market trade in hourly power contracts for physical delivery. After Elspot closes, Elbas allow continuos trading in hourly power contracts up until one hour before the delivery hour.

The market has also adapted its product offerings to meet the needs of market players. Recently Nord Pool shortened its futures horizon to 6 weeks while maintaining a four year horizon for forwards. This was in response to a market preference towards short-term futures close to due date and long-term forwards towards the end of the time horizon[112].

While there remains a significant level of bilateral contracting outside the market, participation in the market is increasing. In 2004, over 40% of total electricity trading in the Nordic countries was carried out via Nord Pool[113]. The trade in financial contracts (excluding non-cleared financial contracts) is approximately five times the physical load[114].

4.5 Chile

The Chilean market is a cost based, rather than price based market. While it does have a spot market – it is a regulated spot market whereby prices are set at each node of the interconnected system rand based on the weighted average of short run marginal costs of generation for the entire system optimized over a 12- or 48-month horizon. The marginal cost of the last generator required to balance supply and demand, taking in to account transmission constraints and losses, determines the spot price at each node[115]. Liquidity is therefore not an issue as the financial market always clears.

---

110 International Energy Agency, *Power Generation Investment in Electricity Markets*, www.iea.org/textbase/nppdf/free/2000/powergeneration_2003.pdf, 2003, p 43.

111 Mr Terje Lysfjord, Senior Vice President, Nord Pool Consulting ASA, discussions held on 26 April 2006

112 Nord Pool, *Trade at Nord Pool's Financial Market*, www.nordpool.com/nordpool/financial/index.html, p 7.

113 Swedish Energy Markets Inspectorate, *Annual Report to the European Commission*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS, 2005, p 18.

114 Nord Pool, *Trade at Nord Pool's Financial Market*, www.nordpool.com/nordpool/financial/index.html, p 23.

115 Arellano, M.S., *Diagnosing and Mitigating Market Power in Chile's Electricity Industry*, http://www.web.mit.edu/ceepr/www/2003-010.pdf, 2003, p11-12.

5 How reliability standards are determined in those markets[116]?

5.1 New England

The ISO's Reliability Standards[117] establish minimum design criteria for the New England bulk power supply system. These provide that resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting non-interruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year[118].

The factors are:

- The possibility that load forecasts may be exceeded as a result of weather variations.
- Immature and mature **equivalent forced outage rates** appropriate for generating units of various sizes and types, recognizing partial and full outages.
- Due allowance for scheduled outages and deratings.
- Seasonal adjustment of **resource** capability.
- Proper maintenance requirements.
- Available operating procedures.
- The reliability benefits of interconnections with systems that are not Governance Participants.
- Such other factors as may from time-to-time be appropriate.

The ISO's existing reliability standards are not set to change in circumstances where the FCM is approved and implemented.

5.2 Western Australia

The IMO in WA has the duty to forecast generation adequacy over a period of 10 years and to ensure that sufficient Reserve Capacity is procured. While the market is not yet fully

---

[116] While noting the inter-relationship between generation and transmission reliability, the following section does not review the reliability standards for networks as it is beyond the agreed scope of this report which is to focus on generation capacity and capability.

[117] ISO New England Planning, *Procedure no. 3, Reliability Standards For The New England Area Bulk Power Supply System*, www.iso-ne.com, February 1, 2005.

[118] ibid at page 3.

operational, the following provides information on what will occur to ensure system reliability.

Each year the IMO will prepare a Statement of Opportunities Report outlining projected capacity requirements for the SWIS and projected capacity shortfalls for each of the next ten years. This report will indicate opportunities for supply and demand augmentations that would improve the adequacy and security of the power system. The IMO will not consider transmission planning, as Network Operators will address this, but the Statement of Opportunities Report may make use of transmission planning information provided by Network Operators.

The IMO will determine the capacity required in each year so as to:

- meet the forecast peak demand after the outage of the largest generation unit and while maintaining some residual frequency management capability (e.g. 30 MW), in 9 years out of 10;
- and to limit energy shortfalls to 0.002% of annual energy system consumption.

5.3 Great Britain

Similar to the NEMMCO Statement of Opportunities, the NGC is required to provide information regarding forecast supply and demand balance in its Seven Year Statement. There is no explicit obligation, however, on the NGC to maintain supply adequacy.

The Statement details information on existing and new generation capacity, generation disconnections, generation plant mix in terms of fuel type and location and plant margins. The Statement also provides information on the characteristics of the existing and planned transmission system, its expected performance and capability and other related information. The information is provided to allow existing and prospective market participants to evaluate opportunities in the electricity sector.

NGC has adopted a 20% capacity margin target for planning and operational purposes. NGC also publishes estimates of reserve margins for a number of scenarios for future generation capacity and load growth.

5.4 Nord Pool

Reliability standards are the responsibility of the Nord Pool member countries. Each country has different requirements with respect to system responsibility. Unlike the National Electricity Market there is no explicit reliability target.

The Nordic Council of Ministers, as part of its ‘harmonisation work’, has requested a survey of how system responsibility is defined in each member country assess the reasons for these differences. Appendix B summarises the existing obligations of the transmission system operators (TSO) of member countries[119].

5.5 Chile

There is no equivalent to the 1 day in ten year reliability standard used in the NEM or in other countries. Indeed, the absence of a clear system security target has been the subject of recent debate.

Some academics have noted the problems of "generators receiving payments for the capacity made available, with no distinction made related to the impact in the whole system security[120]", and suggested that "it is important that security standards are included in the regulatory frameworks to define the system level of security"[121].

Endesa Chile, responsible for around 38% of the electricity produced in Chile and one of the largest players, reported 98.90% reliability (probability of generation facilities dispatching on demand) in March 2005 in a corporate briefing[122].

---

[119] Unless otherwise referenced, the table summaries information provided in: Hagman Energy AB, *Survey of system responsibility in the Nordic Countries*, www.nordel.org/Content/Default.asp?PageID=129, 2005.

[120] Vignolo, M., *The Influence of Market Regulations in the Development of Distributed Generation*, paper at http://iie.fing.edu.uy/investigacion/grupos/syspot/InfReg_DG.pdf

[121] Ibid.

[122] Corporate briefing available at http://library.corporate-ir.net/library/10/106/106239/items/143796/eoc_050329.pdf

6 How the markets differ from the NEM and would the mechanisms be compatible with the current NEM design?

6.1 Background

Rather than detail each of the systems one by one, this chapter instead considers the key mechanisms identified in the previous chapters as central to the creation of investment signals and assesses, at a high level, their compatibility with the NEM.

In preparing this information, we note the previous consideration of capacity mechanisms by NECA in 2002[123], which all retailers were involved in and contributed to. Where we have presented a view based on information prepared by NECA, or contributors to that process, this has been clearly identified.

The types of markets covered in this chapter are:

- Markets with capacity mechanisms of various types, as in New England, Western Australia and Chile;
- Energy only markets;
- Day ahead markets;
- Price caps;
- Markets with a net pool; and
- Markets with cost-based arrangements.

These are considered below.

6.2 Capacity mechanisms (New England, Western Australia, Sweden and Chile)

The concept of capacity payment is rooted in the theory of peak load pricing, where generation of electricity requires two factors of production; capacity and energy, and the amount of energy is constrained by the available capacity. According to the theory, energy is priced at marginal cost and a capacity payment that would recover the fixed capacity cost is imposed on the peak-period energy users[124].

---

[123] NECA, *Capacity Mechanisms, The Options*, www.neca.com.au, 2002, p 46.

[124] Roques, F., Newbery, D. and W. Nuttal, *Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA*, www.econ.cam.ac.uk/electricity/publications/wp/ep58/pdf, 2004, p 43.

The purpose of the capacity mechanism is clear. In markets where the energy only cost represents the marginal cost of production, capacity mechanisms provide a return on capital. Capacity mechanisms, in this way, function as a signal for investment in generation.

Since the liberalisation of energy markets numerous designs for capacity mechanisms have evolved. A key distinction between different designs has been whether the regulator sets the price for capacity and the quantity is then determined by market forces or the regulator sets the amount of capacity required and the market sets the price. The weight of opinion has fallen in favour of setting the capacity requirement[125].

Four different type of capacity markets have been set out in the preceding chapters, being:

- A descending clock capacity auction (New England);
- A reserve capacity mechanism (WA);
- A fixed capacity payment (Chile); and
- System operator capacity (Sweden).

Each is summarised below, together with consideration in section 6.2.5 of whether the mechanism would be compatible with the NEM.

6.2.1 Descending clock capacity auction

The effectiveness of the auction based capacity mechanism proposed in New England is yet to be tested in practice. From a theoretical perspective, however, there are a number of positive elements in the proposed capacity mechanism. The mechanism sets the requirement for capacity and allows the market to determine the price (within set parameters) thereby minimising any efficiency loss. The design also allows capacity to be provided by a variety of suppliers including traditional generating plant, intermittent resources and demand response.

In theory, the operation of the auction mechanism should result in the compensation received by suppliers for capacity approximating the cost of new entry. This should provide appropriate compensation for existing generators and attract and retain new entry.

It is important to recognise however that the timing and structure of New England's FCM is a direct response to the increasingly critical nature of its reserves. That is, many of its key elements including the proportion of forecast installed capacity requirements to be procured by the ISO (100 percent), the period allowed for infrastructure establishment (3 years), and the timeframe for implementation upon scheme approval (as early as October 2006), appear heavily influenced by suggestions that supply in the system will be unable to be met from as early as 2008.

---

[125] Barrera, F. and J. Crespo, _Security of Supply: What Role Can Capacity Markets Play?_' Research Symposium European Electricity Markets, September 2003.

6.2.2 Reserve Capacity mechanism

The reserve capacity mechanism adopted in Western Australia features of a mixture of the capacity tickets mechanism and the capacity payments discussed by NECA in 2002. In a capacity tickets system, retailers have an obligation to hold sufficient capacity ticket to cover their peak load during the contract period, plus a margin for reserve loads[126]. In the WA reserve capacity system, retailers are required to hold Capacity Credits to cover their share of the total System Requirement[127].

In a capacity tickets system, retailers are penalised for not holding sufficient credits[128], whereas the WA system requires retailers who do not procure sufficient Capacity Credits bilaterally to fund capacity procured through the Reserve Capacity auction[129]. The auction, essentially a central planning tool, is the main similarity to the traditional capacity payments mechanism whereby generators receive payment from a central planning entity for the amount of capacity they make available[130].

As noted above in Section 2, it should be noted that the reserve capacity model has been developed in direct response to concerns regarding the timely commissioning of capacity resulting from the *"energy island"* characteristics of Western Australia[131].

6.2.3 Fixed Capacity Payment

The Chilean electricity market design incorporates a fixed capacity payment[132], which provides payment to generators contributing to capacity in the yearly peak demand period (May - September), with payment depending on availability, time to start and time to full load.

Capacity charges reflect the annual marginal cost of increasing system capacity assuming a specified reserve margin and reflect the capital and operating costs including a 10% return of the newest technology on the system adjusted by a capacity penalisation factor[133] - fixed at 5.25 US$/kW/month[134].

---

[126] NECA, *Capacity Mechanisms, The Options*, www.neca.com.au, 2002, p 46.

[127] IMO, *Whole Electricity Market Design Summary*, www.imowa.com.au, p 4.

[128] NECA, *Capacity Mechanisms, The Options*, www.neca.com.au, 2002, p 47.

[129] IMO, Whole Electricity Market Design Summary, p 4.

[130] NECA, *Capacity Mechanisms, The Options*, www.neca.com.au, 2002 p 48.

[131] Office of Energy, Government of Western Australia, presentation at www.eriu.energy.wa.gov.au/cproot/710/3912/6th%20Energy%20Conference%20-%20Perth.pdf , 2004

[132] Barrera, F. and J. Crespo, *Security of Supply: What Role Can Capacity Markets Play?*' Research Symposium European Electricity Markets, September 2003.

[133] Pollitt, M., *Electricity Reform in Chile – Lessons for Developing Countries*, www.mit.edu/ceepr/www/2004-016.pdf, 2005, p 5.

[134] Rudnick, H. and Juan-Pablo Montero, *Second Generation Reforms In Latin America And The California Paradigm*, Pontificia Universidad Católica de Chile, December 2001

6.2.4 System Operator Capacity Requirements

In Sweden, the system operator is required to hold up to 2,000 MW of generation or demand response maintained through agreements with generators and the demand-side. The system operator is required to pay a 'capacity fee' as consideration for these agreements. The apparent policy driver behind this requirement is a concern that the market has not (and will not) deliver sufficient capacity to meet demand in periods of extreme winter weather conditions.

We were unable to find any evidence regarding the effectiveness of this mechanism and whether it has directly or indirectly encouraged increased supply or demand-side investments. In this context, it is worth noting, that this mechanism is only being employed in Sweden as a temporary measure. The authorities anticipate that over time a market-based solution, involving the other Scandinavian countries, will be created to 'manage' peak load, potentially involving a tendering process for acquiring additional generation and demand-response.

6.2.5 Compatibility with the NEM

In technical terms, each of the capacity mechanisms outlined above could be compatible with the NEM design. That is, we do not consider that there are any structural issues that would prevent a capacity mechanism being adopted.

However, the implementation and operation of all new market mechanisms imposes costs on the operation of the market. As such, good policy requires that there is a demonstrated benefit (or need) which would justify the additional cost. The costs associated with introducing a capacity mechanism include:

- organisational capability and resourcing within regulatory agencies to accurately set the appropriate capacity requirements or the appropriate and efficient capacity price (in the case of fixed payments);
- design of the auction mechanism (New England model);
- ongoing administration of the mechanism, including the periodic review and reset of capacity charges or the management of an auction process; and
- the regulatory risk on market participants arising from inaccurate regulatory settings (including potential for under or over-capacity), unknown interaction with the energy market, and potentially adverse impacts on market confidence as a result of a high level of regulatory intervention in the management of the capacity mechanism.

Consideration is also required of the impact that the introduction of a capacity mechanism would have on the parameters of the NEM's existing 'investment envelope'. In particular, it should not be assumed that the introduction of a capacity mechanism would automatically result in a concurrent reduction in the level of VoLL or the CPT, particularly in light of significant lead-times for the establishment of new generation investment and the relatively conservative basis upon which the NEM's reliability requirements are set. As a result, Market Customers may find themselves 'paying twice' for the delivery of required reliability with no accompanying amelioration of energy market outcomes or lessening of prudential requirements.

The introduction of capacity markets was considered extensively by NECA in 2002, and discounted on the basis that "*the current NEM design has resulted in sufficient capacity being built*"[135]. NECA did note that reserve contracting, a co-optimised capacity market and a dedicated capacity reserve would be expected to result in a higher standard of reliability, but that this additional capacity would likely be out of proportion with the "*perceived weakness of the current market model and the value society places on supply reliability*"[136].

In light of this, both the capacity tickets mechanism and the capacity payments mechanism were dismissed by NECA[137]. In submissions to that review, almost all generators doubted the benefits of a capacity mechanism relative to the current energy only system[138], as did the majority of retailers[139]. Ergon Energy, in particular, recommended that no further action be pursued until "*a failure of the bi-lateral contract market can be demonstrated*"[140].

6.3 Energy only (Great Britain & Nord Pool)

We have given this issue cursory treatment, given that the NEM market is energy-only. There is merit, however, in discussing the benefits of an energy only market in the literature, particularly on the subject of VoLL.

Energy only markets have considerable economic precedent, and substantial support in the economic literature, with most pointing to the NEM experience as proof[141] of workability without serious issues. The rationale for energy only markets appears to be that it allows markets to clear[142], that it encourages long term contracting[143] (to avoid price spikes) and that it allows capacity cost recovery by generators.[144]

It is, not surprisingly, not the way in which energy only markets are designed that results in difficulties within these markets, but issues of practicality, public policy and market power. On the first issue, the non-storability of electricity, demand and supply uncertainty, inelastic

---

135 NECA, *Capacity Mechanisms The Options*, www.neca.com.au, 2002, p 49.

136 ibid, p 50.

137 Consideration of both mechanisms was not undertaken in section 6 (Evaluation) in the NECA Report.

138 NECA, *Capacity Mechanisms Responses to Consultation*, www.neca.com.au, 2002, p 3.

139 ibid, p 4.

140 ibid, p 5.

141 http://www.puc.state.tx.us/rules/rulemake/24255/061705/Dauphinais3.pdf. This document by the "Alliance for Retail Markets in 2005 notes that it

142 Roques, F., Newbery, D. and W. Nuttal, *Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA*, www.econ.cam.ac.uk/electricity/publications/wp/ep58/pdf, 2004, p 4.

143 http://www.puc.state.tx.us/rules/rulemake/24255/061705/Dauphinais3.pdf. This document by the "Alliance for Retail Markets in 2005 notes that it

144 Roques, F., Newbery, D. and W. Nuttal, *Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA*, www.econ.cam.ac.uk/electricity/publications/wp/ep58/pdf, 2004, p 4.

demand and the steepness of the supply curve at its high end all contribute to high price volatility when reserve margins are low[145][146].

Secondly, there is doubt over the power of the 'price spike', of itself, to induce investment, particularly in peaking units. Our discussions with NEM market participants suggests that under investment in peaking units in the NEM may be exacerbated by a preference within public policy circles for base load capacity. Further, the difficulty in distinguishing between the exercise of market power and legitimate scarcity rent often means that economic signals that are needed in order to attract investment can be misinterpreted as market power by policy makers[147].

The tension between generators seeking a return through prices beyond marginal cost, and users seeking to avoid price shocks, has been a determining factor in the setting of price caps such as VoLL around the world. While most agree that a price cap should be set at the real value of unserved energy, or risk inaccurate investment signals, there is little appetite for such a concept in real markets and price caps have been set lower than the representative value of unserved energy. A study commissioned by the Reliability Panel in 2002[148] produced a range of figures from $6,000 to $30,000/MWh, and noted that the calculation of VoLL is an imprecise science. It concluded that the appropriate range was likely to lie between $10,000/MWh and $30,000/MWh. We note that the NEM price cap of $10,000/MWh is the highest that we have encountered in the literature, with New England and other US markets set at $1000/MWh.

The consequence of setting a price cap too low for political or market stability reasons have also been articulated in terms of 'missing money'. When prices are prevented from reaching high levels during times of relative scarcity, price caps reduce the payments that could be applied towards the fixed operating costs of existing generation plants and the investment costs of new plants. The resulting 'missing money' reduces the incentives to maintain plant or build new generation facilities[149]. There is no evidence that we can find suggesting that missing money is a problem in the NEM, suggesting that a higher level of VoLL - while consistent with the current NEM design – appears unnecessary.

A lower VoLL would also be consistent with the current NEM design, although the literature would not seem to support such a concept. As noted, Great Britain and Nord Pool both operate energy only markets with no price cap, and the issue of missing money scarcely arises. In contrast, New England's price cap is $1000/MWh and there is considerable evidence that this feature is contributing to 'missing money' in New England[150,151].

---

[145] ibid, p 40.

[146] Hogan, W., *On an "Energy Only" Electricity Market Design for Resource Adequacy*, September 2005, http://ksghome.harvard.edu/~whogan/Hogan_Energy_Only_092305.pdf, September 2005.

[147] Roques, F., Newbery, D. and W. Nuttal, *Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA*, www.econ.cam.ac.uk/electricity/publications/wp/ep58/pdf, p 41.

[148] NECA, *Capacity Mechanisms the Options*, www.neca.com.au, 2002.

[149] Hogan, W., *On an "Energy Only" Electricity Market Design for Resource Adequacy*, September 2005, http://ksghome.harvard.edu/~whogan/Hogan_Energy_Only_092305.pdf, September 2005, 1.

[150] http://www.pmaconference.com/4.28.06a.pdf

[151] Hogan, W., *Resource Adequacy Mandates and Scarcity Pricing*, February 2006.

Our discussions with most demand-side NEM participants suggest that VoLL is "out of the way" at $10,000/MWh and that a lower VoLL would likely create missing money for peaking plant.

6.4 Short-term market / Day ahead market (Nord Pool)

The Nord Pool market offers a wide variety of financial products including futures, forward, options and contracts for differences[152]. The Elspot and Elbas spot market trade in hourly power contracts for physical delivery, and after Elspot closes, Elbas is available for continuous trading in hourly power contracts up until one hour before the delivery hour.

The concept of a day ahead market or other short term forward market is compatible with the NEM and may provide benefits to the Australian energy market if liquidity can be maintained. We understand that retailers need to manage significant unders and overs in their contract positions given the nature of the market – that is a retailers' position will be long when the price is low and short when the price is high. We understand that standard available forward contracts (balance of quarter & balance of month) do not provide an appropriate hedge in these instances.

We understand that the MCE User Participation Working Group has been reviewing the application of a short term market in Australia, in particular on a voluntary day-ahead market which includes:

- Contracting instruments which allow entities to buy and sell MWh settled against Regional Reference Price each 30 minutes of next day;
- Buyers and Sellers submitting blind bids and offers in a nominated period for a firm day-ahead market; and
- An Operator clearing the bids / offers and between the parties in each trade.

6.5 Net Pool (Great Britain)

The arrangements in Great Britain are based on bilateral contracts with a separate market for system balancing. The philosophy underpinning these 'net pool' arrangements is that the market is best placed to determine efficient outcomes rather than central trading mechanism. In theory, the advantage of these arrangements is that the market, through bilateral contracting, determines the level of capacity required which should lead to more efficient investment outcomes.

The economic literature raises a number of concerns with this decentralised model. A fundamental problem associated with a decentralized model is that it creates multiple markets, not only for spot energy, but for congestion energy, imbalance energy, and ancillary

[152] International Energy Agency, _Power Generation Investment in Electricity Markets_, www.iea.org/textbase/nppdf/free/2000/powergeneration_2003.pdf, 2003, p 43.

services. There is also evidence that net pools have made electricity markets subject to unilateral behaviour that leads to price increases[153].

A net pool arrangement is inconsistent with the current gross pool design in the NEM, and while we are unaware of any technical impediments to moving towards a net pool design, it would involve significant changes to the current operation of the market. Further consideration would also need to be given how net pool arrangements would impact upon transparency and liquidity in the NEM. In this context it is noted that the use of settlement reallocation by participants as currently provided within the NEM design in effect delivers an outcome similar to that under a financial net pool. We understand from discussions with NEM participants that there may be a reluctance for supply side participants in particular to utilise these arrangements due to perceptions regarding increased exposure to credit risk than that provided under the gross ('blind') pool. If this is the case, it may be reasonable to assume that any reduction in prudential requirements accompanying a move from a gross to a net pool would be partially offset by the inclusion of premia in the bilaterial contracts that are established to account for the perception of increased risk.

6.6 Cost based bidding (Chile)

Economic theory dictates that price based bidding will provide better signals for long-term investment given dispatch is based on the scarcity value of electricity rather than current costs. In addition, there are significant transaction costs associated with cost based bidding including auditing of submitted costs and significant opportunity for gaming the regulator in respect of these costs[154]. We have not considered this mechanism in further detail given its lack of support in economic theory, its incompatibility with the current NEM design, and our view that it is unlikely to inform or advance regulatory debate in Australia.

---

[153] Rosellon, J., *Different Approaches to Supply Adequacy in Electricity Markets*, Centro de Investigación y Docencia Económicas (CIDE) and Harvard University, 2004p 4.

[154] Pollitt, M., *Electricity Reform in Chile – Lessons for Developing Countries*, www.mit.edu/ceepr/www/2004-016.pdf, 2005, p 14.

A High-Level Comparison of Markets Reviewed

Issue	New England	Western Australia	Great Britain	Nord Pool	Chile
Mechanisms signalling investment (i.e. the 'investment envelope')	Energy market (incl day-ahead). Price cap of $1,000/MWh. Capacity ticket mechanism (changes pending approval). Bilateral contracting and forward market.	Short-term energy market (STEM). Reserve capacity mechanism. Bilateral contracting. Dispatch / balancing process.	Bilateral contracting. Power exchanges. Imbalance settlement process (compulsory).	Energy market (including day-ahead and intra-day). Forward market. Real time balancing (by member countries). System operator capacity requirement (temporary – Sweden).	Regulated spot price (generator to generator). Regulated node price (generator to distributors / retailers). Unregulated contract market (generators to customers). Capacity payment mechanism.
Effectiveness at delivering system reliability and reserve capability	Failure to provide adequate investment to meet future requirements (in particular, through a. lack of locational signals). Changes to existing capacity mechanism under consideration - Forward Capacity Auction (FCM).	Future effectiveness of market design too early to assess. No identified shortage of reserve capacity at present.	Delivering adequate short-term reserve capacity. Industry concerns regarding regulatory intervention rather than market design.	Concerns regarding system reliability rather than generation investment (e.g. water shortages and system reliability). Process of increased harmonization across Nordic systems under consideration.	Failure to provide adequate investment or system reliability to satisfy existing or future requirements. Reform debate ongoing.

Impact on financial market liquidity and availability of hedge contracts	Liquid – significant forward contracting.	Impact on liquidity too early to assess. Regulatory mechanisms have been introduced to mitigate market power concerns.	Decline in liquidity over time (possible attribution to an increase in the level of physical cover).	Highly liquid – significant level of bi-lateral, forward and futures activity through a variety of financial products.	Lack of liquidity - spot market is regulated and the contract market participation is limited.
Reliability standards	Loss of load expectation (LOLE) of disconnecting non-interruptible customers on average no more than 0.1 days per year.	Two criterion: • Reserve margin at time of system peak; and • 0.002% of unserved energy	No explicit standard. A 20% capacity margin target is adopted for planning and operational purposes.	No explicit common standard. Individual member countries have differing requirements.	No explicit standard.
Compatibility with NEM design	Capacity mechanism would be structurally compatible – subject to cost and transitional issues. Suggestion price cap too low ('missing money'). Effectiveness of proposed auction based capacity mechanism is unknown.	Capacity mechanism would be structurally compatible – subject to cost and transitional issues. Long-term effectiveness of reserve capacity mechanism yet to be tested.	Compatible – energy only market.	Compatible – short-term / day-ahead market. System operator capacity requirement (Sweden) would be structurally compatible – only intended to be temporary in nature.	Capacity mechanism would be structurally compatible however the underlying 'cost-based' market design – is fundamentally incompatible with the NEM.

B System Reliability Obligations in Scandinavian Countries

Obligation	Sweden	Norway	Denmark	Finland
General Obligation	Electricity installations cooperate reliably so that balance between production and use of electricity is maintained in the short-term within the whole or parts of the country.	Ensure that at all time momentary balance between total supply and total consumption of electricity.	Uphold security of supply and effective use of an integrated electricity supply system.	Ensure technical functionality and operational reliability of the national electricity system.
Long-term security of supply	The TSO is required to maintain up to 2000MW of peak load reserve. The reserve must be created by agreements with generators and consumers (demand response) and a capacity fee is payable. (This responsibility remains until Feb 2008. It is understood that the Government expects that in the interim a market-based solution will be created to 'manage' peak load). The TSO is also required to expand the network based on socioeconomic profitability assessments.	The TSO must keep the relevant authorities continuously informed regarding power and energy balances, both short and long term. The TSO is also required to support expansion of regional and central networks in a socio-economically rational way.	The TSO has an obligation to ensure that there is sufficient production capacity in the electricity supply system. Generators with a capacity of more than 25 MW may not be taken out of operation for a long time without approval from the system operator and the TSO can enter into an agreement about postponing plant stoppages. The TSO is required to plan on a 10 year horizon for security of supply including any necessary changes to the network. The Minister of Economic and Business Affairs can direct the TSO to undertake measures to safeguard security of supply.	The TSO has a broad obligation to operate and develop its network and connections according to the reasonable needs of customers to ensure electricity of sufficient quality.

Management of operational disturbances and shortage situations	In emergency situations the TSO can order electricity producers to increase or decrease their level of production. The TSO has gas turbines with a combined output power of 400MW, and signed a long term agreements enabling it to utilise a further 800MW in emergency situations[155].	In emergency situations, the TSO may order distribution networks to reduce or disconnect supply to customers.	When the risk of network collapse is imminent the TSO is able to order the necessary changes in production, trade and consumption without compensation.	The TSO is entitled to impose restrictions on loads and direct the use of active reserve and other generating capacity where operational reliability is jeopardised.

[155] Svenska Kraftnat, *The Swedish Electricity Market and the Role of Svenska Kraftnat*, www.svk.se/web/Page.aspx?id=5843, p 9.

C References and Literature

Literature

Arellano, M.S., *Diagnosing and Mitigating Market Power in Chile's Electricity Industry*, http://www.web.mit.edu/ceepr/www/2003-010.pdf, 2003.

Barrera, F. and J. Crespo, *Security of Supply: What Role Can Capacity Markets Play?,* Research Symposium European Electricity Markets, September 2003.

Bates et al, *Bulk Electricity Pricing in Restructured Markets*, IEN Occasional Paper No 10, February 1997.

Blanlot, V., *Electricity Sector y Chile: A View on Main Problems and Achievements,* www.iabd.org/sds/doc/1822eng.pdf, 1994.

Botterud, A. and Magnus Korpås, *Modelling of power generation investment incentives under uncertainty in liberalised electricity markets*, www.saee.ch/saee2004/botterud.pdf, 2004.

Chakravarty, McConnell, *An analysis of prices, bid/ask spreads, and bid and ask depths surrounding Ivan Boesky's illegal trading in Carnation's stock*, Financial Management (Financial Management Association), Summer, 1997.

Chakravarty, Sarkar, *Liquidity in U.S. fixed income markets: a comparison of the bid-ask spread in corporate, government and municipal bond markets*, Federal Reserve Bank of New York Staff Reports 73 http://ideas.repec.org/p/fip/fednsr/73.html.

Cramton, P. & S. Stoft, *The Convergence of Market Designs for Adequate Generating Capacity*, http://www.gsb.stanford.edu/facseminars/events/economics/pdfs2006/2006_03-22_Cramton_final.pdf, 2006.

Fischer, R. and A. Galetovic, *Regulatory Governance and Chile's 1998-1999 Electricity Shortage*, info.worldbank.org/etools/docs/library/64592/2704.pdf.

Galetovic A. and L. Mello, *Strengthening Regulation in Chile: The Case of Network Industries*, OECD Economics Department Working Papers No.455, October 2005.

Harvard Electricity Policy Group, Special Session: Transition, A Never-Ending Process, The Mansion on Turtle Creek, Dallas, Texas, Thursday, at http://www.ksg.harvard.edu/hepg/Seminar%20Summaries/0300summ.pdf , March 16, 2000.

Hogan, W., *On an "Energy Only" Electricity Market Design for Resource Adequacy*, September 2005, http://ksghome.harvard.edu/~whogan/Hogan_Energy_Only_092305.pdf, September 2005.

Hogan, W., *Reliability and Scarcity Pricing: Operating Reserve Demand Curves*, Harvard Electricity

Policy Group, www.ksg.harvard.edu, March 2006.

Jacobson et al, "*Electricity De-regulation in California and Input Market Distortions*", Stanford Institute for Economic Policy Research, January 2004

Joskow, P., *Supply Security in Competitive Electricity and Natural Gas Markets*, http://econ-www.mit.edu/faculty/download_pdf.php?id=1270. 2005.

Joskow, P., *The difficult transition to competitive electricity markets in the U.S.*, Working Paper, The Cambridge-MIT Institute Electricity Project, CMI 28, 2003.

Littlechild, S., *Smaller Suppliers in the UK Domestic Electricity Market: Experience, Concerns and Policy Recommendations*, www.ksg.harvard.edu, June 2005.

Oren, *Capacity Payments and Supply Adequacy in Competitive Electricity Markets*, www.pserc.wisc.edu/ecow/get/publicatio/2000public/oren_capacity_payment.pdf, 2000.

Pollitt, M., *Electricity Reform in Chile – Lessons for Developing Countries*, www.mit.edu/ceepr/www/2004-016.pdf, 2005.

Roques, F., Newbery, D. and W. Nuttal, *Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA*, www.econ.cam.ac.uk/electricity/publications/wp/ep58/pdf, 2004.

Rosellón, J., *Different Approaches to Supply Adequacy in Electricity Markets*, Centro de Investigación y Docencia Económicas (CIDE) and Harvard University, 2004.

Rudnick, H. and Juan-Pablo Montero, *Second Generation Reforms In Latin America And The California Paradigm*, Pontificia Universidad Católica de Chile, December 2001.

Vignolo, M., *The Influence of Market Regulations in the Development of Distributed Generation*, paper at http://iie.fing.edu.uy/investigacion/grupos/syspot/InfReg_DG.pdf.

Vignolo, M., *The New Electricity Supply Industry in Argentina and Chile*, http://iie.fing.edu.uy, 2000.

Watts et al, *Second Generation Reforms In Chile, Power Exchange Model, The Solution*, Department of Electrical Engineering, Universidad Católica de Chile, 2002.

Woo et al, *Costs of Electricity De-regulation*, Hong Kong Energy Studies Centre, November 2004.

References

American Public Power Association, *Restructuring at the Cross-Roads, FERC Electricity Policy Reconsidered,* www.appanet.org, 2004.

AUSCID, *Submission to the Government of Western Australia, Electricity Reform Task Force*, www.auscid.org.au, January 2002.

Chris Dodd, United States Senator for Connecticut, "*Connecticut Delegation Urges FERC to Defer LICAP*", September 20 2005, http://dodd.senate.gov/index.php?q=node/3079

Complete Coalition, *The Case for ISOs and RTO's*, www.competecoalition.com/IRCstats.pdf.

CRA, *Real Time Pricing in California*, 8 January 2002, http://ciee.ucop.edu

CRA, *Review of the Electricity Market Model*, Report to WA Electricity Task Force, www.crai.com, April 2003.

Economist Intelligence Unit, *Chile economy: Heading for an energy crisis?*, www.viewswire.com, 8 March 2006.

Energy Forum, Current of discontent on Nord Pool, www.energyforum.net/featur/feat28.shtml, 2006.

ERAA, "*Submission to Review of VOLL*", letter dated 9 February 2004, http://www.eraa.com.au

Energy Security Analysis, *Final Report to Edison Electric Institute, Hedging Instruments in US Power Markets, Overview of Liquidity and Gap Analysis*, 21 September 2001.

Federal Energy Regulatory Commission, *Electricity Market Design and Structure*, Docket No. RM 01-12-00, ksgwww.harvard.edu/hepg/Papers/Henney_transco_FERC_sub_1-7-02.pdf, 2002.

Federal Energy Regulatory Commission, *Explanatory Statement In Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues, Devon Power LLC, et al.*, Docket Nos. ER0~t-563-000, -030, and -055, www.ferc.gov, March 2006.

Federal Energy Regulatory Commission, *Interim Order Regarding Settlement Procedures And Directing Compliance Filing*, Docket No ER03-563- 030, www.ferc.gov/EventCalendar/Files/20051021144736-ER03-563-030a.pdf , October 2005.

Fossil Energy International, *An Energy Overview of Chile*, www.geni.org/globalenergy/library/national_energy_grid/chile, 2002.

Futures and Options Association, *New Project to Address Falling UK Power Market Liquidity*, www.foa.co.uk, April 2006.

Hagman Energy AB, *Survey of system responsibility in the Nordic Countries*, www.nordel.org/Content/Default.asp?PageID=129, 2005.

Independent Market Operator, *Reserve Capacity Outcome*, www.imowa.com.au, October 2005.

Independent Market Operator, *Whole Electricity Market Design Summary*, www.imowa.com.au, October 2004.

International Energy Agency, *Power Generation Investment in Electricity Markets*, www.iea.org/textbase/nppdf/free/2000/powergeneration_2003.pdf, 2003.

ISO New England, *Annual Markets Report*, 2004.

ISO New England, *Capacity Settlement Summary*, www.iso-ne.com/pubs/whtpprs/capacity_settlement_summary.pdf, March 2006

ISO New England, *Letter to Honorable Members of Connecticut's Congressional Delegation*, www.iso-ne.com/pubs/pubcomm/corr/2005/ct_delegation_letter_8_24_05.pdf, August 24 2005.

ISO New England, *Letter to US Department of Energy*, www.electricity.doe.gov/document/isonewengland.pdf, 2005.

ISO New England, *Power Generation and Fuel Diversity in New England, Ensuring Power System Diversit*y, www.mtpc.org/renewableenergy/public_policy/DG/resources/2005-08-25_iso-ne_diversity-reliability.pdf, August 2005.

ISO New England, *Market Presentation*, http://www.nhiof.org/workshops/atcpresentations.

ISO New England, *Planning Procedure no. 3, Reliability Standards For The New England Area Bulk Power Supply System*, February 1, 2005.

ISO New England, *Wholesale Energy Market Course (WEM 1010)*, www.iso-ne.com.

ISO New England, *Wholesale Markets Plan*, www.iso-ne.com, 2006.

Melbourne Age, Rob Myers, Triple Electricity Price Cap Report, January 15 2004

National Grid, *Report to the Authority for the Gas and Electricity Markets, 2004/05*, www.nationalgrid.com.uk, 2005.

NECA, *Capacity Mechanisms, The Options*, www.neca.com.au, 2002.

NECA, *VoLL and the cumulative price threshold, Issues paper*, www.neca.com.au, 2003.

New England Conference of Public Utility Commissioners, *Horizontal Market Power in New England Electricity Markets: Simulation Results and a Review of NEPOOL's Analysis*, www.synapse-energy.com/Downloads/SynapseReport.1997, 1997.

Nordel, *Annual Report 2004*, www.nordel.org, 2005.

Nordel, *Peak Production Capability and Peak Load in the Nordic Electricity Market*, www.nordel.org, 2004.

Nordel, *Status of Nordel's work on Enhancing Efficient Functioning of the Nordic Electricity Market*, www.nordel.org/Content/Default.asp?PageID=129, April 2006.

Norden, *Coordination of network operations and system responsibility in the Nordic electricity market*, www.nordel.org/Content/Default.asp?PageID=129, 2006.

Nord Pool, *Annual Report 2004*, www.nordpool.com/information/publications, 2005.

Nord Pool, *Continuous trading at Nord Pool Spot's Elbas market*, www.nordpool.com/nordpool/spot/index.html

Nord Pool, *Trade at Nord Pool's Financial Market*, www.nordpool.com/nordpool/financial/index.html

Nord Pool, *Trading and settlement at Nord Pool Spot's Elspot Market*, www.nordpool.com.

Norwegian Water Resources and Energy Directorate, *Report on Regulation and Electricity Market*, www.ergeg.org/portal/page/portal/ERGEC_HOME/ERGEG_DOC/NATIONAL_REPORTS, 2005.

OECD Policy Brief, *Economic Survey of Chile*, www,oecd.org/publications/policybriefs ,2003.

Ofgem, *Ofgem's submission to the European Commission (DG TREN) Report*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG _DOCS/NATIONAL_REPORTS, 2005.

Ofgem, *Update: Securing Britain's electricity supply*, www.ofgem.gov.uk, December 2003.

Power Bill and Regulation of the Electric Sector, Libertad Desarrollo, No. 663, January 30, 2004.

Power in Europe, *Nord Pool Market Review*, Issue 465-466, 19 December 2005.

RWE, *An energy exchange for the UK*, www.rwe.com, 10 April 2006.

Stoft, S,. *Testimony on behalf of ISO New England on LICAP*, submitted to FERC, Docket Number ER-03-563-030, www.ferc.gov, August 2003.

Svenska Kraftnat, *Annual Report 2004*, www.svk.se.

Svenska Kraftnat, *The Black-out in southern Sweden and eastern Denmark, September 2003*, www.svk.se/upload/3813IEEE_engleskpresentation_jul2003_2230.pdf, November 2003.

Svenska Kraftnat, *The Swedish Electricity Market and the Role of Svenska Kraftnat*, www.svk.se/web/Page.aspx?id=5843.

Swedish Energy Markets Inspectorate, *Annual Report to the European Commission*, www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS, 2005.

Transmission and Distribution World, "FERC Defers LICAP in New England Region, Orders Hearing on Key Issues", January 7 2004, http://tdworld.com/news/FERC-defers-LICAP/

United States Department of Energy, "*Electricity Reform Abroad and US Investment*", http://www.eia.doe.gov/emeu/pgem/electric/ch2l2.html

United States Department of Energy, "*A Review of Market Monitoring Activities at U.S. Independent System Operators*", January 2004, http://www.electricity.doe.gov

Key Websites

Catholic University of Chile: www.ing.puc.cl/~power/southamerica/southamerica.htm

Chilectra: www.chilectra.cl/

Comisión Nacional de Energía (CNE): www.cne.cl/

Enersis: www.enersis.com/

Federal Energy Regulatory Commission: www.ferc.gov

Gener: www.chilgener.com/

Independent Market Operator WA: www.imowa.gov.wa

ISO New England: www.iso-ne.com

National Grid: www.nationalgrid.com.uk

Nordel: www.nordel.org

Nord Pool: www.nordpool.com

Office of Energy WA: www.eriu.energy.wa.gov.au

Ofgem: www.ofgem.gov.uk

Superintendencia de Electricidad y Combustibles (SEC): http://www.sec.cl/

Svenska Kraftnat: www.svk.se

Energy Retailers Association of Australia

Retail Price Regulation

Policy Position Paper

Issued June 2005

Introduction

In Australia, Governments have made significant progress in implementing electricity and gas market reforms. Nearly all jurisdictions have now implemented full retail contestability or committed to a timetable to do so. In some jurisdictions, the energy markets have now been open to full retail competition for over three years.

At the time competition was introduced at the retail level, Governments and regulators expressed a desire to also provide safety net arrangements in the form of transitional price controls for customers who were not able to, or chose not to, participate in the competitive market. The price controls were introduced as a transitional measure and were intended to prevent the abuse of monopoly power by gas and electricity suppliers, by imposing a regulatory discipline as a proxy for market discipline. The presumption was that competition provides the most efficient outcome, which will ensure an acceptable level of customer price protection. Accordingly, it was expected that retail price controls would be removed once competition was established. (See Appendix 1)

Jurisdictional regulators have retained retail price controls for certain customers in electricity and gas in markets that are now open to competition. Retail price regulation appears to be directed at protecting customers in genuine hardship and those who choose not to participate in the competitive market, resulting in a distortion of competition.

Governments continue to allow energy policy to be used to deliver social welfare outcomes. The ERAA believes welfare policy objectives are better addressed through a suite of programs targeted to provide direct and transparent payments to those in genuine hardship.

The ERAA strongly supports arrangements to protect customers in genuine financial hardship but does not support the use of price regulation as a means to do this. In retaining price regulation, governments and jurisdictional regulators are stifling competition and thus preventing the full benefits of competition from being realised.

Current Price Regulation

Gas pricing in the ACT is the only gas market which has become unregulated. The ERAA hopes this precedent will be extended to other jurisdictions when the current price paths lapse.

Table 1: Jurisdictional price paths to 2007 and beyond:

Jurisdiction/fuel	**Period**
NSW electricity and gas	30 June 2007
Victoria electricity and gas	31 December 2007
ACT electricity	30 June 2006
ACT gas	No price regulation beyond June 2004
SA electricity	31 December 2007
SA gas	Expected until 30 June 2008
The MCE agreed that the Australian Energy Regulator will be responsible for the regulation of distribution and retailing (other than retail pricing), following development of an agreed national framework - Ministerial Council on Energy Report to COAG on Reform of Energy Markets – 11 December 2003.	

Governments can and should strengthen competition in jurisdictional markets by identifying and removing any remaining barriers to effective competition. The ERAA advocates the removal of price caps as a barrier to competition and price regulation should not be extended beyond the current price paths established by jurisdictions.

Position Summary

The ERAA's position is that:

- Prices in a competitive market should not be regulated. Price regulation is inefficient, stifles price and service competition, stifles product innovation and prevents the full benefits of competition from being realised.

- Retail price regulation for electricity and gas should be phased out and more targeted programs for assisting customers in financial hardship should be implemented.

- Similarly, default pricing as a safety net for customers choosing not to participate in the competitive market should only be a transitional measure. General consumer protection laws provide sufficient protection for energy consumers against unfair practices by retailers such as unreasonably high energy prices.

- Price regulation should not be extended beyond current price paths. In the time prior to the expiry of these periods governments should identify and remove any market failures or dysfunctions.

- The responsibility for retail price regulation should remain with the jurisdictions until such time as it is removed.

Rationale for the Removal of Retail Price Regulation

Benefits of unregulated pricing

Removal of retail price regulation will:

- Promote competition in the electricity and gas markets and increase the overall efficiency of the energy industry.
- Expedite the achievement of more cost-reflective pricing. Cost reflective pricing will lead to a more efficient use of resources, and:
  - allow cross-subsidies to be unwound;
  - provide greater incentives for the promotion of energy efficiency;
  - provide price signals to encourage demand management;
  - reduce the need for new investment in generation capacity and transmission and distribution networks;

  - increase penetration of renewable energy technologies where economic; and
  - support initiatives to reduce greenhouse gas emissions.
- Promote investment in supply and demand side initiatives enhancing the security and reliability of energy supply;
- Remove barriers to entry for second-tier retailers;
- Avoid the need for future significant price increases for customers to facilitate future required investment in the energy market;
- Reduce significant regulatory costs of complex and intrusive price reviews; and
- Create an incentive to implement a more targeted and effective mechanism for assisting vulnerable customers.

Economic efficiency

The ERAA believes that market forces lead to the most efficient use of resources in all but exceptional circumstances – ie where market failure results in less efficient outcomes than might otherwise be possible. Ongoing price regulation of retail energy is stifling competition, particularly where tariffs have been set below cost-reflective levels, creating a barrier for new entrants.

Price regulation, with its inherent cross-subsidies, distorts efficient market outcomes and prevents appropriate price signals reaching customers. Such price signals otherwise influence customer behaviour and consumption. The Parer Review[1] noted that retail price caps prevent flexible and innovative pricing structures and impede demand side response. Price controls (and side constraints) prevent these innovations from developing, and thus frustrate the very objectives that governments are seeking from demand side response.

The Productivity Commission in its Inquiry Report on the Review of Competition Policy Reforms released in February 2005 recommended that once effective competition is established retail price controls be removed. Adequate, well-targeted and transparent community service obligations should be implemented to ensure that disadvantaged groups continue to have access to energy (refer Appendix 1).

When market competition sets retail prices for all customers more efficient outcomes will be realised in the market.

Customer protection

The ERAA believes the removal of price regulation will make way for more efficient pricing outcomes for customers. ERAA considers there is no justifiable link between price regulation and consumer protection, and it recognises that more targeted arrangements are required to assist customers in genuine financial hardship.

The ERAA strongly supports arrangements to protect customers in genuine financial hardship, however more effective policies are needed to address customers in hardship and continued price regulation is not part of the solution.

Customers with insufficient income need to be adequately supported with direct and transparent government subsidies through government welfare programs that are

[1] Towards a Truly National and Efficient Energy Market, COAG Independent Review of Energy Market Directions, December 2002, p.177

simple to administer and which would not interfere with the operation of the retail market. Energy retailers and community groups can assist governments in implementing such programs.

The combination of Government support and successful retailer vulnerable customer hardship programs will support competition in vulnerable customer segments and ensure programs are effective, transparent and efficient.

Default pricing has also been used by Governments to provide a safety net for customers choosing not to participate in the competitive market. It is the ERAA view that this should only be a transitional measure until such time as the market is shown to have effective competition and the customer has a variety of retailers to choose from.

It is well accepted that existing general consumer laws (consisting of State fair-trading legislation, the Commonwealth Trade Practices Act and common law) provide robust protection for consumers in other markets against unconscionable practices by retailers. It is the ERAA view that general consumer protection laws are similarly effective in the retail energy market to ensure that consumers are protected from unconscionable conduct in the form of unreasonably high energy prices.

Some jurisdictions have used retail price regulation as a mechanism for maintaining a level of pricing equity between customers in urban and regional areas. The ERAA believes that these customers should be assisted through transparent subsidies that do not distort the operation of the retail market and that assist in the facilitation of retail competition.

Effectiveness of Competition

The decision of governments in the mid 1990s to introduce competition into retail energy markets was based on the proposition that market based outcomes are the most effective and efficient way to deliver goods and services to customers. Retail prices in the energy market were regulated to prevent abuse of monopoly power by energy suppliers', thereby imposing a regulatory discipline as a proxy for market discipline.

With the introduction of competition in the energy market it is important that price controls are removed to allow prices to move to market-based prices, reflecting the costs and risks of supplying customers. Some jurisdictions and regulators have indicated a willingness to remove price regulation once it has been demonstrated that competition is sufficiently developed.

ERAA is concerned with the current assessment by regulators about what is considered sufficient levels of competition. It can be seen from the results of an IPART survey[2] released in December 2004 that a high level of customers (74 percent) were aware that they can choose their gas or electricity supplier and that the main reason for changing supplier was that the competitive offer was cheaper. The main reason given for not changing (gas or electricity) supplier was that the customer was happy with their current supplier. The conclusion to be drawn from this is that customers have made a conscious choice and this is what should be measured.

[2] Residential energy use in Sydney, the Blue Mountains and Illawarra, Results from the 2003 household survey. Independent Pricing and Regulatory Tribunal of New South Wales, Research Paper RP27, December 2004, at p.35

This finding highlights the ERAA's concern that indicators of effective competition chosen by regulators may not actually reflect the effectiveness of competition. For example, some regulators are presuming that a high churn rate indicates competition is more effective than a low churn rate (which can and does arise where customers are satisfied with their existing supplier). Whilst a high churn rate may reflect effective competition a low churn rate does not necessarily indicate a lack of effective competition or market failure/dysfunction. A better indicator might be the number of market offers made to customers or customers indicating that they have made a conscious and informed choice to either churn or remain with their current retailer.

The seeking of positive confirmation that competition is effective is a flawed process and one which is unlikely to result in a level of satisfaction that will justify the decision to remove retail price regulation

The ERAA is strongly of the view that rather than placing the onus of proving that there is effective competition on the industry, jurisdictional regulators and governments should be focusing on the identification and removal of factors causing market failures and dysfunctions, thereby focusing on correction of the market rather than increasing the level and extent of regulation.

The ERAA believes that to rely upon evidence to suggest that competition exists or is sufficiently developed in the energy market, before discontinuing price regulation is somewhat of a paradox. Price regulation is a key impediment to effective competition as market forces should determine prices.

Difficulty in regulating prices

Aside from the fact that price regulation impedes the development of a competitive market, there is the added difficulty associated with determining an appropriate regulated price. This difficulty was articulated by the United Kingdom (UK) regulator Ofgem following its review of gas and electricity competition and supply price regulation[3]. On the option of continued price caps for suppliers Ofgem commented that:

> *"Ofgem considers that this option has a number of identified regulatory risks that could unjustifiably prevent or distort competition to the detriment of customers' interests."*

In a 2003 press release[4] Ofgem's Chief Executive Callum McCarthy stated that:

> *"… All the evidence suggests price competition is a key driver of consumer choice. To artificially set one price for all customers would kill competition, as well as stopping those who shop around from getting better deals. It would also remove the competitive pressure on prices for those customers who remain with their traditional supplier."*

Ofgem concluded that price controls would do more harm than good in a competitive market and as a result took the decision to remove price controls from April 2002 following four years of full retail contestability in gas and three years of full retail contestability in electricity.

[3] Review of domestic gas and electricity competition and supply price regulation, Conclusions and final proposals, February 2002

[4] Ofgem Press Release "Vigorous Competition for domestic customers, but Ofgem remains vigilant" – 16 June 2003

The ERAA's position on regulation of retail prices in competitive markets is reinforced by the view taken by the UK regulator Ofgem[5] with respect to its objectives:

> *"Protecting Customers*
>
> *Everything Ofgem does is designed to protect and advance the interests of consumers present and future.*
>
> *Ofgem does this by:*
>
> - *Promoting effective competition, wherever appropriate;*
> - *Regulating only where necessary; and*
> - *Ensuring that special help is targeted to vulnerable customers."*

In February 2005, the South Australian energy regulator, Lew Owens, stated he would like to remove price caps in the FRC environment as:

> *"It is an impossibly difficult task to set caps over a long period. 'This is particularly the case where summer peak loads have a major impact on costs and where tariffs cannot adequately reflect the price variations', he says."*[6]

Cost-reflective tariffs

ERAA advocates a light-handed regulatory approach to setting regulated prices. Whilst price regulation remains in the energy market, tariffs should be set at cost-reflective levels to promote competition by encouraging customers to transfer to market contracts, thus allowing for easy removal of price regulation at the end of the transition period. The setting of regulated tariffs below cost stifles competition and acts as a barrier to new market entrants.

MCE Reforms, AER and pricing

The Ministerial Council on Energy is currently implementing wide-ranging energy market reforms. A new national regulator, the Australian Energy Regulator (AER), has been established and a new national distribution and retail regulatory framework will be implemented from 2006.

In settling the future retail regulatory framework, the ERAA does not support the transfer of retail price regulation to the AER. The ERAA further believes that the current price paths should be left to run their course and then cease.

[5] Protecting Customers 11/12/2002, Ofgem main page www.ofgem.gov.uk
[6] esaa Energy Supply Magazine, February 2005, p9

APPENDIX 1

GOVERNMENT AND REGULATORS VIEWS ON PRICE REGULATION IN A COMPETITIVE MARKET

Regulators recognise that safety net arrangements are transitional measures and that they will become unnecessary when effective competition is achieved in the energy market(s):

The Office of Gas and Electricity Markets (UK)

Callum McCarthy, CEO, press release 16 June 2003:

> *"All evidence suggests that price competition is the key driver of customer choice. To artificially set one price for all customers would kill competition, as well as stopping those who shop around from getting better deals. It would also remove competitive pressures on prices for those customers who remain with their traditional supplier."*

The Independent Pricing and Regulatory Tribunal of NSW

The Independent Pricing and Regulatory Tribunal of NSW, Issues Paper – Review of Gas and Electricity Regulated Retail Tariffs, October 2003 (p.4):

> *"Extending choice and competition to all retail customers is predicated on the principle that an efficient, competitive market can deliver benefits for customers in terms of both price and quality of service."*

The Essential Services Commission of Victoria

The Essential Services Commission of Victoria, Special Investigation: Review of the Effectiveness of Full Retail Competition for Electricity — Final Report, September 2002 (p.18):

> *"Competition is not an end in itself, but a means of achieving more efficient use of the community's resources in the production, supply and consumption of goods and services. Effective competition contributes to this objective by forcing businesses to produce at least cost, to charge cost-based prices and to be innovative in product and process design and in service delivery. In a competitive market place failure to operate in these ways would simply result in loss of sales to more efficient competitors supplying substitute goods and services at the prices and quality preferred by consumers.*
>
> *For these reasons promoting effective competition is also an efficient means of protecting final customers from the misuse of market power, compared to other more interventionist regulatory approaches."*

The Office of the Regulator General Victoria, Approach to Benchmarking Electricity Retail Costs – Issues Paper, November 2001 (p.4):

> *"Once retail competition is judged to be effective, the assessment of standing offer tariffs can be less intrusive, since the presence of competition will itself provide protection for consumers."*

The Essential Services Commission of South Australia

The Essential Services Commission of South Australia – Monitoring The Development of Electricity Retail Competition in South Australia - Proposed Approach, ESCOSA, April 2003 (p.22):

> *"The introduction of full contestability to the retail electricity market was a policy decision implemented by successive South Australian Governments. Underpinning this policy decision is a view that it is the process of competition, rather than regulation, which can, ultimately, deliver maximum benefits to consumers through lower prices, better goods and services and increased efficiency. Competition, it is argued, provides these outcomes in a more expeditious and efficient manner than does direct intervention into a market by a Government.*

The Essential Services Commission of South Australia – Monitoring The Development of Electricity Retail Competition in South Australia - Proposed Approach, ESCOSA, April 2003 (p.1):

> *"If ESCOSA is to protect the long term interests of South Australian consumers, and given that the electricity retail market in South Australia is now based on the concept that competition will ultimately provide the best protection for consumers, then it is important for ESCOSA to monitor the state of competition in the South Australian electricity retail market."*

The Independent Competition and Regulatory Commission of the ACT

The Independent Competition and Regulatory Commission of the ACT, Final Determination, Review of natural gas prices, May 2001 (p.8):

> *"Once effective competition is established, market forces should ensure that suppliers provide services of quality demanded by customers, and that they do not earn excessive profits."*

NSW Government

The Ministry of Energy and Utilities, New South Wales Policy Framework to Support Full Retail Competition in Gas, 21 December 2000:

> *"Therefore, an appropriate level of retail price regulation is required to protect residential and small business customers until there are sufficient competitive pressures in the gas retail market."*

NSW Treasury – Electricity Reform Statement, May 1995 at item 2.6, page 20:

> *"In the initial period of the market's operation, continued formal oversight of retail prices which are currently subject to cross subsidy will be required. In addition, it will be desirable for all retail prices to be subject to careful monitoring until such time as the market is shown to be operating effectively".*

Retail Competition in Electricity Supply, Treasury Policy Paper TPP96-1, June 1996, at page 23

> *"Historically, customers have paid a "total" price for delivered electricity…..In a fully competitive market, only the transportation will be regulated. The energy price and any retail charge not included in the energy price will be competitively determined".*

The Productivity Commission

"Community Service Obligations (CSOs) are government requirements for service providers to engage in non-commercial activities to meet affordability and access objectives."

….all governments have adopted a commonly agreed definition of CSOs and have accepted the principle that costs of CSOs should be transparent and funded directly from consolidated revenue."

<u>PC Recommendation 10.5</u>

"In retail infrastructure markets, once effective competition has been established, regulatory constraints on prices should be removed. Ensuring that disadvantaged groups continue to have adequate access to services at affordable prices should be pursued through adequate, well targeted and transparent community service obligations (or other appropriate mechanisms), that are monitored regularly for effectiveness."

Productivity Commission Inquiry Report: Review of Competition Policy Reforms, February 2005.