30 June 2006

Mr Ian C Woodward
The Reliability Panel
Australian Energy Market Commission
PO Box H166
Australia Square, NSW 1215

By email: panel@aemc.gov.au

Dear Mr Woodward,

Comprehensive Reliability Review

We refer to the abovementioned review and the Issues Paper dated May 2006.

NewGen Power is pleased to attach its submission in response to the review. Note that due to the comparatively tight timeframes associated with the process, it has been necessary for NewGen Power to focus its response on areas of key interest to our business, viz., the wholesale market and its impact on the economics and timely arrival of new entrant plant.

By way of brief background, NewGen Power is a newly formed merchant generator owned by Babcock & Brown and the ERM Group. Our first 450MW gas fired peaking plant is currently being commissioned in South West Queensland. Additionally, we have a 320MW combined cycle gas turbine plant under construction at Kwinana in Western Australia – the latter plant thus exposing us to a different market structure which incorporates a capacity market as well as an energy market. We are also nearing the financial closure of a 600MW peaking plant at Uranquinty, near Wagga Wagga in New South Wales.

Should you have any queries in relation to our submission, I can be contacted on 07 3327 1200.

Yours faithfully,

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Question 1: Is there now, or is there likely to be in the future, a problem with supply reliability in the NEM?

While thus far the NEM seems to have delivered reliable supplies, as Peluchon (2003) has noted in the case of Europe, this is because newly deregulated energy-only markets have largely thrived on generation over-capacity built up by the public monopolies that previously existed. In the case of the NEM, this came in the form of a substantial over-investment in base plant in New South Wales and Victoria.

Compounding the oversupply inherited at the onset of reforms was the *"excess entry result"* that occurred in Queensland. At the start of the NEM in 1998, spot prices in the Queensland region rose to extreme levels due to delays in the interconnection of the Queensland and New South Wales power systems. The spot prices that subsequently emerged in Queensland immediately after the reforms commenced were so lucrative due to inadequate supplies of baseload plant that the outcome was literally an *"excess entry result"* of multiple, low cost, coal-fired, new entrant generators (Simshauser, 2001; 2006). This in turn delivered vast oversupplies of base plant and thus further bolstered the oversupply of pre-NEM capacity. This had the effect of further delaying the inevitable balancing of post-reform supply and demand at the aggregate level.

But most of the oversupply outlined above has been absorbed at the aggregate level, and there is an issue as to whether adequate supplies will be installed in a timely manner in the future. Certainly, this is a well-known concern of the Queensland Government, and presumably a possibility not ignored by other jurisdictions. Thus, a serious issue that faces the deregulated NEM is whether the energy-only price mechanism is capable of signalling for new plant in a timely manner, and in line with societal (and therefore political) expectations.

Our organisation would argue that the financial conditions necessary for new plant entry *lag, by some years,* the requirements that would otherwise emerge from a physical analysis of the power system (given a reliability constraint).

To illustrate the issues argued above, consider the following analysis of the NEM's history and subsequent investment activity. To start with, the optimal mix of plant in 1997/98 (just prior to NEM start) against the actual supply is provided in Table 1, the the optimal mix of plant determined using the cost data contained in Table 4 (which is presented later, on page 5).

Table 1: Supply-side portfolio in the NEM in 1997/98

NEM 1997/98	Optimal (MW)	Actual (MW)	Portfolio balance (MW)
Baseload	20,400	24,500	4,100 *overweight*
Intermediate	2,000	2,100	100 *overweight*
Peaking	8,100	6,600	-1,500 *underweight*
Total	30,500	33,200	2,700 *oversupplied*

Note that during 1997/98, the NEM power system, incorporating the States of Queensland, New South Wales, Victoria and South Australia, was oversupplied by approximately 2700MW, with baseload plant being overweight by 4100MW.

Growth in electricity demand has been substantial since then. And the supply side has generally kept apace, albeit not entirely through merchant means. A number of new machines have been facilitated through Government mechanisms (e.g. PPAs), and as noted earlier, via an *"excess entry result"* in the Queensland region. Table 2 provides a listing of the new entrant plant.

Table 2: List of new entrant plant in the NEM

Entrants	Year	Region	Ownership	SCpf (MW)	NGCC (MW)	OCGT (MW)
Roma GT	1999	QLD	Private			80
Swanbank D GT	1999	QLD	Public			34
Oakey GT	2000	QLD	Private PPA			282
Ladbroke Grove GT	2000	SA	Private			80
Pelican Point CCGT	2000	SA	Private		478	
Port Lincoln GT	2000	SA	Private			50
Callide C	2001	QLD	50% Private	840		
Redbank	2001	NSW	Private PPA	150		
Bairnsdale GT	2001	VIC	Private			92
Quarantine GT	2002	SA	Private			96
Swanbank E CCGT	2002	QLD	Public		376	
Millmerran	2002	QLD	Private	840		
Tarong North	2002	QLD	50% Private PPA	443		
Valley Power GT	2002	VIC	Private			300
Somerton GT	2002	VIC	Private			160
Hallet GT	2002	SA	Private			183
Yabulu CCGT	2004	QLD	Private PPA		247	
TOTAL (MW)	4,731			2,273	1,101	1,357
Required (MW)	4,200			0*	400	3,800
Surplus/Deficit (MW)	531			2,273	701	-2,443
INVESTMENT ($M)	5,583			3,410	1,156	1,018

*New base plant would be required in 2005/06.

But as Table 3 below notes, when the new entrant plant in Table 2 is added to the pre-NEM plant stock contained in Table 1, and demand statistics updated to reflect most recent load conditions, supply and demand in the NEM is now almost in balance at the aggregate level. And somewhat alarmingly, the structure of the supply-side is now showing a growing deficit of peaking plant, which must by its very nature cast some question as to whether supply will remain reliable in the future:

Table 3: Supply-side portfolio in the NEM in 2004/05

NEM 2004/05	Optimal (MW)	Actual (MW)	Portfolio balance (MW)	
Baseload	23,300	26,700	3,400	*overweight*
Intermediate	2,300	3,200	900	*overweight*
Peaking	11,900	8,000	-3,900	*underweight*
Total	37,500	37,900	400	*oversupplied*

The 400MW of excess capacity highlighted in Table 3 will be exhausted over the course of the coming year. And that peaking plant has shifted from *1500MW underweight* in 1997/98 (see Table 1) to *3900MW underweight* in 2004/05 (see Table 3) in a climate of rising peak loads, limited demand for long-dated hedging and increasing Vertical Integration – should be deeply concerning to Consumers, Retailers, State Governments, Energy Regulators and Policy Makers alike.

The investment frenzy that occurred in Queensland is unlikely to be repeated at such levels in the future – since the financial consequences of substantial oversupply is now well known to equity participants and more importantly, to the lenders of debt finance.

The issue here is that (1) the NEM commenced its life with an excellent and oversupplied stock of utility built plant; and (2) Queensland gave a substantial boost to that plant stock via a unique set of circumstances that is unlikely to be repeated; and (3) a number of new plant were facilitated by Governments, which again will not (or should not) be repeated.

Such circumstances are not unusual in emerging, energy-only, deregulated electricity markets. But as other countries are finding, these conditions will ultimately be exhausted and at that point, the “reform honey-moon” is over, and the market is then required to stand on its own feet and deliver new plant on a timely basis – or risk continual intervention by (understandably) concerned political forces. The trend of declining peaking plant in Tables 1 and 3 provides some evidence that such intervention is a plausible scenario – given that peaking plant as a class is, by its very definition, the technology that ultimately delivers reliability of supply.

Question 2: If yes, is there now, or is there likely to be in the future, a problem with the reliability settings?

The reliability settings, in terms of unserved energy, are appropriate for our society, and any relaxation of the current setting is likely to be intolerable from a political perspective. But NewGen Power would question whether a single unserved energy measure is entirely appropriate. As Booth (2005, pp. 4-5) has noted:

> *Reliability standards used by the States prior to NEM start resulted in planned reserve plant margins (over peak load expressed with a 50% Probability of Exceedance or 50% PoE) of 20-25% on a long term basis, within which ample scope existed for operational reserves. Probabilistic studies based on random outage events were tempered by the testing of the resulting reserve plant margins against a variety of contingencies to ensure that the result was socially and politically acceptable. The utilities did not rely only on the results of*

> *probabilistic studies or on one single criterion… NEMMCo relies on the results of Monte Carlo based probabilistic studies and the results are not tested against a range of possible multiple dependent outages… Actual reserve margins experienced in the NEM have been much higher (28%+) than the minimums set by NEMMCo both for the NEM as a whole and for the individual States… the acceptability of the Standard by the public and politicians has yet to be seriously tested…*

Monte Carlo simulation modelling is indeed an elegant way in which to test a proposition. But what represents a credible scenario from a statistical perspective, and how the system actually behaves, are invariably quite different. The AEMC Issues Paper acknowledges this on Page 30.

Additionally, the current unserved energy and VoLL setting provide an intractable equilibrium for an energy-only market. Generators bidding competitively, with a $10,000 VoLL and a reliability constraint, cannot possibly lead to the recovery of reasonable costs. Thus, not only is the energy-only NEM inherently unstable, it does not have a 'defined equilibrium'.[1] To demonstrate that this is the case with the energy-only NEM, consider the following quantitative analysis of the NEM:

It is first necessary to make certain assumptions about the values of existing plant and new entrant plant. For the purposes of this submission, it is sufficient to assume that the cost of all existing and new entrant plant in the NEM reflects the form of the three optimum and most efficient generation technologies (in order to remove any inefficiencies that may exist with the existing plant stock) required to satisfy demand, given the resource endowments of east-coast Australia. These are:

- Super Critical pulverized fuel (SCpf) plant, which perform base load duties;
- Natural Gas Combined Cycle (NGCC) plant, which perform intermediate duties; and
- Open Cycle Gas Turbine (OCGT) plant, which perform peaking duties.

The cost assumptions for each technology are provided in Table 4. Note that the variable cost of production is calculated by multiplying the heat rate (kJ/MWh) by the unit fuel cost ($/GJ), then adding the variable operations and maintenance (O&M) cost. Unit clusters refers to the ideal plant configuration, given the assumptions surrounding Fixed O&M costs.

Table 4: New entrant generating plant costs

Generation technology	Capital cost ($/kW)	Unit size (MW)	Variable O&M ($/MWh)	Fixed O&M ($M pa)	Useful life (Yrs)	Heat rate (kJ/MWh)	Fuel cost ($/GJ)	Unit clusters (#)
SCpf	1,500	660	-	22.5	40	9,500	1.00	2
NGCC	1,050	375	2.50	4.5	30	7,100	3.25	1
OCGT	750	160	3.00	2.0	30	11,500	3.50	3
Cost of capital	11.00%							

Using the statistics outlined in Table 4, the average cost for a SCpf plant at a capacity factor of 90% per annum is around $34.50/MWh. NGCC plant has an average cost of around $42.25/MWh while the OCGT plant has an average cost of around $56.00/MWh – notwithstanding such comparison is entirely inappropriate given a system efficiency

[1] This of course assumes that new entry is considered desirable.

requirement for plant with varying load factors. The cost data contained in Table 4 and the 2004/05 half-hourly load curves for Queensland, New South Wales, Victoria & South Australia, and an aggregated NEM load curve have been entered into a dynamic partial equilibrium model called Nemesys in order to determine the cost minimising plant stock, the requirement for system reserves and the competitive spot price and aggregate system cost. The key outcomes from the simulation model have been reproduced in Table 5.

Table 5: Power system scenario results using 2004/05 load data under conditions of an optimal plant mix and perfect competition amongst generators

Statistics with VoLL at:	$10,000.00	QLD	NSW	VIC/SA	ΣSTATES	NEM
Electricity Load						*unconstrained*
Peak demand	(MW)	8,232	12,884	10,986	29,403	29,403
Energy demand	(GWh)	49,440	74,432	62,414	186,287	186,662
Load factor	(%)	69%	66%	65%	72%	72%
Generating Plant						
Base plant	(MW)	6,600	9,900	7,920	24,420	24,420
Intermediate	(MW)	750	1,125	1,125	3,000	2,250
Peak plant	(MW)	2,720	4,160	3,840	10,720	7,200
Aggregate	(MW)	10,070	15,185	12,885	38,140	33,870
System Reliability						
Lost load	(%)	0.001%	0.002%	0.002%	0.002%	0.002%
System Reserve	(%)	22%	18%	17%	30%	15%
System Price/Cost						
Competitive spot price	($/MWh)	27.32	26.79	23.69	25.89	28.24
System unit cost	($/MWh)	41.37	41.33	41.35	41.35	38.96
Implied loss	($/MWh)	-14.05	-14.54	-17.66	-15.46	-10.72
Cost recovery	(%)	66%	65%	57%	63%	72%
Financial Results						
Asset Value (market)	($M)	12,727.5	19,151.3	15,941.3	47,820.0	44,392.5
Merchant revenue	($M)	1,350.6	2,102.6	1,746.6	5,199.8	5,814.3
Fuel costs	($M)	519.0	781.1	669.8	1,969.9	1,938.6
O&M costs	($M)	274.8	413.2	342.5	1,030.4	972.4
Capital costs	($M)	1,251.5	1,883.3	1,568.4	4,703.3	4,361.2
Implied loss	($M)	-694.7	-974.9	-834.1	-2,503.8	-1,457.8
Economic Returns (benchmark return = 11%)						
Base load SCpf plant	(%)	7.3%	7.7%	7.8%	7.6%	8.9%
Intermediate NGCC plant	(%)	8.6%	8.2%	7.6%	8.1%	8.9%
Peaking OCGT plant	(%)	6.5%	6.3%	5.3%	6.0%	7.9%
Aggregate plant stock	(%)	7.3%	7.5%	7.4%	7.4%	8.8%

There are five model-output columns in Table 5. The first three columns list the regional markets of Queensland, New South Wales, and the joint Victoria-South Australia region. The next column titled ‘*ΣStates*’ is the arithmetic aggregate of the Queensland, New South Wales and Victoria-South Australia results. The final column titled *‘NEM’* assumes an *unconstrained* transmission system – that is, it is a scenario that describes what the power system *should* look like were it not for the grossly inadequate transmission regulations that exist in the NEM. The most important result from Table 5 is that despite the perfectly optimal and cost minimizing plant stock assumed, a stable equilibrium could not be reached in any region.

The model outputs in Table 5 start with information regarding electricity load, viz. peak demand, energy demand and the system load factor. Queensland has the highest regional load factor at 69%, with the aggregate NEM result highest at 72%, which is driven by the diversity of loads across Eastern Australia. Next in Table 5 is the Generating Plant statistics, which reflect the minimum cost solution given the load curve. Following this are the System Reliability statistics. The existing reliability panel of 0.002% was used and consequently, the plant mix was driven down to the point just short of violating this constraint, thereby minimizing the amount, and therefore cost, of plant; and maximizing the number of 'tolerable blackouts', and therefore the number of $10,000/MWh price spike events.

The next segment of Table 5, System Price/Cost, provides an important quantitative analysis of the energy-only NEM under competitive market conditions. The results demonstrate that there is no definable equilibrium in any region. Note in every case that the competitive spot price is markedly lower than system unit cost. Cost-recovery ratio's range between 57% - 72%. In theory, the system with the highest load factor should exhibit the lowest cost. But the lack of interconnector capacity can distort this outcome by requiring a higher reserve plant margin.

Despite this 'ideal' NEM market, generators still only recoup a percentage of fair costs. The cost recovery ratios rely critically on VoLL at $10,000/MWh. If, for example, VoLL was reduced to $5,000/MWh, the cost recovery ratio in the unconstrained NEM would reduce from 72% to 63%. The individual region results reduce by a similar margin.

The Financial Results segment of Table 5 provides a consolidated Profit & Loss Statement for the total generation portfolio by region. The losses reflect the gaps in the cost recovery ratio, and place a quantitative figure on the extent of the problem associated with energy-only markets. To be sure, the Merchant Revenue calculations in Table 5 were calculated by reference to energy and spot price. That is, there is no hedge contract income included in the determination of revenues. Prima facie, one may argue that the absence of hedge revenues constitutes an inherent floor in the analysis. However, such a criticism is too convenient. The power system analysis undertaken in Table 5 assumes a competitive market and the existence of the least-cost, optimal mix of plant. In consequence, the modeled clearing prices reflect the natural economic result and therefore the expected fair value of hedge contracts.[2] Any deviation in hedge contract values (i.e. above or below the modeled spot price outcome) would violate the assumption of a competitive market, would ignore the ability to arbitrage, and perhaps most significantly, would assume that electricity retailing is uncompetitive and that all retailers are inherently incompetent in trading forward hedge contracts. Yet even allowing these principles to be violated at the extreme, and assuming the existence of a $5.00/MWh spot-swap spread, such margins pale into insignificance by comparison to the $14.00 - $17.00 losses incurred by generators in Table 5.

The Economic Returns by generator class and by region provided in Table 5 confirm that against the benchmark result of 11%, no technology makes an adequate return, and

[2] These concepts merely reflect Fama's (1970) generally accepted 'Efficient Market Hypothesis'. The implication here is that electricity markets can be categorised as *semi-strong form efficient* as per the categories defined by Roberts (1967). For further details, see Brealey & Myers (1996), *Principles of Corporate Finance*, McGraw-Hill, Sydney.

peaking plant incurs the greatest losses. This, in large part, explains the deteriorating deficit in peaking plant as noted by the difference in results included in Tables 1 and 3 above.

In any event, the results in Table 5 confirm that there is no evidence that the NEM, or any of its regions, have a tractable equilibrium given a reliability constraint and a VoLL of $10,000. As Bidwell and Henney (2004, p.22) explain, for an energy-only market to be remunerative to all plant whilst remaining in a state of competitiveness, the power system would need to be *"near the edge of collapse"*. In a sensitivity study, the Nemesys Model indicated that for New South Wales generators to balance their books, blackouts would need to exceed the Reliability Panel's 0.002% threshold by 2½ times, which naturally occurs when system reserves are driven down from 18% to 13%.

Finally, the above analysis assumes a perfectly balanced plant stock. Yet the NEM is known to be overweight base plant. When base plant capacity excessively dominates the aggregate supply function in an energy-only gross pool market, these low-cost machines tend to cannibalise the important 'price-setting' role of higher marginal cost intermediate and peaking plant. Consequently, base plant capacity sets price too-low, too-often. And while a *physical system analysis* can clearly point to a near-term supply shortage, the economics of the energy-only market 'fails' in that the signaling for new plant occurs very suddenly, and without warning. This in turn will virtually ensure that peaking plant, when it does arrive, will do so "5-minutes after midnight".

Question 3: If yes, is it serious enough to cause material dislocation to suppliers and users in the future?

If the analysis presented in Questions 1 and 2 is accepted as reasonable, then it necessarily follows that material dislocation to users is predictable in the future. The question here is one of resource adequacy.

Note that it is not NewGen's contention that insufficient plant capacity will become an inherent problem in absolute terms. The issue here is one of timing. That is, will new plant arrive in a timely manner, and in a manner consistent with that envisaged by power system stakeholders.

In Eastern Australia, the average domestic consumer still considers electricity 'an essential service' rather than a tradable commodity. Considered in this light, an adequate reserve plant margin in an energy-only market is effectively an externality to electricity production and consumption. That is, consumers prefer adequate reserves but currently are not charged for capacity. And when a generator makes an investment which has the effect of providing additional reserves, they are inadequately remunerated unless market power is exercised. In fact, on the contrary, because generation plant investments are usually 'lumpy', post-entry spot and contract prices invariably fall below system cost (Simshauser, 2001). Under such conditions, Bidwell and Henney (2004, p. 11) have noted the logical conclusion:

> *…As is well known from standard economic text books, the presence of a large externality is one of the problems that a market cannot, by itself, deal with; and, if left alone, such an externality will be a predictable cause of market failure…*

Question 10: Is a measure based on unserved energy the most appropriate form of standard?;

Question 11: If not, what would be a more appropriate form of standard for use in the NEM and why?; and

Question 12: Is it desirable, and are there ways, to broaden the form of the standard to incorporate a range of reliability-related considerations? If so, which considerations and why?

As Booth (2005) has noted:

The present reliability standard was adopted in 1998, amid some controversy, and was said to be based generally on the reliability criteria used by the various States for planning purposes, but expressed as a level of "unserved energy". The reliability standard was established for short term operations reasons, and especially to allow the establishment of intervention levels for NEMMCo under the Reserve Trader arrangements. It can be argued that the NEM does not have a *Reliability Standard* in the normal sense of these words – that is a level of reliability which is socially and politically acceptable over the longer term. It can also be argued that the combination of the level of VOLL used in the NEM and the economics of peaking and intermediate plants, imply load shedding for 10 hours per year, every year, if adequate incentive for new plant investments is to exist. This frequency and extent of load shedding would be unacceptable to industry and the public for bulk power supply.

Reliability standards used by the States prior to the NEM start resulted in planned reserve plant margins (over a peak load expressed with a 50% POE) of 20-25% on a long term basis, within which ample scope existed for operational reserves. Probabilistic studies based on random outage events were tempered by the testing of the resulting reserve plant margins against a variety of multiple contingencies (i.e. which currently are ignored) to ensure that the overall result was socially and politically acceptable. The utilities did not rely only on the results of probabilistic studies or on one single criterion.

Since the start of the NEM, NEMMCo and the Reliability Panel have progressively reduced minimum reserve plant margins – from around 25% at market start (on a 50% POE peak load basis with no diversity between peak loads), to around 15% at the present time, after allowing for a 5% peak load diversity. NEMMCo relies on the results of Monte Carlo based probabilistic studies, assuming random independent outages of individual components and on the unserved energy measure of reliability. The results are not tested against a range of possible multiple dependent outages.

Actual reserve margins experienced in the NEM have been much higher than the minimums set by NEMMCo, both for the NEM as a whole and for the individual States. Actual NEM margins have been in the range 28% to 50% based on actual peak demands and after allowing for diversity. The Reliability Panel established the existing reliability standard in a period when reserve plant margins were very high. The acceptability of the standard by the public, media and politicians has yet to be seriously tested. Perhaps most importantly, unserved energy figures are highly non linear and increase rapidly as reserve margins fall.

Overseas countries/utilities generally use probabilistic methods for reliability analysis. Most use a Loss of Load Probability approach, but about one third employ and unserved energy (USE) criterion. Most countries and utilities do not rely upon a single reliability measure, but make an assessment based on several factors. The average reserve plant margin on overseas countries/utilities resulting from the application of these reserve criteria is 22% based on a 50% POE peak load forecast. Even countries which operate competitive markets establish target reserve plant margin of around 20%, with only the larger and well-interconnected systems falling below this level (18-19% being typical in the USA, for example).

In the view of NewGen Power, there is a clear need to define planning reserves for long term application, and operational reserves for short term application. This is due to the increased uncertainty that applies to plant performance, load forecasts and commissioning / decommissioning dates in future years. Finally, minimum reserve plant margins should be stated on the basis of a 50% POE ("normal weather conditions"), rather than on a 10% PEO basis as at present.

Question 13: Should the standard be determined on a NEM-wide basis or separately for each region?

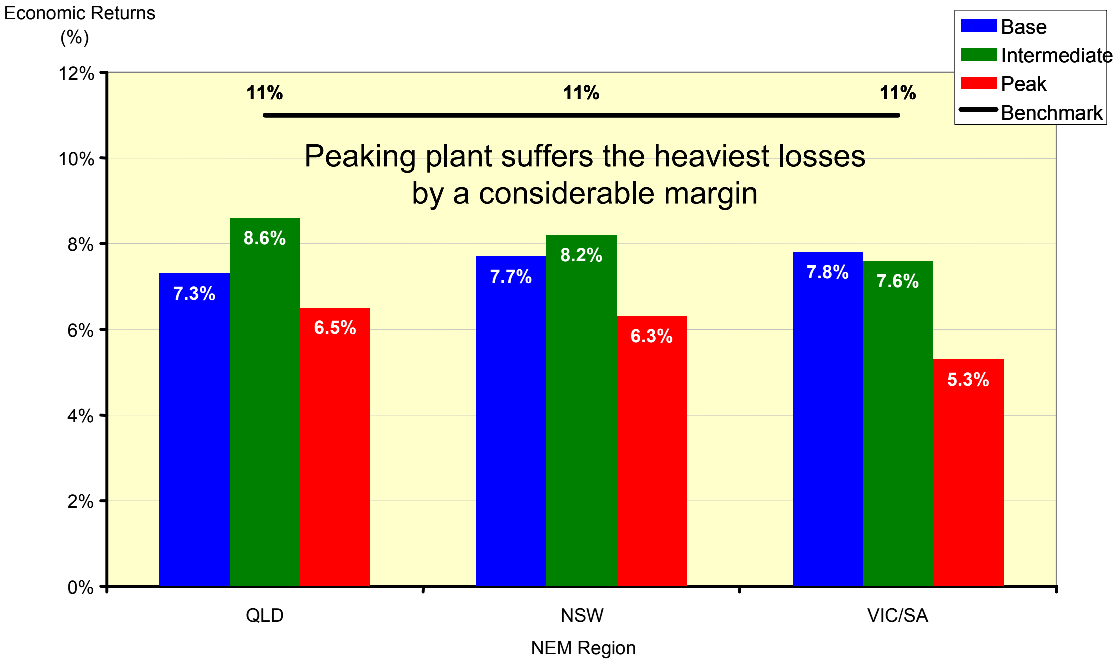
The NEM frequently operates on regional basis rather than as one whole market due to the inadequacy of transmission plant capacity. Accordingly, a degree of regional self-dependency is likely to be required until the transmission issue is resolved, that is, comprising strong and largely unconstrained interconnectors. Greater attention must therefore be paid to reserves in each region. Additionally, the issue of reliability must recognise some degree of political imperative. Indeed, as the custodians of policy, State Governments should sign off, in conjunction with the appropriate regulatory authority, on the level of reliability that they require for their jurisdiction. The rationale for this type of policy intervention is elegantly described in Bidwell and Henney (2004, p.11). They note that while electricity supply is an essential service, its financial insignificance to the bulk of electricity consumers means that they are not interested in responding to price signals per se, and in the event, liken reliability of electricity supply to a public good:

> *…it is necessary to have an external authority to act on the behalf of electricity consumers to determine an appropriate (joint) level of system-wide reliability and to ensure that there is an adequate level of system capacity. In this sense, power system reliability is somewhat like national defense. Each citizen cannot individually provide their own national defense. Nor can people have different levels of national defense. They must collectively decide what they want, and then appoint some authority to achieve it…*

Question 25: Do the current price mechanisms encourage appropriate investment? Explain why or why not.

For reasons set out in Question 2 above, NewGen Power would argue that current price mechanisms do not encourage appropriate investment, nor does it drive investment in a timely manner. Figure 1 below re-produces the generator financial returns as depicted in Table 5, that being the financial returns to generators under a competitive market, with VoLL at $10000 and a reliability constraint. Note that no plant earns a reasonable return, and peaking plant is especially penalised in the energy-only market environment.

Figure 2: Generator returns in the NEM in 2004/05 under perfectly optimal conditions including $10000 VoLL and a reliability constraint



Because peaking plant only produce when demand is exceptionally high, their merchant profitability is manifestly *random*. And high baseload plant availabilities compound the issue. Peluchon (2003, p.2) has noted that:

> *…Peak capacity investment, especially, seems quite problematic. An investment in base generation plant is a decision that requires forecasting base future prices. An investment in peak generation plant is a decision that requires much more information as peak prices depend on base prices as well as from the future investments in every other kind of generation capacity. The revenue generated by peak plant is therefore much more hazardous than base plant, since it produces only when every other plant produces at full capacity or cannot produce. In the same way an option is said to be 'out-of-the-money', peak plant has a value that may change drastically with any change in the way the supply-demand balance evolves...*

The extent to which a peaking plant can be *in-* or *out-of-the-money* is quantified in Table 6. Here, a 300MW Open Cycle Gas Turbine (OCGT) is simulated, and assumed to be dispatched at its *marginal cost of production* of $65.00/MWh, 'back-cast' against the historical spot price outcomes in Queensland – which according to the results in Table 5 and Figure 2 above, is likely to be the most profitable region for peaking plant. Table 6 includes operational data (run time, capacity factor, energy sent out, unit starts and gas demand) and financial data (revenue, variable costs, earnings, benchmark returns representing fixed costs and capital charges, and the annual profit and loss). Finally, and most importantly is the market data, with the most significant statistic being the fair-value (i.e. premium) of a $100.00/MWh-strike Cap derivative.

Table 6: Operating and financial data for a simulated 300MW OCGT in Queensland

SRMC ~ $65.00/MWh	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05
Operational Data							
Run Time (hrs)	933	844	767	293	285	156	144
Capacity Factor (%)	5%	5%	4%	2%	2%	1%	1%
Energy (MWh so)	279,750	253,200	229,950	87,750	85,350	46,650	43,050
Starts (#)	482	386	370	170	190	100	70
Gas demand (PJ)	3.2	2.9	2.6	1.0	1.0	0.5	0.5
Financial Data							
Merchant Revenue ($M)	87.2	54.1	33.2	26.5	37.8	19.9	13.8
Fuel, Starts & VOM ($M)	20.7	18.3	16.8	6.6	6.6	3.6	3.2
Earnings ($M)	66.6	35.8	16.4	19.8	31.2	16.3	10.7
Benchmark earnings ($M)	28.1	28.1	28.1	28.1	28.1	28.1	28.1
Profit/Loss	38.5	7.8	(11.6)	(8.2)	3.1	(11.8)	(17.4)
Market Data							
$100 Cap Value ($/MWh)	$ 26.37	$ 13.94	$ 6.15	$ 7.98	$ 12.70	$ 6.57	$ 4.23
Average Spot ($/MWh)	59.84	44.13	41.33	35.34	37.79	28.18	28.96
Average Peak ($/MWh)	76.73	59.50	58.70	45.09	51.50	37.17	37.80
Spot Standard Deviation	219.23	160.12	71.13	149.23	205.36	183.04	109.33
Volatility Index	3.66	3.63	1.72	4.22	5.44	6.50	3.78

Discounted cash flow modeling of a 300MW OCGT plant indicates that to break-even, the value of $100/MWh Caps needs to be approximately $10.70/MWh on a continuous basis, and the plant needs to be fully hedged at this price.[3] Note from Table 6 that whenever the value of the Cap falls below $10.70/MWh, the simulated plant incurs a loss. It is therefore not surprising that peaking plant proponents experience difficulties raising the requisite debt and equity finance in order to enter on an economic, and a timely basis, if at all. Neuhoff and De Vries (2004, p.3) pinpoint the most likely market outcome in deregulated energy-only markets in the absence of 'long-term' hedge contracts:

> *…[In the absence of long-term contracts] peaking plant is only remunerated in times of generation scarcity and hence face volatile returns. Investors therefore postpone their investment until the expected electricity price is higher, and require higher rates of return…*

Neuhoff and De Vries (2004) provide an insightful analysis as to the extent and impact of higher rates of return on ultimate plant cost and market prices in England & Wales. They explain that the uncertain revenue stream is anticipated by investors, and following anecdotal evidence, conclude that the weighted average cost of capital increases by around 7% for peaking plant investments in the absence of long-term contracts. At the efficient rate of investment with long-dated Cap contracts, the annual carrying cost of a peaking plant in the NEM is, as noted above, likely to be in the order of $10.70/MWh. But following the conclusions from Neuhoff and De Vries (2004), the carrying cost of purely merchant peaking plant would increase to $16.50/MWh.[4] This being the case, the

[3] This is obviously a problematic assumption because of the inherent price risk associated with a coincident unit outage and a $10,000/MWh (Value of Lost Load) price spike.
[4] These results were calculated using a discounted cash flow model of a peaking plant using discount rates of 11% and 18% respectively.

wholesale average electricity price would need to rise substantially (i.e. by $5.80/MWh per annum) prior to new investments in peaking plant occurring.

While spot prices are clearly unpredictable and volatile, hedges relating to peaking plant are too. For example, a commonly cited entry cost of new base plant is around $35.00/MWh, and historic annual baseload hedge prices have tended to oscillate around this number by +/- $5.00/MWh. Indeed, hedge prices in Queensland, New South Wales, Victoria and South Australia are all currently within the $30.00 to $40.00 range. Yet for peaking plant, which requires cap premiums of around $10-11/MWh, have witnessed premiums fall to as low as $4.00/MWh and rise to as high as $20.00/MWh (the latter obviously being in short bursts associated with supply shortages).

Question 26: If not, how should the mechanisms be modified to improve that effectiveness?

If the propositions included in Question 25 are accepted, then in consequence, long-dated hedge contracts or some other long-term market mechanism (e.g. capacity payments) are essential in order to minimize the cost of new entrant peaking plant, otherwise electricity prices will increase, and system reliability will necessarily deteriorate.[5]

In order to achieve maximum dynamic efficiency in the deployment of peaking plant, long term debt finance is required, and like any other capital intensive investment, with gearing ratio's of 60-70%. But in order for these fundamental financing conditions to hold for a peaking plant development in light of its otherwise 'hazardous' merchant revenue stream, it is essential that a long-dated hedge contract be signed with a retailer. Generally speaking, in order to secure 10-year money, the term of hedge contracts would need to be 7-10 years.

But securing long-term hedge contracts in the NEM is especially complex. The advent of Full Retail Contestability (FRC) in the energy-only NEM raises obvious problems for electricity retailers in terms of signing a large portfolio of 10-year hedge agreements. Neuhoff and De Vries (2004, p.18) noted that if a retailer has signed a portfolio of long-term hedge contracts, and market prices fall in any given year, fiscal problems can emerge:

> *…new retail companies may enter the market and offer cheap retail electricity. If the regulatory agencies succeed in achieving Full Retail Competition, then switching costs will be low for consumers and they will move towards these new retail companies. Under such circumstances, all retail companies would need to follow. Retail companies with [a large portfolio of out-of-the-money] long-term contracts would incur losses. Some would eventually go bankrupt and would not honor their contracts…*

Anderson, Hu and Winchester (2006) undertook extensive market research amongst NEM participants and confirmed a tension between retailers and generators in relation to the optimal term of hedge contracts. In the case of retailers, they found preferred terms

[5] One might argue that government-owned generators are able to develop peaking plants without hedge contracts and at lower cost due to their ability to finance such machines on-balance sheet, with debt obtained through State borrowing agencies, thus funding the project at the corporate cost of capital. However, this is merely crystallizing an implicit Government subsidy, with taxpayers bearing the market risk of the plant's ultimate performance. Taking this argument to its illogical extreme, Governments should fund *all* risky projects.

of just 1-3 years, as this was the longest time-horizon over which they have a degree of clarity on load profiles and over which the interaction between supply and demand could be reliably forecast, including the advent of new supply-side entrants. Additionally, a difficulty faced by retailers with significant contestable loads is that large customers may be won or lost at relatively short notice, again impacting their forecast load. Indeed, one retail trader was quoted in the Anderson et al. (2006, p.19) research as saying:

> *…Not too many people want to go out past three years because the water is getting a bit murky out there…*

Newbury (2002) considered the impact of limited long-dated hedge contracts under FRC and an energy-only market in England and Wales and concluded it to be sufficiently problematic as to necessitate institutional change amongst deregulated energy-only electricity markets. The change envisaged was one that would create a credible counterparty for generators to sign long-term contracts, viz. by reinstating regional monopolies to electricity retailers so that domestic consumers would not have the option to switch.

Since reversing FRC is most unlikely, there is therefore limited prospects for long term hedge contracts in the NEM. Thus, with long-term hedges being an unreliable source of contracts, it would seem that the only viable solution is to introduce a capacity market.

Question 28: Are the current price mechanisms appropriate tools for limiting the exposure of market participants to extreme price outcomes?

Vertical Integration (VI)[6] has become a dominant strategy for retailers in the NEM for limiting their exposure to market extremes. VI is a natural outworking of the NEM energy-only gross pool and provides a method of reducing the cost and uncertainty of contracting, and the origins of VI seem clear enough. During the late-1990s in the Victorian region, spot prices and contract prices had reached critically low levels. During the 1997/98 financial year for example, the (pre-NEM) Vic-NSW market result were just $14.50/MWh in the spot market and around $18.00-20.00/MWh in the hedge market. At this point in time, the Government, the Power Exchange, and all generator and retailer participants in the region were well aware of the requirement for new peaking plant by the summer of 2000/01. But the energy-only market was delivering such low spot and hedge contract prices in prior years that, unsurprisingly, no entity was willing to invest in the required capacity in a timely manner (i.e. timely in a *physical* as opposed to *financial* sense). This Victorian paradigm was so significant that it was labelled *The Top End Problem.* Predictably, inadequate generating plant capacity was soon followed by inadequate hedge capacity – a situation not previously contemplated by the then stand-alone electricity retailers. To compound the risk that retailers were facing, a case was put forward to the regulator to raise the Value of Lost Load (VoLL) from $5,000/MWh to $30,000/MWh on the basis that the infrequency of price spikes, and the cost of new peaking plant, would need rises of this magnitude in order to justify new investment.[7] In the end, the regulator accepted the argument that VoLL needed to be raised, albeit to $10,000/MWh. The change was implemented in April 2002.

[6] For the purposes of this research, VI refers to the situation whereby retailers build, acquire or secure the dispatch-rights of generating plant - primarily being gas-fired intermediate and peaking plant.
[7] Presumably such calculations were based on merchant revenues.

The combination of excess base plant in the Victorian region driving critically low underlying spot prices, an energy-only market environment with limited ability for any generator let alone peaking plant to recover its reasonable costs, the absence of new entrant peaking plant, a growing deficit in the availability of much needed hedge contracts, and finally, the announcement that VoLL would be lifted to $10,000/MWh all culminated in the space of three months during the 2000/01 summer. This sealed the fate of VI as a business strategy for retailers in that region. Like the domino effect, now that VI has become a dominant retail strategy in Victoria, all non-niche retailers in the NEM are now reassessing their positions with respect to the ownership of, or control over, generating plant as virtually a requisite condition of survival.

VI appears to be a logical and viable solution given the current market environment and current policy settings. And to be sure, there is no evidence that the strategy is, thus far at least, anything other than successful for the entities following this line. But its long-run success in the NEM hinges critically on two issues which seem to be diametrically opposed:

1. From a participant perspective, for the VI entities to ensure that transfer pricing of in-house generating plant remains 'in-the-money', it is *almost a necessary condition* for capacity to be short-supplied to ensure cost recovery due to the nature of the energy-only gross pool market.[8] Neuhoff and De Vries (2004, p.20) examined the long-run profitability of VI in some detail in their research:

    > *…One might argue that vertical integration by generators into the retail sector, which is common, has the side-effect of effectively creating long-term contracts between generation and retail companies. However, if the retail market is competitive, then integration of retailers and generators does not provide the required long term contracts to secure investment, because final consumers are not included in the long term contract. At times of low wholesale electricity prices, final customers could continue to switch supplies and vertically integrated retail companies will also lose their customers. Therefore vertically integrated retailers and generators cannot offer electricity tariffs according to long run marginal costs, but will vary the tariffs with the average wholesale price…*

2. From a policy perspective, the preferences of consumers and therefore the objectives of government, regulatory authorities and policy makers vis-à-vis reliability of supply need to be met. If the market fails this underlying, and indeed paramount objective, participants must reasonably expect policy intervention in some form or another.

This latter point is worth analyzing further. If it were the case that, for example, electricity retailers were 'prohibited' from owning or controlling generating plant, they would be obliged to purchase all of their hedge requirements from incumbent or new entrant portfolio generators. Portfolio generators, as a principle, do not fully hedge their

[8] The anti-thesis to this is that retailers use their 'controlled' peaking plant capacity to reduce the frequency and intensity of price spikes. Indeed, during several price spike events in Victoria during early 2006 , portfolio generators withdrew capacity to drive up the spot market while VI-controlled peaking plant were re-bid below marginal cost in order to moderate the spot market, as noted by Creative Energy Solutions (2006a, 2006b). When peaking plant is used to neutralise price spike events, underlying market volatility is reduced and in turn, so too is the premia and value associated with hedge contracts. In theory at least, this benefits the retailer but will adversely effect the profitability of portfolio generators. While a legitimate market strategy, the long-run impact of price-spike lopping could compound the damage of energy-only markets on reliability of supply – because the inadequate price signals that exist before the effects of VI are taken into account will be further *baffled* after the effects of VI are accounted for. In simple terms, neutralizing price spikes may artificially delay even further the optimal *financial* timing of entry, which as discussed previously, already lags the *physical* requirement for entry by a number of years.

capacity for reasons of self-insurance. Anderson et al. (2006) noted that just as retailers face extreme spot price risk when under-hedged, generators face extreme price risk when they are over-hedged relative to available capacity. Consequently, portfolio generators typically follow an *n-1 hedging strategy* – thus holding final units in reserve to cover such outages. In particular, Anderson et al. (2006, p.26) found:

> *…from the interviews we carried out, it seems that on average [portfolio] generators are about 70-80% contracted…*

If portfolio generators withhold some component of their capacity, then by implication, *some level* of system reserve is being inherently supplied. In contrast, the nature of the VI strategy is to match swing load with intermediate and peaking plant capacity to reduce or even avoid the cost of underwriting a portfolio generator's self-insuring strategy. That being the case, as VI entities shift their intermediate and peaking hedge capacity requirements from portfolio generators to in-house subsidiaries, the required generation insurance strategy is effectively internalized (with offsetting demand management) without the non-firm risk being discounted to the same extent - understandably. Thus, if the trend of VI continues, it is possible that the market will become even further short-supplied in peaking plant, and by implication, so too will prevailing reserve plant margins at the whole of system level – the VI effect.

If system reserves drop as a result of the VI effect, there is little doubt that the value of transfer prices within VI entities would be *deep-in-the-money*, and of course for Consumers, Government, Regulators and Policy Makers, the power system will most certainly experience widespread black-outs, save mild summer and winter conditions or extraordinarily high plant availabilities. But more importantly, as Bidwell and Henney (2004) have noted when a market reaches this juncture, portfolio generators exercise market power, and with insufficient installed capacity, prices boom. Following this is the risk of an *excess entry result*, a development boom where new entrants exceed system requirements by multiples. Predictably, what then follows is a bust and poor investor returns. Thus is the market cycle of Queensland (1998-2005) and Victoria (2000-2006).

Question 29: If no, what are the most appropriate alternative mechanisms? What are the relevant settings and why?;

Question 31: Would the introduction of improved forward market mechanism contribute to reliability outcomes?; and

Question 35: Are there operational or other changes that could be made to improve the effectiveness of the price mechanisms in terms of their impact on supply reliability outcomes?

NewGen Power has argued that the energy-only market is inherently unstable with no definable equilibrium. One might logically question why a meltdown has not yet occurred in the NEM, and what is the remedy?

A meltdown has not occurred because the power system has, as noted earlier, thrived on its 'monopoly plant stock' provided to it at inception in 1998, and has been aided by a *billion dollar chicken* competition in Queensland. High demand (PoE10) has also been avoided on working weekdays. The combination of these factors has until now shielded the demand-side from a number of otherwise inevitable perils.[9] But the last of the monopoly oversupply in the state of NSW is about to be exhausted in aggregate.

As for the remedy, it can be found in the academic literature of electricity supply industry economists from the late-1940s and late-1960s. The underlying problem described in this submission, that is, the lack of a stable equilibrium in an energy-only market with a reliability constraint, was solved by former *Electricite de France* Chief Economist, Marcel Boiteux in 1949. Boiteux's (1949) concept was that an efficient power system would involve determining a marginal price to be paid to all dispatched plant, based on the cost of the load-following unit in each period, and added to this was the marginal capacity cost (i.e. the carrying cost of a new peaking plant), which was paid during peak periods. His calculations determined that all plant would *just* recover all of their reasonable costs. Adding substantially to the Boiteux (1949) constructs was former Chief Economist of the Central Electricity Generating Board of England &Wales Tom Berrie's (1967a, 1967b, and 1967c) works, which defines the optimum mix of plant – and can be used to define the optimal portfolio of plant (and was used to derive the "optimal portfolio" in Tables 1 and 3).

Taking the Boiteux (1949) and Berrie (1967a-c) concepts and incorporating them in the Nemesys Model, a sustainable power system equilibrium can be derived. To illustrate this, the model results from Table 5 have been recast in the Nemesys Model with two primary changes, as follows:

1. A reduction in the level of VoLL from $10000/MWh to $2000/MWh; and

2. The addition of a 'capacity payment pool' or mandated 'capacity payments market' equal to the carrying cost of an OCGT, payable to the optimal level of plant capacity (as opposed to the actual level of plant capacity).

The 'capacity payment pool' is calculated for each region, and each region's pool is determined by multiplying the requisite availability-adjusted 'optimal level' of generating capacity (MW) by the aggregate fixed cost of carrying an OCGT (i.e. $10.70/MWh) over the entire 17520 half-hour periods in the year. The capacity payment pool is then paid to all generators at a unit rate ($/MWh), based on plant availability in each half-hour period. The modeled power system is otherwise identical, and the uniform, first-price mandatory gross pool auction mechanism that currently exists is assumed to continue with changes (1) and (2) above.

The results of this analysis are illustrated in Table 7 – which has the same five model-output columns as Table 5, with Electricity Load, Generating Plant and System Reliability outputs being identical. System unit cost and the aggregate costs in the Financial Results section are also identical. System prices and revenue differ very significantly, however. Because VoLL has been reduced from $10000/MWh to just $2000/MWh, average spot prices have reduced markedly. Taking the unconstrained NEM as an example in Table 7 below, the competitive spot price has reduced from $28.24/MWh (refer Table 5) to just $22.35/MWh. But the addition of the capacity payment pool, which is paid to available generators in each half-hour period, drives the average clearing price to $38.94/MWh, just 2¢ short of the system unit cost of $38.96/MWh. Under this market, retailers and generators would therefore hedge against two individual markets:

[9] The peaking plant crisis that occurred in Victoria during 2000/01 notwithstanding.

- The spot market, with expected flat swap prices of around $22.00 - $22.50/MWh in equilibrium (as opposed to the current $35.00 - $40.00/MWh); and

- The capacity market, with expected prices of around $10.70/MWh per MW available.

Table 7: Power system scenario results using 2004/05 load data under conditions of an optimal plant mix, perfect competition, capacity payments and VoLL of $2,000.00/MWh

Statistics with VoLL at:	$ 2,000.00	QLD	NSW	VIC/SA	ΣSTATES	NEM
Electricity Load						*unconstrained*
Peak demand	(MW)	8,232	12,884	10,986	29,403	29,403
Energy demand	(GWh)	49,440	74,432	62,414	186,287	186,662
Load factor	(%)	69%	66%	65%	72%	72%
Generating Plant						
Base plant	(MW)	6,600	9,900	7,920	24,420	24,420
Intermediate	(MW)	750	1,125	1,125	3,000	2,250
Peak plant	(MW)	2,720	4,160	3,840	10,720	7,200
Aggregate	(MW)	10,070	15,185	12,885	38,140	33,870
System Reliability						
Lost load	(%)	0.000%	0.002%	0.002%	0.001%	0.002%
System Reserve	(%)	22%	18%	17%	30%	15%
System Price/Cost						
Spot Price	($/MWh)	22.56	22.81	22.71	22.71	22.35
Capacity Price	($/MWh)	10.70	10.70	10.70	10.70	10.70
Spot + Capacity Price	($/MWh)	39.88	39.96	40.76	40.21	38.94
System unit cost	($/MWh)	41.37	41.37	41.35	41.36	38.96
Implied loss	($/MWh)	-1.49	-1.41	-0.59	-1.15	-0.02
Cost recovery	(%)	96%	97%	99%	97%	100%
Financial Results						
Asset Value (market)	($M)	12,727.5	19,151.3	15,941.3	47,820.0	44,392.5
Merchant revenue	($M)	1,115.5	1,684.2	1,447.0	4,246.8	4,391.9
Capacity Revenue	($M)	856.2	1,290.2	1,096.8	3,243.2	2,876.6
Total Revenue	($M)	1,971.7	2,974.4	2,543.8	7,490.0	7,268.5
Fuel costs	($M)	519.0	782.4	669.8	1,971.1	1,938.6
O&M costs	($M)	274.8	413.3	342.5	1,030.6	972.4
Capital costs	($M)	1,251.5	1,883.3	1,568.4	4,703.3	4,361.2
Implied loss	($M)	-73.5	-104.6	-36.9	-215.1	-3.7
Economic Returns (benchmark return = 11%)						
Base load SCpf plant	(%)	10.2%	10.3%	10.7%	10.4%	10.8%
Intermediate NGCC plant	(%)	11.5%	11.5%	11.2%	11.4%	11.6%
Peaking OCGT plant	(%)	12.5%	12.2%	11.6%	12.1%	12.1%
Aggregate plant stock	(%)	10.6%	10.6%	10.8%	10.7%	11.0%

Note that cost recovery is 100% or close thereto, and that the financial results balance (i.e. the $3.7million implied loss being a rounding error in the context of a $44.4 billion asset base). Similarly, the economic returns of plant are all roughly in line with benchmark, the difference in returns in this particular study being driven by the availability assumptions associated with gas-fired plant and coal plant and marginal deviations in the plant mix due to the indivisibility of plant capacity. These deviations notwithstanding, the results in each region are in line with the aggregate NEM outcome.

It is useful to observe how such a market might behave under varying conditions of over- and under-supply. For a 'capacity payment pool' to work effectively, it must send the appropriate signals under deteriorating and over-heated investment conditions. To illustrate the behaviour of the 'capacity and energy' gross pool market, Table 8 produces model results for New South Wales under various over- and undersupply scenarios, holding electricity load constant.

Table 8: New South Wales scenarios of optimal supply, oversupply and undersupply

Statistics with VoLL at:	$ 2,000.00	Optimal plant supply	Base plant oversupply	Peak plant oversupply	Base plant undersupply	Peak plant undersupply
Aggregate						
Base plant	(MW)	9,900	11,220	9,900	9,240	9,900
Intermediate	(MW)	1,125	1,125	1,125	1,125	1,125
Peak plant	(MW)	4,160	4,160	5,440	4,160	3,680
Aggregate	(MW)	15,185	16,505	16,465	14,525	14,705
System Reliability						
Lost load	(%)	0.002%	0.000%	0.000%	0.006%	0.005%
System Reserve	(%)	18%	28%	28%	13%	14%
System Price/Cost						
Spot Price	($/MWh)	22.81	13.61	20.37	30.29	25.71
Capacity Price	($/MWh)	10.70	9.85	9.85	11.18	11.06
Spot + Capacity Price	($/MWh)	39.96	30.97	38.17	47.31	42.24
System unit cost	($/MWh)	41.37	43.75	42.87	40.55	40.80
Implied loss	($/MWh)	-1.41	-12.78	-4.70	6.77	1.44
Cost recovery	(%)	97%	71%	89%	117%	104%
Financial Results						
Asset Value (market)	($M)	19,151.3	21,131.3	20,111.3	18,161.3	18,791.3
Merchant revenue	($M)	1,684.2	1,014.5	1,551.9	2,230.7	1,853.1
Capacity Revenue	($M)	1,290.2	1,290.4	1,289.2	1,290.9	1,290.9
Total Revenue	($M)	2,974.4	2,304.9	2,841.1	3,521.6	3,144.0
Fuel costs	($M)	782.4	728.2	782.5	834.3	782.2
O&M costs	($M)	413.3	451.1	429.3	397.3	407.3
Capital costs	($M)	1,883.3	2,077.2	1,979.5	1,786.4	1,847.3
Implied loss	($M)	-104.6	-951.6	-350.2	503.6	107.2
Economic Returns (benchmark return = 11%)						
Base load SCpf plant	(%)	10.3%	7.4%	9.6%	12.6%	10.9%
Intermediate NGCC plant	(%)	11.5%	8.6%	10.4%	13.2%	12.5%
Peaking OCGT plant	(%)	12.2%	10.0%	10.3%	14.0%	14.0%
Aggregate plant stock	(%)	10.6%	7.8%	9.8%	12.8%	11.4%

The first column of results is reproduced from Table 8 and represents the optimal plant mix solution. The second results column involves a scenario whereby base plant has been deliberately overbuilt by 2 x 660MW units, with the reserve plant margin increasing from 18% to 28%. Holding the value of the 'capacity payment pool' constant, capacity payments are reduced from $10.70/MWh to $9.85/MWh, with the resulting loss to generators being of the order of $12.78/MWh. The peaking plant oversupply scenario (3rd column results) has a similar impact on reserve margin and therefore, the capacity payment. However, the loss incurred is substantially smaller (at $4.70/MWh) because of healthier spot prices, as would be expected.

The final two columns deal with scenarios of undersupply. The first of these, where base plant is assumed to be undersupplied by 1 x 660MW unit, exhibits a sharp increase in system price. Note that in holding the capacity payment pool constant with a lower aggregate plant stock, the capacity price is lifted to $11.18/MWh. Consequently, generators as a class earn a net return of 12.8% against the 11% benchmark, and the ability to enter profitably is clear. In the undersupplied peaking scenario, the results are less exaggerated with aggregate returns reaching 11.4%. But at a capacity payment of $11.18/MWh, there is little doubt that peaking plant entry would occur.

In short, the presence of a capacity payment pool, divisible by the aggregate plant stock, enables a tractable, and definable equilibrium to be established without the need to exercise market power. And while a reliable market for reserve has been established, the extent of volatility has also been reduced substantially, as Table 9 notes, by a factor of more than 2½ times:

Table 9: Market price outcomes in oversupply and undersupply conditions

New South Wales region	Energy-only VoLL at $10,000	Capacity + VoLL at $2,000
Undersupplied (-660MW)	$55.60/MWh	$47.31/MWh
Oversupplied (+1320MW)	$15.10/MWh	$30.97/MWh
Volatility:	0.55	0.21

There is, however, a major ideological shift required by the industry, consumers and governments in order to progress from an energy-only market to a capacity and energy market. As Bidwell (2005, p.14) has noted, the concept of a capacity payment shifts a key variable from the market to a central authority:

> *…[Establishment of the capacity payment pool] requires an administratively determined vertical demand curve set at the point that will produce the desired reliability level…*

In simple terms, the level of reserve plant, which determines the capacity payment pool, needs to be set by some administrative body such as the Australian Energy Market Commission after consultation with the jurisdiction to which it applies. In the scenarios outlined in Table 7 for example, reserve plant margins for each jurisdiction were 'administratively determined' at a level whereby the current reliability constraint would not be violated, based on the plant technologies deployed and assumed plant availabilities.[10] This raises an issue as to whether such administration is necessary, or whether Adam Smith's 'invisible hand' is more appropriate. The contention in this submission is that markets fail, and it is the role of government to fix them. And in the

[10] If the actual plant stock that exists in each region was used in the model, the reserve planning margins would no-doubt vary due to the greater diversity of unit capacities and technologies.

case at hand, the market failure relates to the absence of a definable equilibrium, given a reliability constraint.

Concluding Remarks

An emphasis of this submission is the introduction of capacity payments as a mechanism to enhance the timeliness of resource adequacy in the NEM, which in turn, should ensure that reliability of supply meets the requisite benchmarks. The purpose of this submission is not to question the efficacy of the mandatory gross pool. The gross pool and the uniform first-price auction clearing mechanism remain sound theoretical constructs that help maximize static productive efficiency. What this submission has questioned is whether an energy-only market can result in a stable equilibrium and deliver satisfactory outcomes from a reliability of supply perspective - be it a gross pool, a net pool, a regional market, a nodal market, with- or without FRC and VI. And the results of the quantitative analysis were clear enough – competitive energy-only markets do not have a stable or definable equilibrium. The presence of heavy fixed costs and compressed marginal cost curves ensures this result.

Additionally, while this submission has advocated the introduction of capacity payments, it has touched seldom and lightly on how a capacity market and the payment for capacity is best organized – and this therefore remains an issue that would require further consideration by the AEMC. The manner in which a capacity payment is recovered from end-use consumers has not been addressed. In this submission, for simplicity, a flat $10.70/MWh payment was assumed for all available plant in each half-hour of the year when the plant stock was optimal. The unit price was assumed to increase or decrease according to the supply-demand balance relative to required reserves (i.e. the 'capacity payment pool' remains constant). But such a simplistic design would be open to manipulation by portfolio generators during periods of capacity scarcity. It is easy to imagine the withdrawal of plant capacity by large portfolio generators in order to drive price spikes in the spot market that lead to energy revenue gains that greatly exceed the short-run loss of capacity revenue. However, a rich body of research in this area does exist from which the AEMC could draw from to provide policy avenues to overcome such abuses.

It is useful to review the likely implications arising from the introduction of capacity payments in the NEM. Certainly, while the economic arguments for introducing a capacity payments pool are bordering on overwhelming, such a substantial institutional change needs to be introduced sufficiently far enough ahead (e.g. five years) so as to allow market participants, investors and financiers to adjust to the new regime appropriately, and to minimize the potential claim of 'regulatory risk' in the NEM.

- **State Governments** should find such an institutional change highly appealing. The ability to administratively determine the requisite reserve plant margin for their region/electorate provides Government with the 'lever' that they have missed following the dismantling of the respective State Electricity Commissions. Importantly, it provides them with a lever and eliminates the need to retain ownership in generation or retail as an *electricity supply business of last resort.* Similarly, it removes the temptation to invest early in what are otherwise defined as uneconomic projects and evidence of political intervention.

- **Electricity Retailers** would benefit from reducing their exposure to the extreme business cycles that characterise energy-only markets. As noted in Table 9 above, the level of market volatility will necessarily decline - if for no other reason than the reduction in the VoLL from $10,000 to $2,000. But more importantly, the incidence of a retailer free-riding off the actions of a *courageous retailer* who does sign long-dated contracts to facilitate peaking plant entry are almost eliminated.

- The benefits to the **Generators** are clear enough. The financial outcomes of the various portfolios of base, intermediate and peak varied at the margin. But these results reflected the model assumptions, specifically, base plant availabilities were assumed to be 2% lower than intermediate and peaking plant availabilities, and plant capacity was not perfectly divisible, and thus base plant in all cases were *'slightly'* overweight. Additionally, and perhaps appropriately, the returns accurately reflect the likely volatility of returns facing each class of generation. In reality, peaking plant (e.g. with take-or-pay fuel contracts) will continue to face higher risks due to uncertainties associated with weather and plant availabilities of the baseload fleet. Applied to the real world, as with any theoretical construct, there will be winners and losers of greater magnitudes due to variations in all the factors of production associated with power generation. For example, firms with special resource endowments (e.g. low cost fuel source), exceptional organizational efficiencies, or those who raised finance during low interest rate periods will fare better than the average. The reverse is also equally possible.

- **Equity Investors** would also benefit from a capacity and energy market. There exists a class of investors who have sought risky investments in the merchant power industry, no doubt with an expectation of earning returns higher than those on offer from the regulated electricity industry sector. But these higher risk-adjusted returns are likely to be 'illusory'. The reason for this is that first, as this submission has attempted to demonstrate, there is not a definable equilibrium in a competitive energy-only market with a reliability constraint. Second, this being the case, generators can only recover their costs when they exercise market power (i.e. bad VoLL) which then invariably becomes the subject of political intervention – as the generation sector discovered via the re-bidding inquiry during 2002. And third, if the wholesale market does clear at sufficient rates from load-shedding events (i.e. good VoLL), the system will be near the edge of collapse and State Governments will again intervene in any event.

- Economic theory has long been relaxed with the proposition that **Consumers** do not willingly reveal their true preferences. And to that end, it is difficult to conclude whether such an institutional change will suit all customers. However, for the overwhelming majority of domestic and commercial consumers, we may postulate that they would prefer a competitive market that delivers a stable price path when the commodity in question is effectively an essential service. Large industrials may have a preference for a boom-bust market, although the low level of demand-side management in the 31,000MW NEM provides some insight as to the extent of those customers truly interested in active market participation. Besides which, demand bidding would logically qualify for capacity payments, thus creating a revenue stream for astute consumers.

The historical analysis of the NEM power system presented in this submission, in particular, Tables 1 and 3, found that the dynamic efficiency of the NEM has, in aggregate, improved since market start with oversupply reducing from 2700MW to 400MW over a seven-year history. But dynamic efficiency from a structural perspective has deteriorated substantially, with peaking plant shifting from an underweight position of 1500MW to underweight 3900MW over the same timeframe.

The analysis of the economics of peaking plant demonstrated that their profitability is especially random, and therefore hazardous, in the energy-only NEM. To compound the prospects for new peaking plant, simulations of the NEM regions under conditions of a competitive market with an optimal plant mix and reliability constraint found them to be least profitable. The combination of these findings helps to explain the current lack of peaking plant within the aggregate plant mix. It also points to the fact that market failure, and in particular, inadequate reliability, is predictable.

Using a series of assumed plant cost and technology assumptions in Table 4, modeling of the NEM power system and its regions under conditions of a competitive market and a reliability constraint found that there is no definable equilibrium, and as a result, a competitive energy-only market is inherently unstable, as demonstrated in Table 5 and Figure 2. The power system would need to be near the edge of collapse before generators could recover their reasonable costs, thus violating the reliability constraint.

A key recommendation in this submission is to reduce VoLL to $2000 and to introduce a capacity payment pool, payable at the rate equivalent to the annual carrying cost of an OCGT. Modeling results in Table 7 confirmed that a stable equilibrium could be achieved, with the aggregate plant stock in all regions earning at or close to benchmark returns. Table 8 confirmed such a market would behave as expected, and reduced price volatility markedly (Table 9).

In the absence of this important institutional change, the energy-only market will, with a grinding inevitability, continue to experience a cycle of capacity shortage, the exercise of generator market power, a sharp rise in market prices and potentially unacceptable load shedding, consumer outrage and political intervention, a development frenzy 5-minutes after midnight, followed by a price recession until the next shortage. And like clockwork, it will predictably occur about six years later.

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