The Dynamic Efficiency Gains from Introducing Capacity Payments in the NEM Gross Pool

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Abstract

Australia's National Electricity Market (NEM) has been a beacon for Governments around the world considering power industry reform. However, while the energy-only NEM has served Australia well since 1998, deep structural supply-side faults exist. Competitive energy-only markets do not have a stable equilibrium solution unless reliability constraints are violated, market power is exercised, or scarcity pricing operates unabated. But the political economy of electricity means none of this is likely. This research finds that by reducing the NEM price cap and introducing a 'Capacity Payments Pool', a tractable and politically acceptable equilibrium can be established to facilitate timely plant entry.

1. Introduction

Over the ten years that the National Electricity Market (NEM) has been in operation, state-based monopoly power generators have been restructured and reformed, costs have fallen, prices reflect more competitive levels and plant oversupply, which had long plagued the industry, has cleared. Thus, one could rightly conclude that the 'template' reform objectives of enhancing productive (cost), allocative (price) and dynamic (expansion) efficiency have been achieved. But while there is little doubt that productive and allocative efficiency improvements in all regions of the NEM have been marked, and that the dynamic efficiency of the NEM has been adequate at the aggregate level, the NEM appears to have delivered sub-optimal dynamic outcomes when the structure of the supply-side is analysed. The NEM has, on balance, delivered sufficient generating plant capacity between 1998 and 2006, notwithstanding the dramatic events in Victoria during the summer of 2000-01 when capacity stocks were largely exhausted. But system reliability has had more to do with the high-quality oversupply of monopoly plant that the NEM inherited at inception, along with an *excess entry result* in Queensland, and in many cases fortuitously mild weather conditions, as opposed to a smooth and timely *invisible hand* that might loosely be associated with an 'energy-only' market. As Roques et al. (2005) noted there is simply insufficient experience with deregulated electricity markets to conclude that investment will be both timely and adequate. They also noted that the world's electricity markets are only just beginning to approach their first major 'investment cycle' as surplus capacity from the pre-reform era is finally absorbed.

While it is all well and good for 'free-marketeers' to suggest that consumers should somehow accept lesser reliability levels and higher prices periodically, it is politicians who are ultimately held accountable when the electricity supply industry underperforms vis-à-vis societal expectations (Besser et al. 2002; Oren, 2003; Roques, 2005). The average domestic consumer still considers electricity 'an essential service' rather than a tradable commodity. Considered in this light, an adequate reserve plant margin is an externality to electricity production and consumption in the energy-only NEM. 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

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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...

Thus is the objective of this research; to demonstrate, by use of a dynamic partial equilibrium simulation model of the East Australian power system, the quantitative effects of an ‘energy-only’ market and a ‘capacity and energy’ market model on power station investment and economic returns in a large thermal power system. This simulation approach is somewhat at odds with recent economic literature on investment, which tends to draw heavily from Finance Theory. This material emphasizes price, demand and output uncertainty, modeled as stochastic processes primarily by way of continuous-time Geometric Brownian Motion (GBM) Models – the seminal works for which can be found in Dixit and Pindyck (1994). However, such an approach does not fit neatly with this study or gross pool energy-only markets for three reasons. First, as Foster, Hinich and Wild (2008) have noted, it is unclear that a GBM model can adequately describe key characteristics including the evident periodicity in both half-hourly load and spot price time series data in the NEM. Second, in this article the focus is on the aggregate power system and not the actions of individual firms per se. Third, virtually all power system analyses are, for the reasons prior, undertaken by dynamic power system simulation modeling with a base case and sensitivity studies, and not by GBM Models, be that for policy analysis, real-world ‘bankable’ investment decisions, or industry budget forecasting (see for example Brennan and Melanie, 1998; Simshauser, 2006; MMA, 2006; CRA, 2008).

This article is structured as follows: Section 2 reviews the gains required from reform. Section 3 addresses the performance of the NEM between 1998 and 2005. Section 4 examines the economics of peaking plant. Section 5 examines the impact of Full Retail Contestability and Vertical Integration. Section 6 discusses the inherent instability of energy-only markets, while in Sections 7, 8 and 9, modeling results of a combined energy and capacity payment market are presented and analysed. Section 10 reviews the limitations of capacity markets, Section 11 canvasses the implications of introducing capacity payments on various sectoral interests, and conclusions follow in Section 12.

2. Gains Required from Microeconomic Reform of the Power Generation Industry

During the 1980s and 1990s, the status of the monopoly power generation industry in South-Eastern Australia was bordering on critical. By the mid-1980s, New South Wales had invested in so much base load capacity that it would take more than 20 years to clear. And by the early-1990s, Victoria had invested so excessively in base load plant that the State Credit Rating was down-graded, and a Labor Government was forced to privatise its newest power station as a result. Electricity tariffs were substantially above competitive levels and consequently, the requirement for, and objectives of, reform were clear.

It is useful to examine the dynamic efficiency of the aggregate East Australian generating plant portfolio in 1997-98, just prior to the commencement of the NEM.² Table 1 depicts the optimal mix of base, intermediate and peaking plant for the NEM in 1997-98 and contrasts this with the actual stock of plant that existed at the time.

² The NEM commenced in December 1998 and comprised the eastern and southern Australian states of Queensland, New South Wales, Victoria, South Australia and the Australian Capital Territory. Tasmania joined the NEM on 29 May 2005 and was interconnected with the mainland on 29 April 2006.

Table 1: NEM Generating Plant Portfolio Balance in 1997-98

NEM 1997-98	Optimal (MW)	Actual (MW)	Portfolio balance (MW)
Baseload	20,400	24,500	4,100 <i>overweight</i>
Intermediate	2,000	2,100	100 <i>overweight</i>
Peaking	8,200	6,700	-1,500 <i>underweight</i>
Total	30,600	33,300	2,700 <i>oversupplied</i>

Data Source (Actuals): esaa (2007).

The NEM generating portfolio was substantially *overweight* base plant, with around 4100 MW of excess supply – located mainly in the states of Victoria and New South Wales. Intermediate plant was roughly even, while peaking plant was *underweight* by 1500 MW, with the system being oversupplied in aggregate by around 2700 MW against a coincident peak load of about 25,000 MW. By taking the capital cost assumptions from Table 6 (below), the market value of these ‘structural faults’ can be quantified at \$5.1 billion or 13 per cent of the \$43.9 billion NEM power station fleet.³

3. The Performance of the NEM: 1998-2006

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.⁴ If this delay had not occurred, the entire structure of the Queensland system may now be quite different. Excess base load plant in Southern Australia during the late-1990s would have been able to export their surplus capacity northwards, as was originally envisaged. There was no doubt that Queensland urgently required new base load power, either by way of interconnection and hence access to surplus capacity from New South Wales, or through new investment within Queensland. But the spot prices that subsequently emerged in Queensland immediately after reform were so lucrative that the outcome was literally an *excess entry result* and a game of *billion dollar chicken* amongst multiple, low cost, coal-fired, potential new entrant generators.⁵ The history of NEM spot prices is provided in Table 2 - note in particular the very high spot price in Queensland during 1998-99.

Table 2: Average Spot Prices in the NEM

Price (\$/MWh)	1998-99	1999-00	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06
Queensland	59.84	44.11	41.33	35.34	37.79	28.19	28.96	28.12
New South Wales	24.32	28.28	37.69	34.76	43.91	32.37	39.33	37.24
Victoria	24.51	26.35	44.57	30.97	27.56	25.38	27.62	32.47

Data source: NEMMCo.

Perhaps not surprisingly, between 1998 and 2001 an additional 2100 MW of very low marginal running cost base load plant was committed and added to the plant stock in the Queensland region by 2003-04 against a requirement of 820 MW. Another important event that occurred in the NEM was high spot and contract prices in Victoria during 2000-01, a point in time where the existing plant stock in that region was largely exhausted. That prices in Victoria rose so sharply, from mid-\$20 spot prices in 1998-99 and 1999-00, to almost \$45.00/MWh in 2000-01, is typical of the result that occurs when a system is, on the one hand heavily *overweight* base plant, while on the other hand faces a looming capacity constraint in aggregate. When base plant capacity excessively dominates the aggregate supply function in an energy-only gross pool market, these

³ The \$5.1 billion result reflects the replacement cost. Table 7 lists the capital cost assumptions used in this calculation. Unless otherwise marked, all cost and price data is expressed in 2006 dollars.

⁴ The Queensland-New South Wales Interconnector (QNI) was re-routed from an eastern corridor (Eastlink) to the west (Westlink) due to public objection.

⁵ A full discussion of the *excess entry result* and *billion dollar chicken* in Queensland is provided in Simshauser (2001) and Simshauser (2006) respectively.

low-cost machines cannibalise the important ‘price-setting’ role of higher marginal cost intermediate and peaking plant. Consequently, base plant capacity sets price too-low, too-often which in turn can suppress a timely signal for new entry. As de Vries (2003) and Roques et al. (2005) have noted, in theory an energy-only market should provide an optimal level of plant capacity, but this optimum can be ‘easily disturbed’ by an array of market or political conditions. In other words, while a *physical system analysis* can clearly point to a near-term supply shortage, the economics of the energy-only market under competitive conditions and constrained scarcity pricing ‘fails’ in that the signaling for new plant occurs very suddenly, and with short term signals rather than long term ‘bankable’ signals (Besser et al. 2003). New peaking plant capacity was ultimately commissioned in Victoria, although it is generally accepted that from a security of supply perspective, it arrived ‘5-minutes after midnight’.

With the benefit of perfect hindsight (which clearly discounts the ‘uncertainty’ variable), over the period between 1997-98 and 2006-07 the NEM *physically required* the addition of 5800 MW of peaking plant and 300 MW of intermediate plant capacity. Had the QNI been commissioned in line with the eastern corridor proposal, no new base plant would have been required over this timeframe. In the absence of this, 820 MW of base plant was required in Queensland. However, as Table 3 clarifies, actual investments in new plant have deviated substantially from the cost-minimising solution given the sunk plant stock. The complete stock of new entrant plant in the NEM, including capacity (MW) and the replacement value (\$M) is illustrated in Table 3.⁶

Table 3: New Entrant Plant in the NEM and the Requirement for New Plant

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	900		
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	852		
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		240	
Braemar OCGT	2006	QLD	Private			450
Laverton North	2006	VIC	Public			300
TOTAL (MW)	5,546			2,345	1,094	2,107
Required (MW)	6,100			0	300	5,800
Surplus/Deficit (MW)	-554			2,273	794	-3,693
INVESTMENT (\$M)	6,246			3,518	1,149	1,580

*SCpf: Supercritical pulverised fuel. NGCC: Natural Gas Combined Cycle. OCGT: Open Cycle Gas Turbine

Source: esaa (2007)

⁶ During 2007 (just prior to publication), additional commitments of plant in the NEM included the 380MW Tallawarra intermediate plant and 600MW Uranquinty Peaking Plant in New South Wales, and the 600MW Darling Downs Base Plant in Queensland.

Based on the difference in system demand between 1997-98 and 2006-07, the required increase in plant to service aggregate demand amounted to 6100 MW. 5546 MW was delivered, and of this, 672 MW via government-backed Power Purchase Agreements and 1295 MW through a *billion dollar chicken* competition in Queensland, an incidence which is unlikely to be repeated.⁷ Table 4 provides the portfolio balance for the NEM as at the end of the 2006-07 financial year.⁸

Table 4: NEM Generating Plant Portfolio Balance in 2006-07

NEM 2006-07	Optimal (MW)	Actual (MW)	Portfolio balance (MW)
Baseload	24,300	26,900	2,600 <i>overweight</i>
Intermediate	2,400	3,200	800 <i>overweight</i>
Peaking	12,500	8,800	-3,700 <i>underweight</i>
Total	39,200	38,900	-300 <i>undersupplied</i>

Data source (Actuals): esaa (2007).

Despite these variations, from a dynamic efficiency perspective the 2006-07 outcome represents a substantial improvement on the 1997-98 result in that the system balance has reduced from a 2700 MW oversupply to a 300 MW deficit, which to be sure, in the context of a 40,000MW system 300MW should be considered as immaterial. The investment value of supply-side ‘structural faults’ has reduced from \$5.1 billion (13 per cent of aggregate investment) to just \$1.9 billion (4 per cent of investment). Strictly speaking, this represents a dynamic efficiency gain of \$348 million per annum via lower annual capital charges. But despite this, there is a worrying trend emerging from Table 4. Peaking plant as a class is now under-represented by 3700 MW as opposed to the 1997-98 result of 1500 MW as illustrated in Table 1.⁹

4. Market Failure: the Inadequate Entry of Peaking Plant

An area that has received relatively little attention in NEM circles is the relative dynamic performance of peaking plant entry in the NEM, a issue directly associated with the “generation resource adequacy” problem (Besser et al. 2002; Oren, 2003; Wen et al. 2004; Bushnell, 2005; Roques et al. 2005). As Peluchon (2003) noted in the case of Europe, and Roques et al. (2005) noted in the case of England and Wales (in both cases where similar problems are emerging), this is because newly deregulated energy-only markets have largely thrived on generation 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. The NEM market manager has a primary responsibility for system security, and a range of tools at its disposal to drive security including a ‘reserve trader’ option, which results in retailers paying particularly high prices.¹⁰ However, they are short-term focused measures in nature and by definition – since construction lags for power plant are at least 2-3 years, whereas reserve trading occurs just months prior to the forecast event.

Peaking plant has shifted from *1500 MW underweight* in 1997-98 to *3700 MW underweight* in 2006-07. In a climate of rising peak loads, this should be deeply concerning to Consumers, Retailers, State Governments, Energy Regulators and Policy Makers alike. So why has a peaking plant deficit emerged? And more importantly, is the situation likely to deteriorate? The

⁷ The harsh experience of Project Banks in the NEM between 1998 and 2003 should ensure this is the case.

⁸ Reserve margins used to calculate this aggregated result are 15 per cent for New South Wales, 17 per cent for Victoria and South Australia, and 20 per cent for Queensland.

⁹ A hindsight analysis needs to be interpreted carefully. However, since this analysis is focusing on the peak capacity problem, and that peak load growth is consistently outpacing energy growth, any hindsight analysis of peaking plant capacity shortfalls will invariably be understated.

¹⁰ Note that the NEM Rules contain security measures aimed at assisting the market to meet its ‘reliability criteria. These measures, in which the market operator calls for bids, have been successful in procuring marginal shortfalls of up to 200MW through additional short term supply or demand responses over summer months.

inadequacy of peaking plant entry, and its poor entry outlook, can be traced back to key economic characteristics associated with outcomes in the energy-only market. Because peaking plant only produce when demand is exceptionally high, their merchant profitability is manifestly *random*. 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 5. Here, a 300 MW 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. Table 5 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 (that is, premium) of a \$100.00/MWh-strike Cap derivative.

Table 5: Operating and Financial Data for a Simulated 300 MW OCGT in Queensland

SRMC ~ \$65.00/MWh	1998-99	1999-00	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06
Operational Data								
Run Time (hrs)	933	844	767	293	285	156	144	127
Capacity Factor (%)	5%	5%	4%	2%	2%	1%	1%	1%
Energy (MWh so)	279,750	253,200	229,950	87,750	85,350	46,650	43,050	37,950
Starts (#)	482	386	370	170	190	100	70	72
Gas demand (PJ)	3.2	2.9	2.6	1.0	1.0	0.5	0.5	0.4
Financial Data								
Merchant Revenue (\$M)	87.2	54.1	33.2	26.5	37.8	19.9	13.8	18.6
Fuel, Starts & VOM (\$M)	20.7	18.3	16.8	6.6	6.6	3.6	3.2	2.9
Earnings (\$M)	66.6	35.8	16.4	19.8	31.2	16.3	10.7	15.7
Benchmark earnings (\$M)	28.1	28.1	28.1	28.1	28.1	28.1	28.1	22.8
Profit/Loss	38.5	7.8	(11.6)	(8.2)	3.1	(11.8)	(17.4)	(7.1)
Market Data								
\$100 Cap Value (\$/MWh)	\$ 26.37	\$ 13.94	\$ 6.15	\$ 7.98	\$ 12.70	\$ 6.57	\$ 4.23	\$ 10.37
Average Spot (\$/MWh)	59.84	44.13	41.33	35.34	37.79	28.18	28.96	31.77
Average Peak (\$/MWh)	76.73	59.50	58.70	45.09	51.50	37.17	37.80	49.64
Spot Standard Deviation	219.23	160.12	71.13	149.23	205.36	183.04	109.33	227.81
Volatility Index	3.66	3.63	1.72	4.22	5.44	6.50	3.78	7.17

Data source (half-hourly spot prices): NEMMCo.

Discounted cash flow modeling of a 300 MW OCGT plant (using cost data from Table 7) indicates that to break-even, the value of \$100/MWh Caps needs to be approximately \$10.70/MWh on a continuous basis. Note from Table 5 that whenever the value of the Cap falls below \$10.70/MWh, the simulated plant incurs an economic loss. It is therefore not entirely surprising that peaking plant proponents may experience difficulties raising the requisite debt and equity finance in order to enter on an economic and a timely basis (Oren, 2003; de Vries, 2003). Short to medium term hedge contract can provide a buffer to assist plant economics. However, forward Cap contracts can and do trade at heavy discounts to break-even prices. Neuhooff 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:

...[Without 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...

5. The Requirement for Courageous Retailers with 'FRC' in Energy-Only Markets

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 65 per cent plus. 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 10 years. But 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. Roques et al. (2005) have noted this to be a problem in England & Wales, where raising funds appears to have become a material obstacle to building new plant, with "*bankers extremely reluctant to engage in merchant power projects*". 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 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. A small number of *courageous retailers* in the NEM have signed long-dated hedge contracts in order to facilitate the timely entry of cost-efficient peaking plant. However, courageous retailers bear a heavy burden. All other competing retailers operating in the region, particularly smaller players who focus on hit-and-run tactics are able to free-ride off the actions of the courageous retailer. At a minimum, the cost of marginal system reserve is ultimately being carried by the courageous retailer. But under such circumstances, the Neuhoﬀ and De Vries (2004) scenario may begin to materialize, and if so, the retailer would commence a slow downward spiral through loss of market share, margin squeeze, and potentially, financial distress.

Vertical Integration (VI) of generation and retail, which is an emerging trend in the NEM, might be cited as a mechanism for overcoming the peaking plant constraint issue. But from a participant perspective, for 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, as we will see in later sections of this research.¹¹

¹¹ 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

A key policy issue that remains therefore is that of ‘generation resource adequacy’. While there is no doubt that load uncertainty drives courageous retailers and VI players to cover their positions by contracting for new plant, it is difficult to imagine such entities taking the full responsibility for ensuring that adequate plant capacity existed at the whole of region level, when their focus must surely be on adequacy for hedging their own load on an economic basis, and not that of the State. Similarly, there is no guarantee that retailers will hedge prudently, and in the event, may go out of business. Oren (2003) has noted that this is not just a theoretical possibility – it has indeed been experienced in California in 2001 and Texas in 2003. The NEM similarly experienced its first financially distressed retailer during 2007.

6. The Instability of Energy-Only Electricity Markets

Besser et al. (2002), Bidwell and Henney (2004), Booth (2005) and Simshauser (2001, 2006) have noted that energy-only markets are inherently unstable, and therefore the exercise of market power by generators is, to some extent, justified on the grounds that bidding at short run marginal cost cannot possibly lead to the recovery of reasonable costs (while VoLL caps exist). Bidwell and Henney (2004) examined the net pool arrangements in England and Wales and through the use of a static *idealized* perfectly competitive market model of a power system with no plant outages, demonstrated that the economic characteristics of thermal generation plant ensures that over time, aggregate income will be less than total cost. They concluded that not only is an energy-only market inherently unstable, but it does not have a sustainable or ‘defined equilibrium’.

A key objective of this research is to demonstrate that the energy-only NEM fails to reach a tractable equilibrium¹² under competitive conditions given a VoLL cap and a reliability constraint. However, before introducing the static and dynamic partial equilibrium models used to quantify this instability, it is first necessary to make certain assumptions about the values of existing plant and new entrant plant. For the purposes of this research, the cost of all existing and new entrant plant in the NEM is assumed to reflect the form of three generation technologies:

- Super Critical pulverized fuel (SCpf) plant, which perform baseload 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 6. Note that the short run marginal cost of production is calculated by multiplying the heat rate (kJ/kWh) 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 6: New Entrant Generating Plant Cost Assumptions

Generation technology	Capital cost (\$/kW)	Unit size (MW)	Variable O&M (\$/MWh)	Fixed O&M (\$M pa)	Useful life (Yrs)	Heat rate (kJ/kWh)	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%							

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 (2006). Clearly, as VI entities increase their generation capacity, this incentive evaporates – as witnessed by the same VI participant just two years later.

¹² In a dynamic and uncertain market setting, a stable equilibrium is in many respects illusory in any event. But a tractable equilibrium under controlled modeling conditions invariably means that market participants can calibrate trade and investment decisions against a theoretical long run marginal cost.

The average cost for a SCpf plant at a capacity factor of 90 per cent 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. The cost data contained in Table 6 and 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 requirement for system reserves, the competitive spot price, and aggregate system cost (Appendix I provides an overview of the Nemesys Model).¹³ 2005-06 data was deliberately selected to calibrate the model, in large part due to the relative stability of the operating electricity market in that year. Note that in contrast, the 2006-07 year was very adversely affected by extreme drought conditions, which remarkably, even had an impact on base load coal plant (via constrained cooling water supplies). The key outcomes from the simulation model have been reproduced in Table 7.

Table 7: Power System Scenario Results from Nemesys using 2005-06 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 <i>unconstrained</i>						
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 7. 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*

¹³ Note that in Nemesys, the variable *W_i* enables generators to economically withhold generating capacity in order to raise price. As a competitive market has been assumed in this analysis, the variable has been set to zero.

transmission system – that is, it is a scenario that describes what the power system *should* look like were it not for transmission congestion that exists in the NEM. The most important result from Table 7 is that despite the perfectly optimal and cost minimizing plant stock assumed, a stable equilibrium could not be reached in any region under competitive conditions and a VoLL cap of \$10,000. The model outputs in Table 7 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 per cent, with the aggregate NEM result highest at 72 per cent, which is driven by the diversity of loads across Eastern Australia. Next in Table 7 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 criteria for the NEM is *no more than 1GWh lost for every 50,000 served*, which implies a Loss of Load Probability benchmark of 0.002 per cent. 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 \$10000/MWh (market-ceiling) price spike events.

The next segment of Table 7, System Price/Cost, provides an important quantitative analysis of the energy-only NEM under competitive market conditions. The results demonstrate that there is not a sustainable equilibrium in any region. Note in every case that the competitive spot price is markedly lower than system cost. Cost recovery ratio’s range between 57 per cent – 72 per cent, with the result driven largely by system load factors. Cost recovery ratios rely critically on VoLL at \$10000/MWh. If, for example, VoLL was reduced to \$5000/MWh, the cost recovery ratio in the unconstrained NEM would reduce from 72 per cent to 63 per cent. If VoLL was raised from \$10000 to \$24500/MWh, cost recovery would occur given a minimum level of blackouts – but the political consequences of the price effects would likely be unacceptable as noted in Besser et al. (2002), Oren (2003), Wen et al. (2004), Bidwell and Henney (2004), Bushnell (2005), Roques et al. (2005) and others.

The Financial Results segment of Table 7 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 – and range between -\$14.05/MWh in the case of Queensland, and -\$17.66/MWh in the case of the combined Victoria-South Australia region.¹⁴ The Economic Returns by generator class and by region provided in Table 7 confirm that against the benchmark result of 11per cent, no technology makes an adequate return, and most importantly, peaking plant incurs the greatest losses. This fundamentally explains the ever deteriorating deficit in peaking plant. The results in Table 7 confirm that there is no evidence that the NEM, or any of its regions, have a tractable equilibrium given a reliability constraint and VoLL at \$10000. 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 per cent threshold by 2½ times, which naturally occurs when system reserves are driven down from 18per cent to 13per cent, or as noted above, when VoLL is increased to \$24500.

¹⁴ The Merchant Revenue calculations in Table 7 were calculated by reference to energy and spot price. That is, there is no hedge contract income included in the determination of revenues. One may argue that the absence of hedge revenues constitutes an inherent flaw in the analysis. However, such a criticism is too convenient. The power system analysis undertaken in Table 7 assumes a competitive market and the existence of the least-cost, optimal mix of plant. that is even allowing these principles to be violated at the extreme, and assuming the existence of a \$5.00/MWh spot-swap spread in a manner envisaged by Anderson et al. (2006), such margins pale into insignificance by comparison to the \$14.00 - \$17.00 losses incurred by generators in Table 7.

On the other hand, as one reviewer noted, power generators in the NEM do not operate in a purely competitive manner and often do bid above marginal cost. The example cited was the 2005-06 results for New South Wales. However, as noted in Simshauser (2005), this was also the region of the NEM that had a peaking plant capacity deficit in 2005-06 (demonstrating the purpose of this paper) and the region which had the highest concentration ratios, and is thus not entirely surprising. The implication is that plant levels need to be inadequate and market structure must remain highly concentrated and therefore inefficient in order for pricing to be remunerative. In the event, cost-recovery outcomes are purely reliant on (a) generators possessing at least transient, if not sustained, market power in order to achieve such results, and (b) regulators and politicians accepting that market power must be exercised – the degree to which is entirely uncertain and in the literature at least, is considered most unlikely (see Besser et al, 2003; Oren, 2003). Roques et al. (2005) note that the most convincing argument against energy-only markets lies in the difficulties for regulatory authorities to distinguish between market power abuse and legitimate scarcity rents. As evidence of this, it is interesting to note that the NEM's regulator, as a matter of policy, investigates every incident where spot price exceeds \$5000, but does not under any circumstances investigate when prices continuously fall below known generator cash costs – thus reinforcing the underlying problem raised in this and other articles on the political economy of energy-only electricity markets.

7. Incorporating Capacity Payments in the NEM Gross Pool

Since the energy-only gross pool with a VoLL cap is inherently unstable, why has a meltdown 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. High demand (that is, 10 per cent Probability of Exceedence or 'PoE10' demand scenarios) have occurred, but fortunately have rarely hit regions on working weekdays. The combination of these factors has until now shielded the demand-side from a number of otherwise inevitable perils. But the monopoly oversupply has now been largely exhausted in aggregate. As for the remedy, it can be found in the academic literature of electricity supply industry economists in Europe and England & Wales from the late-1940s and late-1960s respectively.

The underlying problem described in this paper was solved by former *Electricite de France* Chief Economist, Marcel Boiteux in 1949. Boiteux's (1949) seminal work solved the peak load pricing problem; power generation involves two factors of production, capacity and energy, and an efficient power system would ensure the marginal price is paid to all dispatched plant based on the cost of the load-following unit in each period, (that is, energy) with all available plant paid the marginal capacity cost or the carrying cost of a new peaking plant (that is, capacity). His calculations determined that all plant would *just* recover all of their reasonable costs. Adding to the Boiteux (1949) constructs was former Chief Economist of the *Central Electricity Generating Board* of England & Wales Tom Berrie's (1967) seminal works, which is illustrated in Figure 1, using live data for the combined Victoria-South Australian region of the NEM.

Figure 1: Static Partial Equilibrium Power System Model: Marginal Running Cost Curves and Load Duration Curve (Vic-SA) including Reserve Plant Margin

Berrie's (1967) static partial equilibrium model outlined in Figure 1 establishes the optimal plant mix for a given power system by transposing plant costs in light of production duties to create *annual running cost curves*. Annual running cost curves take into account power station costs on a capacity utilisation basis, thus capturing the rich blend of fixed and variable costs associated with the different generation technologies deployed in a thermal power system, the optimum combination of which will minimize the overall cost of supply. This partial equilibrium framework illustrated in Figure 1 uses the cost data from Table 6 (top graph) and a load duration curve for the Victoria-South Australian region (bottom graph).

In the top graph, the y-axis intercept marks the annual fixed cost of plant, while the slope of the cost curve signifies the variable running cost of the plant. Note from the top graph in Figure 1 that the lowest cost generation plant option for production duties up to 18 per cent capacity factor is the OCGT. Production duties above 45 per cent capacity factor are best served by SCpf plant. Intermediate production, which lies between these bounds, is best served by NGCC plant.¹⁵ When the intercept points of 18 per cent and 45 per cent are transposed down to the bottom graph in Figure 1 (that is, the power system load duration curve), the optimal mix of plant can be defined. When initially transposed, there is an implicit assumption that plant is operating at 100 per cent availability. Consequently, in order to minimise system cost, these equilibrium points need to be adjusted for expected outage rates. Thus, in Figure 1, the optimal mix of base plant at an assumed 100 per cent availability factor is around 7300 MW. After adjustments for outages, this result increases to 8100 MW. Similarly intermediate plant is adjusted from 750 MW to 800 MW. With peaking plant, the reserve margin is added, and any increases in base and intermediate plant are deducted. Accordingly, with perfect plant availability the requirement for peaking plant is 4800 MW and after adjustments is reduced to 4000 MW. The combination of Boiteux (1949) and Berrie (1967) thus ensures that productive (cost), allocative (price) and dynamic (expansion) efficiencies are maximised.

8. Dynamic Partial Equilibrium Model Results

Taking the Boiteux (1949) and Berrie (1967) concepts and incorporating them in the Nemesys Model, a more sustainable result can be derived. The two primary differences that have been effected in the Nemesys Model are as follows:

- i. A reduction in the level of VoLL from \$10000/MWh to \$2000/MWh; and
- ii. The addition of a 'capacity payment pool' 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 therefore calculated for each region, and each region's pool is determined by multiplying the requisite 'optimal level' of generating capacity (MW) by the aggregate fixed cost of carrying an OCGT (that is, \$10.70/MWh) over the entire 17520 half-hour periods in the year.¹⁶ The capacity payment pool is then paid to all generators at a unit rate (\$/MWh), albeit discounted for 'plant outages' in any given half-hour period as per Besser et al. (2003). The 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 8 – which has the same five model-output columns as Table 7, 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.¹⁷ Because VoLL has been reduced from \$10000/MWh to just \$2000/MWh, average spot prices have reduced markedly. This would be a key reform because, as de Vries (2003) has noted, scarcity pricing in energy-only markets with a high VoLL are exposed to extreme price manipulation. Taking the unconstrained NEM as an example in Table 8 below, the competitive spot price has reduced from \$28.24/MWh (Table 7) to just \$22.35/MWh. But the addition of the capacity

¹⁵ In terms of sensitivities, +/-10 per cent movement in the capital cost of OCGT plant leads to a +/-4 per cent movement in the optimal running duty. Similarly, +/- 10 per cent movement in the unit fuel cost for an OCGT plant leads to a +/-3 per cent movement in the optimal running duty. Thus, if both costs moved upwards, the optimal production duty for an OCGT plant would deteriorate from 18 per cent to just 11 per cent.

¹⁶ If the \$10.70 payment for each hour (i.e. 8760 hours) was to be paid in peak periods only, the result would need to be grossed-up for the reduced time, that is, \$25.00 per MW per peak hour (i.e. 3750 hours).

¹⁷ Note that the 'Lost Load' results in Table 8 differ marginally from those in Table 7. The number of events is virtually identical, but the severity of the outages differs. Due to the NEMESYS Monte Carlo simulation process, it is almost impossible to deliver two identical scenarios.

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:

- 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 8: Power System Scenario Results using 2005-06 Load Data under Conditions of an Optimal Plant Mix, Perfect Competition, Capacity Payments and VoLL of \$2000.00/MWh

Statistics with VoLL at:	\$ 2,000.00	QLD	NSW	VIC/SA	ESTATES	NEM
Electricity Load						<i>unconstrained</i>
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 per cent or close thereto, and that the financial results balance (that is, 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. And as one reviewer has noted, the higher returns attributed to peaking plant is perhaps appropriate, given that their operation (and therefore use of fuel) remains manifestly random. These deviations notwithstanding, the results in each region are in line with the aggregate NEM outcome.

9. Dynamic Behaviour of a Gross Pool Market with Capacity Payments

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 9 produces model results for New South Wales region of the NEM under various over- and undersupply scenarios, holding electricity load constant.

Table 9: 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 660 MW units, with the reserve plant margin increasing from 18 per cent to 28 per cent. 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 660 MW 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 per cent against the 11 per cent 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 per cent. But at a capacity payment of \$11.06/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 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 in the NEM has also been reduced substantially, as Table 10 notes, by a factor of more than 2½ times.

Table 10: Market Price Outcomes in Oversupply and Undersupply Conditions

New South Wales region	Energy-only VoLL at \$10000	Capacity + VoLL at \$2000
Undersupplied (-660 MW)	\$55.60/MWh	\$47.31/MWh
Oversupplied (+1320 MW)	\$15.10/MWh	\$30.97/MWh
Volatility (Coeff. of variation):	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) has noted, the concept of a capacity payment shifts a key variable from the market to a central authority. 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. In the scenarios outlined in Table 7, reserve plant margins were ‘administratively determined’ at a level whereby the reliability constraint would not be violated, based on the plant technologies deployed in Table 6. 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 research is that markets fail in the face of large externalities, and it is the role of government to fix them. And in the case at hand, the market failure relates to the absence of a definable equilibrium, given a reliability constraint and VoLL capped at \$10000 and scarcity pricing being politically untenable.

Thus we return to the problem identified at the outset; by introducing a capacity market, State Governments can decide, in conjunction with the appropriate regulatory authority, upon 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 domestic 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...

10. Experience with Capacity Markets

While this research has advocated the introduction of capacity payments, it is important to note that the historical experience with capacity markets has not been an outstanding success, as noted by Wen et al. (2004). Barker et al. (2004) who conducted a wide ranging review of capacity markets noted at that time there did not exist a functioning capacity market in the world that the Australian NEM could reliably draw from. Similarly, Bushnell (2005) noted that the reliability standards of capacity markets have been the subject of considerable controversy, and that

capacity markets invariably suppress spot prices and therefore reduce the value available for demand-side responses as an alternative to generating capacity (that is, since the ceiling price is lowered – although this overlooks the ability for the demand side to participate in capacity markets). Moran (2007) has noted that capacity markets inherited through the passage of time (that is, those pre-dating reforms) remained poorly functioning after reforms, while those created more recently have merely exchanged a poorly functioning energy market for a poorly functioning energy and capacity market, with the aggregate outcome for resource adequacy no different as a result. Roques et al. (2005) noted that capacity mechanisms are criticized for being based on engineering calculations (i.e. price and quantity) and can become disconnected with the underlying energy market. Moran (2007) has also noted that capacity markets tend to override the firm's commercial decision framework, and that in the New England market, capacity prices have mainly been close to zero. These are indeed valid criticisms given the nature of those designs.

While capacity markets are designed to make up what Bushnell (2005) refers to as 'missing money', they are said to fail to consider alternate options such as raising the price cap, or substantially increasing ancillary service revenues such as spinning reserves. Barker et al. (2004), who specifically considered the NEM in light of experience in the United States, concurred with such a view and indicated that Australia's focus should not be to implement a capacity market, but to shift the focus towards lifting scarcity pricing (nominating a shift from \$10000 to \$25000 – which is consistent with the \$24500 finding in this study for scarcity pricing), or dealing with peaking capacity compensation through other interventions such as emergency Power Purchase Agreements with dispatch at \$10000 VoLL pricing.

Bushnell (2005) noted that the requirements for resource adequacy in electricity “*are the most extensive and complicated seen in any industry*”. And in Australia at least, there has indeed been an asymmetric attitude by policy makers towards pricing, that is, low prices are ignored while scarcity pricing events have in all circumstances led to an industry ‘witch hunt’. As noted earlier, it is policy of the Australian Energy Regulator to *investigate every spot price event that exceeds half the threshold price cap*, an outcome well predicted in the economic literature on energy-only power systems (Oren, 2003; Besser et al. 2003; Wen et al. 2004). Thus, heightening VoLL to a level that would generate a sustainable equilibrium (for example \$24500), while theoretically possible, would seem to be politically unacceptable in the context of the NEM. In this paper, a ‘capacity payments pool’ has been suggested as opposed to ‘capacity markets’ that exist in the United States, in order to avoid failure in both the energy and capacity market to be remunerative.¹⁸ The newly formed Western Australian market is based on a similar ‘pooled’ principle, and while barely 12 months old, is reportedly working well. It requires load serving entities to procure a certain amount of capacity credits for the two-year period ahead in a manner consistent with that envisaged by Oren (2003). However the obvious criticism of such models, as noted by Wen et al. (2004) and Roques et al. (2005), is the potential for inadequate restructuring in the form of overinvestment.¹⁹

This research has touched seldom and lightly on how a capacity payment pool and the payment for capacity is best organized. For example, Moran (2007) noted that a capacity market can only conceivably be useful if it provides an investment signal some years out rather than in near time periods – a view which is clearly well founded given long lead construction times and the overwhelming capital requirement for new plant. Similarly, the manner in which capacity

¹⁸ One potential downside of a capacity payments pool is the potential for generators to exercise market power and raise spot prices above competitive levels, thus clearing windfall gains through the combination of the spot market and the capacity payments pool – as occurred in the original England and Wales market (Green, 1996a, 1996b; Green and Newbery 1992; Wolak and Patrick, 1997).

¹⁹ This view was expressed to the author by a senior officer of the IMOWA: Independent Market Operator in Western Australia in September 2007.

payments are recovered from end-use consumers has not been addressed. In this paper, 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 (that is, the ‘capacity payment pool’ remains constant). While this modelled approach demonstrated remunerative pricing, 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 energy market that lead to revenue gains that greatly exceed the short-run loss of capacity revenue. However, a rich body of research and applied concepts exist that provide policy avenues to overcome such abuses (see for example, Besser, 2003; Bidwell, 2005; Roques et al., 2005 and especially the WA Market Rules at www.imowa.com.au).

11. Sectoral Implications

It is useful to review the likely implications arising from the introduction of capacity payments in the NEM. While the theoretical economic basis for introducing a capacity payments pool is clear enough given generation resource adequacy is fundamentally an externality, such a substantial institutional change needs to be introduced sufficiently far enough ahead (for example five years minimum) 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 a ‘lever’ they have long 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 power generation or power 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.

Electricity retailers would benefit from reducing their exposure to the extreme business cycles that characterize energy-only, mandatory gross pool markets. As noted in Section 9, the level of market volatility will necessarily decline - if for no other reason than the reduction in the VoLL from \$10000 to \$2000 as noted in Besser et al. (2003). But more importantly, the requirement for, and implications of, being a *courageous retailer* soften considerably. In simple terms, the incidence of free-riding off the actions of a *courageous retailer* are almost eliminated.

The benefits to the generation sector are clear. Equity investors would 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 (poles and wires) electricity industry sector. But these higher risk-adjusted returns have historically been largely ‘illusory’. The reason for this is that first, as this research has already established, there is not a stable equilibrium in a competitive energy-only market with a VoLL cap and a reliability constraint. Second, this being the case, generators can only recover their costs when they exercise market power (that is, bad VoLL) which then invariably becomes the subject of political intervention – as the generation sector discovered via the Australian Competition and Consumer Commission re-bidding inquiry during 2002. And third, if the wholesale market does clear at sufficient rates from load-shedding events (that is, 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 customers 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. As a domestic consumer, this is most certainly the author's preference. Roques et al. (2005) noted that the most compelling argument in favour of a well-designed capacity mechanism is that it reduces consumer's exposures to price volatility, while providing steadier revenues to generators. Large industrials may have a preference for a boom-bust market, although the low level of demand-side management in the 40000 MW NEM (no more than 800MW in total) provides some insight as to the extent of customers truly interested in active market participation.

12. Summary

The purpose of this research was not to question the efficacy of the mandatory gross pool market model. The gross pool and the uniform first-price auction clearing mechanism remain sound theoretical constructs that help maximize static productive efficiency. What this research has questioned is whether an energy-only market can result in a stable equilibrium. And the results of the quantitative analysis were clear enough – competitive energy-only markets with a reliability constraint, a VoLL cap, and political aversion to scarcity pricing do not have a stable equilibrium. The presence of heavy fixed costs and compressed marginal cost curves ensures this result. The historical analysis of the NEM power system presented in this paper found that the dynamic efficiency of the NEM has, in aggregate, improved since market start with oversupply reducing from 2700 MW to 300 MW undersupply. But dynamic efficiency from a structural perspective has deteriorated substantially, with peaking plant shifting from an underweight position of 1500 MW to underweight 3700 MW over the same timeframe.

The key contribution to the economic literature on capacity markets emerging from this article is the simulation modelling results, specifically in relation to the economic returns made by the various classes of generators in an energy-only market with a VoLL cap and a reliability constraint. As against a benchmark 11 per cent, the modelling results indicated that no technology was capable of making an adequate return, and most importantly, peaking plant incurred the greatest losses given a VoLL cap. Additionally, the 'backcast financial analysis' of the economics of peaking plant demonstrated that their profitability is especially random, and therefore hazardous, in the energy-only NEM market. The combination of these findings helps to explain the ever deteriorating deficit of peaking plant within the aggregate NEM generating plant portfolio mix. It also points to the fact that market failure is predictable.

Modelling the market with a reduced VoLL of \$2000 and a capacity payment pool, payable at the rate equivalent to the annual carrying cost of an OCGT, confirmed that a stable equilibrium could be achieved without risk of political intervention, with the aggregate plant stock in all regions earning at, or close to, benchmark returns. 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, consumer outrage and political intervention, a development frenzy 5-minutes after midnight, followed by a price recession until the next shortage occurs. And like clockwork, it will predictably occur five-to-seven years later.

13. References

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APPENDIX 1 - Overview of the NEMESYS Model

The central aspect of NEMESYS, apart from the Monte Carlo joint-probabilistic simulation of power plant availability, is the economic dispatch model which determines the equilibria for a half-hour j as follows:

Let N be the number of dispatch periods (half hours) in the year, where $N = 17520$.

Let d_{ij} be the dispatch of unit i for period j (MW).

Let c_i be the maximum capacity of unit (MW).

Let m_i be the min load of unit i (MW) where $m_i \in [0, c_i]$

Let w_i be the available capacity economically withdrawn to a very high price band.

Let f_i be the fuel cost of unit i including any environmental impost (\$/MWh).

Let $b_i(l)$ be the price of the highest bid band that is dispatched when unit i is running at level l where

$$b_i(l) = 0 \text{ for } l \in [0, m_i]$$

$$b_i(l) = f_i \text{ for } l \in [m_i, c_i - w_i]$$

and

$$b_i(l) = \text{VOLL} \text{ for } l \in [c_i - w_i, c_i]$$

Let $r_i \in [0, 1]$ be the availability rate of unit i .

Let $a_{ij} \in \{0, 1\}$ be a random variate representing the availability of unit i for period j

such that $P(a_{ij} = 1) = r_i$.

The following constraints are placed on the unit dispatch $[d_{ij}]$.

Units can not dispatch beyond their maximum capacities.

Let $D_1 = \{[d_{ij}] \mid \forall i, j \bullet d_{ij} \in [0, c_i]\}$

Units do not dispatch during outages.

Let $D_2 = \{[d_{ij}] \in D_1 \mid \forall i, j \bullet d_{ij} = d_{ij} a_{ij}\}$

Units are dispatched to minimize lost load for each dispatch interval. The function of the dispatch model is to compute $q_{ij} \in D_4$.

Let $D_3 = \left\{ [d_{ij}] \in D_2 \mid \forall [q_{xy}] \in D_2 \bullet \forall n \bullet \left| p_n - \sum_i q_{in} \right| \geq \left| p_n - \sum_i d_{in} \right| \right\}$

Units are dispatched to minimize the marginal offer price for each dispatch interval.

Let $D_4 = \{[d_{ij}] \in D_3 \mid \forall [q_{xy}] \in D_3 \bullet \forall n \bullet \max_u (b_u(q_{un})) \geq \max_u (b_u(d_{un}))\}$

Spot price determination for period j is as follow

If $p_j > \sum_i q_{ij}$

$s_j = \text{VOLL}$

If $p_j \leq \sum_i q_{ij}$

$s_j = \max_i (b_i(q_{ij}))$

Output

A comprehensive set of data is produced for subsequent analysis. This includes, for each half-hourly period:

- Regional spot price,
- Loss of load MW, and
- For each power station, plant availability levels, energy production level, spot revenue, hedge contract receipts/payments, quantity of fuel consumed, and tonnes of CO₂ emitted