CRR REPORT APPENDIX

Prepared For:

AEMC: Reliability Panel

Modelling Methodology,

Input Assumptions and Results

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A.1 INTRODUCTION

This Appendix presents the methodology, input assumptions, data and results of modelling the four design options for market arrangements to manage reliability in the NEM that are considered in the main report.

The four design options are:

- **Status Quo (Option A)**: The current design, termed the status quo, with variations in the level of VoLL;
- **Option B**: Addition of a new ancillary service, termed the **Reliability Ancillary Service** (RAS);
- **Option C**: Contracting for standby capacity, or **standing reserve,** in various locations across the NEM; and
- **Option D**: A revised market design using the financial **Reliability Options** concept, which involves NEMMCO entering into cap contracts with effectively all capacity, and as a result paying an option fee to all generators.

Modelled results can be no better than the assumptions and data that support them. The model described here takes into account the technical and commercial characteristics of the NEM. It does not incorporate the possible impacts of introducing significant new features to the market, such as emission trading arrangements, or of material investments made for reasons other than in response to electricity market prices. We also assume that spot and contract arrangements work sufficiently to enable market participants to manage volatility of market outcomes.

These limitations are potentially significant and need to be considered when interpreting the modelled results. Consequently, the modelling presented here is only part of the overall picture. The results do, however, provide valuable insights into the performance of the different options, such as how certainty of revenue varies for similar revenue streams.

Our assessment of alternative designs and settings assumed that the level of VoLL remained at the current level <u>in real terms</u>, and the changes in the design introduce additional revenue or the same revenue with less variability.

In order to provide a basis for comparison, the alternatives were analysed assuming that the additional revenue was equivalent to the additional revenue for reserve plant from raising VoLL to $12,500/MWh in the status quo. Where appropriate, investment profitability was used as an indicator of commercial viability and used as the benchmark to which modelling of each alternative was managed. For example, where a new source of revenue was added to the market, it was assumed that investors would invest until the same level of profitability was achieved as in the status quo. In this way, the modelling was able to assess the *relative* impact of different designs. In practice, reduced variability of revenue would also imply that investors would apply lower discount rates, and for this reason variability of revenue has been reported for each case but no change in profitability ratio has been assumed. Changes in revenue streams can also be thought of as compensating for other more qualitative impediments that were identified in the report.

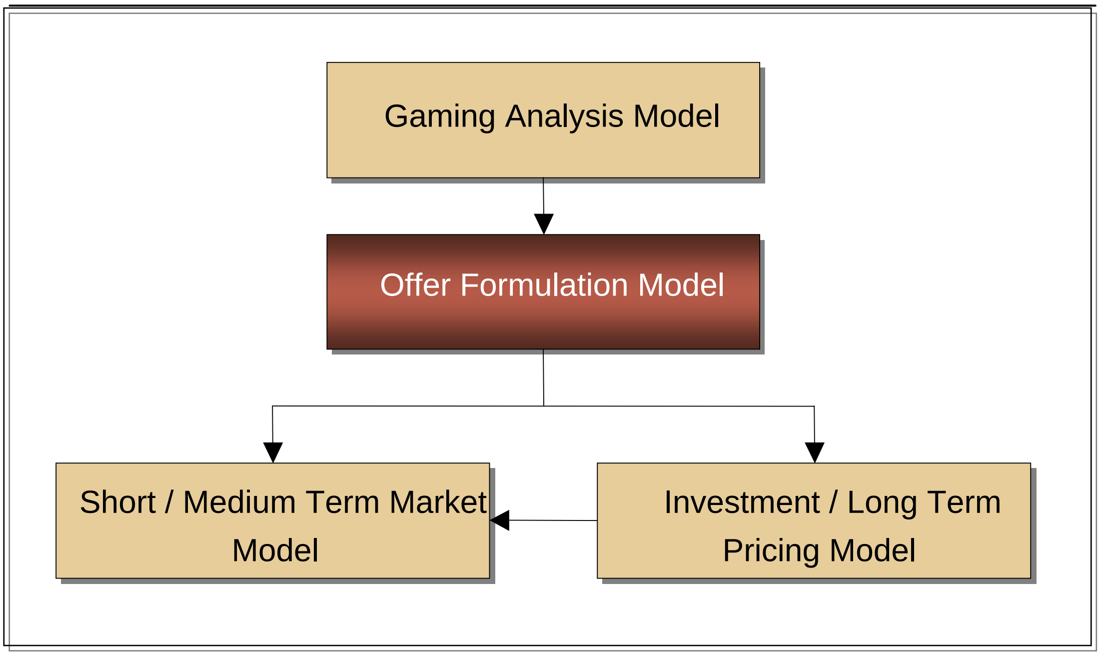
A.2 Modelling Approach

Analysis was undertaken using CRA's CEMOS modelling suite. CEMOS is a comprehensive suite of tools to analyse:

- Long term market expansion;
- Short term simulation; and
- Strategic generator bidding.

Figure 1 highlights the broad CEMOS functionalities, each of which is described in further detail below.

Figure 1: Overview of CEMOS Functionality



A.2.1 Long Term Investment Commitment and Outage Simulation

PEPPY is the component of the CEMOS suite that handles long-term investment simulation. PEPPY optimises electricity market investment and operational decisions over several years, taking into account the physical realities of the electrical power system. PEPPY provides a framework for developing insights about the implications of key market drivers over the longer term, including demand growth, load shape, type and amount of future generation entry, and the longer term effects of market power on system reliability. PEPPY models the supply and demand sides together, and the fixed and variable costs associated with both resources.

Key features include:

- Consideration of fuel costs, load growth and its temporal/spatial distribution, and new entrant capex;
- A Monte Carlo "engine" to simulate the random outages of generators around an *optimised* capacity plan;
- Transmission among interconnected regions; and
- Ancillary services (represented as a single spinning reserve requirement).

PEPPY uses annual load duration curves for each of the NEM regions. Within each load "block", PEPPY resembles the market clearing process in the NEM. By using load duration curves, PEPPY achieves relatively rapid solution times with relatively little loss of detail relevant to long-term investment decisions.

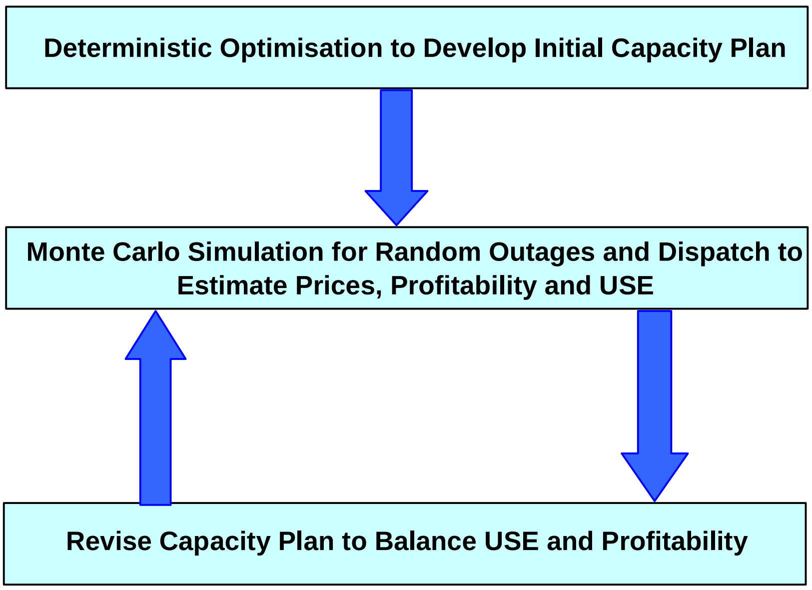
PEPPY is used to determine the market expansion using the following process as shown in Figure 2:

- A *deterministic* optimisation is used to decide the optimal location, timing and technology of generic new entrants such as total volume of coal, combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) plants using a de-rated capacity for planned and forced outages and a starting transmission plan, e.g. the projects identified in the Annual National Transmission Study (ANTS) as discussed later;
- The Monte Carlo engine is used to simulate random outage of generators and dispatch of existing and optimised new entrant generators for 100 randomly selected outage plans. The dispatch, Un-Served Energy (USE), profitability, etc. are calculated using the *average* outcome across these samples. These averages represent the expected outcome over a range of potential futures. Of particular importance are the expected USE statistics for each region and year that are compared against the NEM standard; and

- The generation and transmission capacity that the deterministic optimisation used / predicted may fall short of the NEM reliability standard because such optimisation of new generation capacity and utilisation of assumed transmission lines does not accurately reflect the impact of random breakdown of generators and may typically underestimate the USE. The deterministic optimisation of peaking investment may also predict new entry that does not necessarily meet a profitability target that may be reasonably be expected by a commercial investor – for instance, if a region has a very low load factor, peaking investments will be needed that achieve limited utilisation and hence revenue – given the VoLL cap on prices. In this way, the need for larger numbers of iterations is avoided, and a balance is obtained between profitability, generation expansion, network enhancement and reliability with sufficient accuracy for policy analysis.

Assessment of the status quo considered the sensitivity of USE to changes in VoLL.

Figure 2: Capacity Plan Methodology



A.2.2 Generator Bidding Simulation

The CONE module analyses strategic bidding opportunities electricity markets characterised by a relatively few competing firms or companies. Key features of the gaming module include:

- Strategic interaction among competing suppliers;
- Oligopolistic market behaviour;
- Cournot Nash equilibrium solution used as the basis of interaction;

- Bidding strategy that can be built around the Cournot solution;
- Recognition of short and long term demand elasticity;
- Recognition of peak/off-peak temporal load behaviour; and
- Alternative bases for generator offers.

The transmission constrained version of CONE (T-CONE) has been used to develop generator bids in the NEM for a range of demand growth, load shape, capacity entry and interconnection scenarios. CONE models the strategic interactions among generating companies for a range of demand conditions (e.g. peak and off-peak demand across different seasons) taking into account their short run marginal costs, availability, energy limits and contract positions.

Each company is assumed to maximise its own profit by adjusting its generation while considering the generation from all other companies and the level of demand response in the market. This is known as a Cournot game, the solution to which is defined as the generation levels at which each company has no incentive to adjust its supply further – because doing so would reduce its profit.

A.2.3 Half-Hourly Dispatch Simulation to Validate the Long Term Model Results

STEMM is a short term (daily/weekly) unit commitment model. The key features of STEMM include:

- Detailed consideration of generating unit start-up/shutdown, and ramping for energy/ancillary services
- Replication, where possible, of the market clearing process of the system;
- Chronological load profile;
- Transmission; and
- Ancillary services.

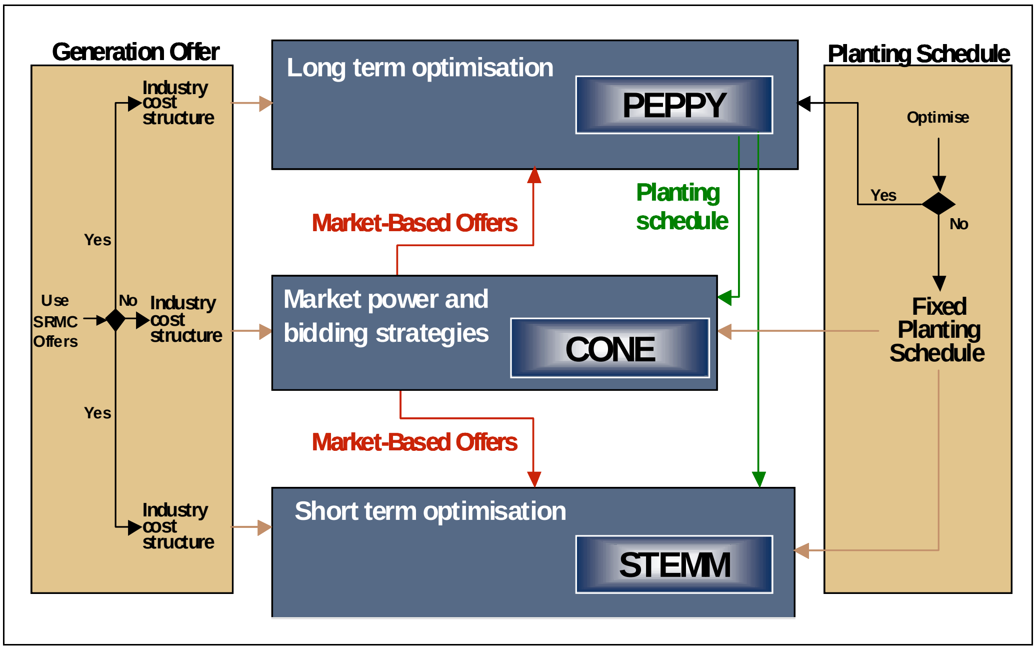
We have used STEMM primarily to validate the outcomes of the long term model. It provides a framework to develop insights about the short term (half-hourly) issues including the effect of the engineering characteristics of the gas/oil based existing/new units, shape of daily load curve and short term gaming behaviour/bidding strategies.

A.2.4 Interaction Among the CEMOS Modules

For the CRR, we linked the operation of some of the modules within the CEMOS suite, especially PEPPY and CONE. Figure 3 shows the linkages.

Both PEPPY and STEMM use the offers created by CONE. These offers are then used as the “cost” for dispatch of the generators. Both STEMM and CONE use the capacity plan created by PEPPY. This allows for the optimal new entry determined by PEPPY to be used in these other models.

Figure 3: Interaction Among CEMOS Modules



A.3 Key Input Assumptions

A.3.1 Modelling Timeframe

Any long term analysis including expansion of the market requires a sufficient “look ahead” period to develop a view on the long term supply-demand equilibrium. One issue that arises in this context is the “end effect” (or limited horizon effect) that may distort the investment decisions towards the end of the planning period because the model has inadequate information on the future profitability for the investments that are made close to the horizon. In order to minimise such distortions, we have run the analysis over the period from 2007 to 2020 and have used the results for the 10-year period over 2008-2017. In this way, the distortions for the period of interest are minimised.

A.3.2 Demand

The long term analysis in CEMOS uses annual load duration curves developed using the peak and energy projections shown in Table 1. We have used the medium economic growth scenario to project regional energy requirements from the NEM Statement of Opportunity 2006 (SOO 2006). SOO 2006 presents projections up to 2016, beyond which we have extrapolated the growth between 2015 and 2016 for the remaining four years of our analysis.

Since reliability issues and investment in peaking generation are intricately linked with the shape of the load duration curves, especially at high loads, we have analysed the 10% POE demand together with 50% POE demand. The half-hourly historic load shapes[1] that are used to generate the annual load duration curves are shown in Figure 4 to Figure 8.

Table 1: Regional Energy and Peak Demand Projections

Year	Region	Annual Energy (GWh)	Peak Demand (10% POE)	Peak Demand (50% POE)
2007	QLD	51785	10138	9597
2008		53771	10585	10014
2009		55667	10975	10377
2010		57418	11347	10720
2011		59266	11724	11070
2012		61249	12107	11424
2013		63042	12503	11791
2014		64927	12914	12171
2015		66816	13325	12551
2016		68893	13718	13022
2007	NSW	75600	15120	14150
2008		76840	15500	14520
2009		78160	15970	14940
2010		79380	16460	15370
2011		80960	16930	15780
2012		82290	17370	16190
2013		83790	17810	16570
2014		85190	18240	16960
2015		86680	18700	17350
2016		87857	19139	17779
2007	VIC	47336	10473	9627
2008		47591	10683	9805

1 Typical historic load shapes recommended in SOO are used to develop the load shapes.

Year	Region	Annual Energy (GWh)	Peak Demand (10% POE)	Peak Demand (50% POE)
2009		46975	10819	9914
2010		46971	10990	10057
2011		47097	11163	10203
2012		47983	11415	10428
2013		48530	11627	10613
2014		49286	11837	10802
2015		50223	12076	11020
2016		49619	12225	11227
2007	SA	12070	3506	3272
2008		11990	3609	3359
2009		12095	3680	3424
2010		12283	3730	3467
2011		12487	3778	3510
2012		12678	3824	3551
2013		12854	3866	3587
2014		13075	3916	3631
2015		13296	3984	3694
2016		13206	4051	3808
2007	TAS	10463	1844	1824
2008		10594	1869	1850
2009		10841	1909	1889
2010		10981	1936	1915
2011		11135	1965	1944
2012		11291	1996	1974
2013		11430	2023	2001
2014		11705	2066	2044
2015		11880	2094	2072
2016		11980	2117	2094

Data Source: SOO 2006

Figure 4: Normalised Load Shape for New South Wales

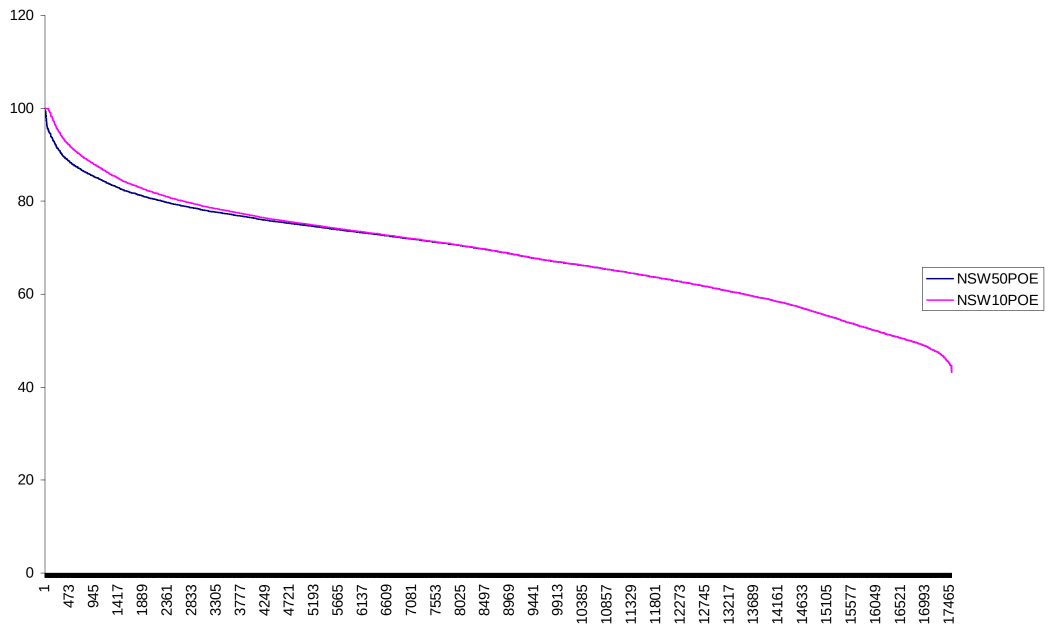


Figure 5: Normalised Load Shape for Victoria

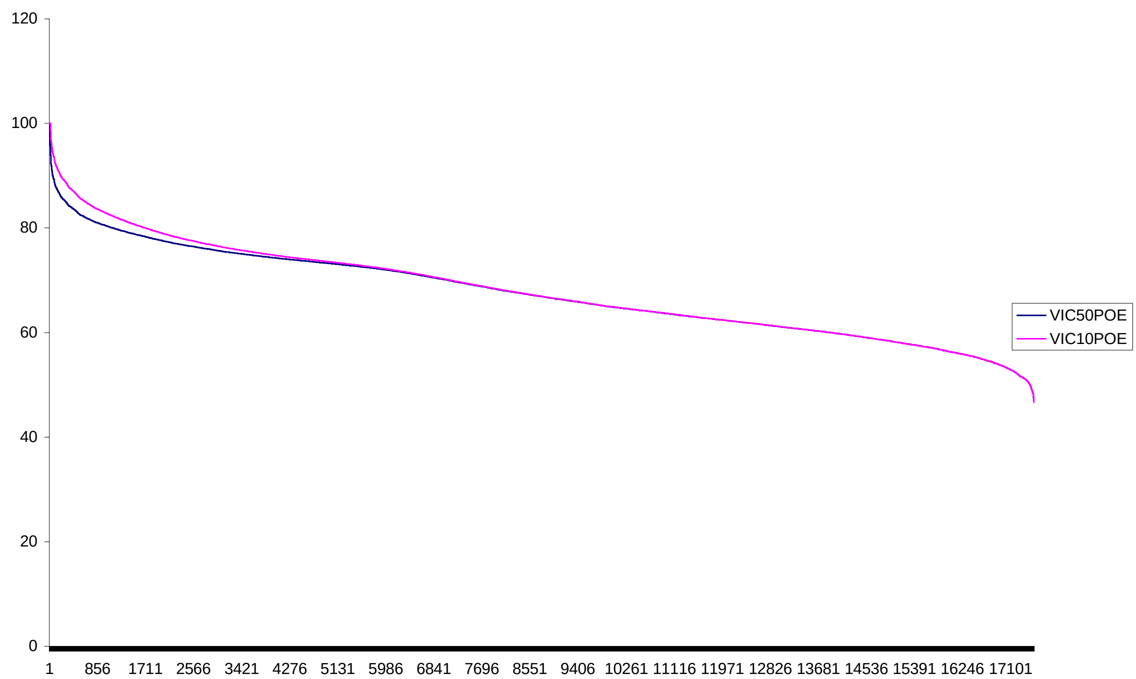


Figure 6: Normalised Load Shape for Queensland

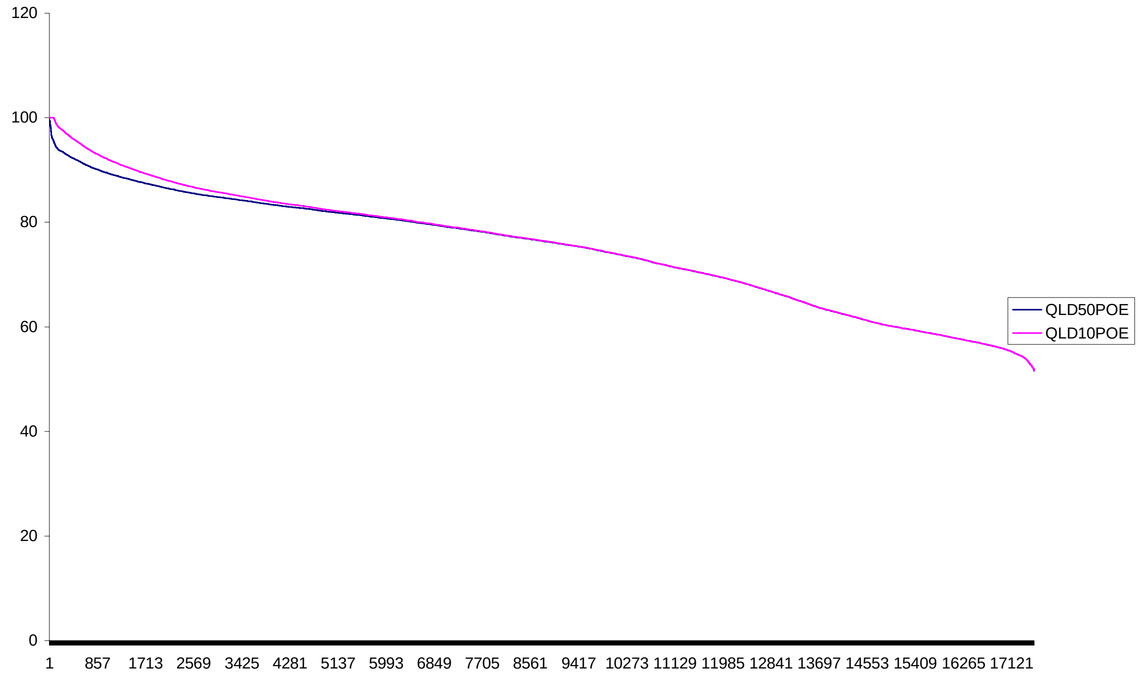


Figure 7: Normalised Load Shape for South Australia

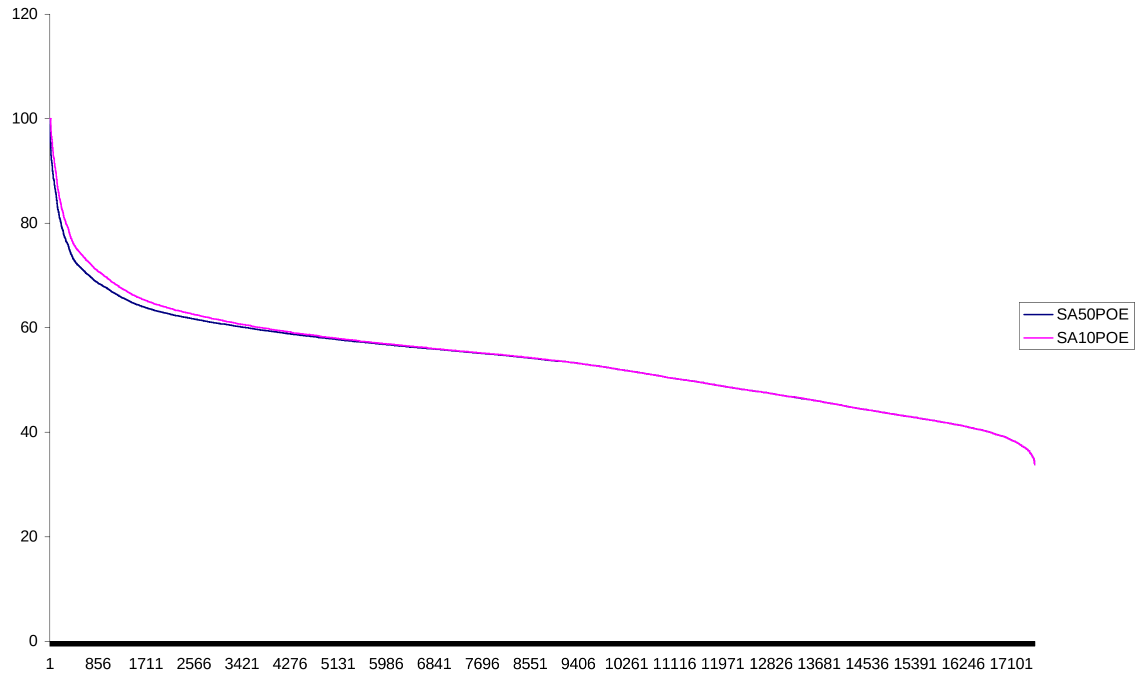
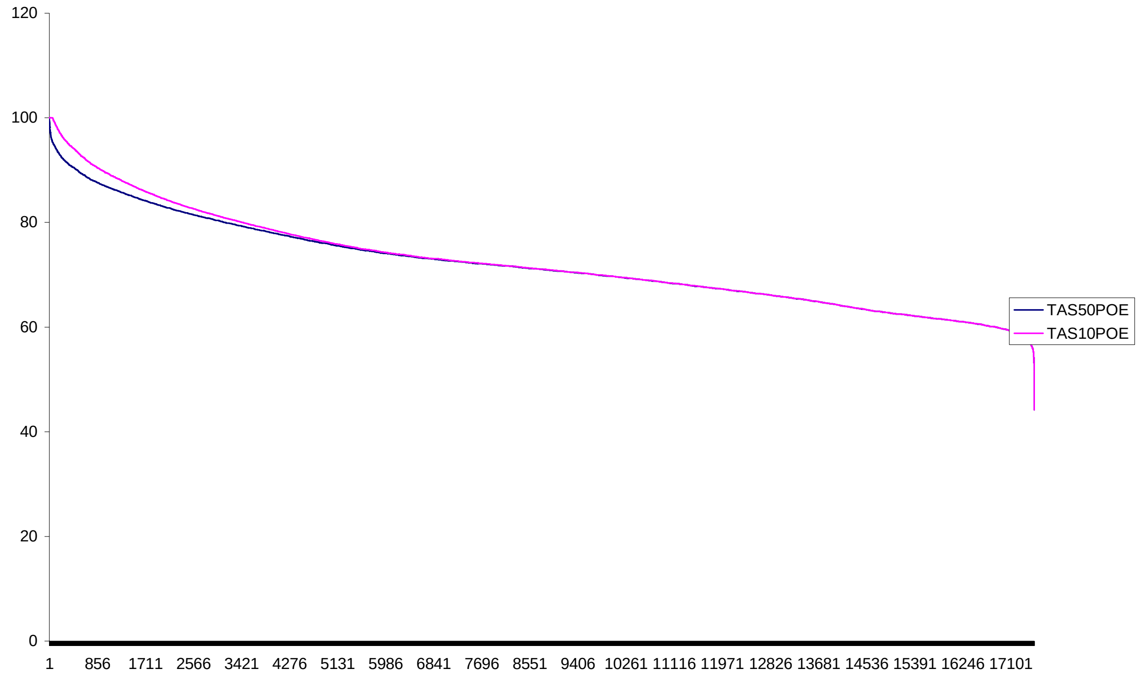


Figure 8: Normalised Load Shape for Tasmania



A.3.3 Supply Capacity

CEMOS uses the supply system characteristics including committed plants shown in Table 2, and the investment costs for (generic) new investment shown in Table 3. The short run marginal cost of generation calculated as variable fuel and operating expenses forms an input to the formation of strategic bids. Table 4 describes the outage statistics that are considered.

Over time, additional generation will need to be added to meet demand. The nature and timing of new entry will depend on a variety of factors including the level of competition in the NEM. Our assumptions on strategic bidding recognise the effect of competitive new entry on the market behaviour of existing generators, and generally drive prices down to long run marginal cost of new entrant plants reflecting the need for new investors to recover capital cost. We have presented the optimal capacity entry outcomes as part of the model results in the next section.

Existing Generation Capacity

Table 2: Existing Generation Characteristics

Station	Type	Capacity (MW)	Variable O&M ($/MWh)	Heat Rate (MJ/MWh)
AGLHal	OCGT	188	2.9	12000
AGLSom	OCGT	152	2.9	12000
Angaston	OCGT	40	2.9	12000
Anglesea	Sub_Cr_brownCoal	156	3	15150
Bairnsdale	OCGT	90	2.9	10000
Barcaldine	CCGT	49	1.8	8372
BarronGorge	Hydro	60	0	1000
Bayswater	Sub_Cr_BlkCoal	2760	3	10000
BellBay	Steam_Gas	228	1.8	12000
BellBayThree	OCGT	108	2.95	10588
Blowering	Hydro	80	0	1000
Braemar	OCGT	450	2.9	12000
CallideA	Sub_Cr_BlkCoal	0	3	11250
CallideB	Sub_Cr_BlkCoal	700	3	9972
CallidePP	Sub_Cr_BlkCoal	920	3	9114
Collinsville	Sub_Cr_BlkCoal	188	3	12000
DartMouth	Hydro	150	0	1000
DryCreek	OCGT	141	2.9	12000
Eildon	Hydro	120	0	1000
Eraring	Sub_Cr_BlkCoal	2640	3	10000
Gladstone	Sub_Cr_BlkCoal	1680	3	10227
Guthega	Hydro	60	0	1000
Hazelwood	Sub_Cr_brownCoal	1600	3	15051
HumeNSW	Hydro	29	0	1000
HumeV	Hydro	29	0	1000
HVGTS	OCGT_Oil	51	2.9	12000
JeeralangA	OCGT	232	2.9	11250

Station	Type	Capacity (MW)	Variable O&M ($/MWh)	Heat Rate (MJ/MWh)
JeeralangB	OCGT	255	2.9	11250
Kareeya	Hydro	88	0	1000
KoganCreek	Sup_Cr_BlkCoal	763	3	9200
Ladbroke	OCGT	84	2.9	10588
LavertonNorth	OCGT	340	2.9	12000
Liddell	Sub_Cr_BlkCoal	2100	3	10588
LoyYangA	Sub_Cr_brownCoal	2190	3	12906
LoyYangB	Sub_Cr_brownCoal	1032	3	12836
MackayGT	OCGT_Oil	34	2.9	12857
McKay	Hydro	160	0	1000
MillmerranPP	Sub_Cr_BlkCoal	860	3	9474
Mintaro	OCGT	86	2.9	12000
Morwell	Sub_Cr_brownCoal	148	3	15150
MtPiper	Sub_Cr_BlkCoal	1400	3	10000
MtStuart	OCGT_Oil	294	2.9	11250
Munmorah	Sub_Cr_BlkCoal	600	3	11250
Murray	Hydro	1535	0	1000
Newport	Steam_Gas	510	1.8	12000
NorthernPS	Sub_Cr_brownCoal	540	3	11415
NSWWind	Wind	17	0	1000
Oakey	OCGT_Oil	320	2.9	11250
Osborne	Cogeneration	190	1.8	8571
PlayfordB	Sub_Cr_brownCoal	240	3	15652
PortLincoln	OCGT_Oil	50	2.9	13846
PPCCGT	CCGT	474	1.8	7660
QLDWind	Wind	12	0	1000
Quarantine	OCGT	92	2.9	11250
Redbank	Sub_Cr_BlkCoal	150	3	10909
RomaGT	OCGT	68	2.9	10909

Station	Type	Capacity (MW)	Variable O&M ($/MWh)	Heat Rate (MJ/MWh)
SAWind	Wind	388	0	1000
Shoalhaven	Hydro	240	0	1000
Smithfield	Cogeneration	162	1.8	8780
Snuggery	OCGT	51	2.9	12857
Stanwell	Sub_Cr_BlkCoal	1440	3	9890
SwanbankB	Sub_Cr_BlkCoal	480	3	10588
SwanbankE	CCGT	350	2.9	7200
Tallawarra	CCGT	434	1.82	7299
Tarong	Sub_Cr_BlkCoal	1400	3	10227
TASHydro	Hydro	2280.9	0	1000
TasWind	Wind	142	0	1000
TNPS1	Sub_Cr_BlkCoal	443	3	9114
TorrensA	Steam_Gas	504	1.8	13029
TorrensB	Steam_Gas	824	1.8	12000
Tumut3	Hydro	1500	0	1000
Upptumut	Hydro	616	0	1000
ValesPt	Sub_Cr_BlkCoal	1320	3	10141
ValleyPower	OCGT	336	2.9	12000
VICWind	Wind	132	0	1000
Wallerawang	Sub_Cr_BlkCoal	1000	3	10909
WestKiewa	Hydro	72	0	1000
Wivenhoe	Hydro	500	0	1000
Yabulu	OCGT_Oil	238	2.9	7200
Yallourn	Sub_Cr_brownCoal	1487	3	13900

Note: Sub_Cr_BlkCoal = Sub critical black coal. Sub_Cr_brownCoal = Sub critical brown coal

Data Source: Report to NEMMCO by ACIL Tasman, 2005.

New Generation Capacity

Table 3: New Generation Characteristics

Station	Type	Annualised Capital Cost[2] ($/MW/year)	Variable O&M ($/MWh)	Heat Rate (MJ/MWh)
NSW_CCGT_2005	CCGT	104403	1.82	7299
QLD_CCGT_2005	CCGT	104403	1.82	7299
SA_CCGT_2005	CCGT	104403	1.82	7299
TAS_CCGT_2005	CCGT	104403	1.82	7299
VIC_CCGT_2005	CCGT	104403	1.82	7299
NSW_Sup_Cr_BlkCoal_2005	Sup_Cr_BlkCoal	113563	2.88	9114
QLD_Sup_Cr_BlkCoal_2005	Sup_Cr_BlkCoal	113563	2.88	9114
VIC_Sup_Cr_brownCoal_2005	Sup_Cr_brownCoal	156167	2.88	12544
NSW_Wind_2005	Wind	192603	0	1000
QLD_Wind_2005	Wind	192603	0	1000
SA_Wind_2005	Wind	192603	0	1000
TAS_Wind_2005	Wind	192603	0	1000
VIC_Wind_2005	Wind	192603	0	1000
NSW_OCGT_2005	OCGT	71423	2.95	10588
QLD_OCGT_2005	OCGT	71423	2.95	10588
SA_OCGT_2005	OCGT	71423	2.95	10588
TAS_OCGT_2005	OCGT	71423	2.95	10588
VIC_OCGT_2005	OCGT	71423	2.95	10588
NSW_Smallhydro_2005	Smallhydro	219631	7	1000
QLD_Smallhydro_2005	Smallhydro	219631	7	1000
TAS_Smallhydro_2005	Smallhydro	219631	7	1000
VIC_Smallhydro_2005	Smallhydro	219631	7	1000

2 Using a WACC of 8.84% and 30 year plant life assumptions (Source: ACIL Tasman report, Table 41 for detailed assumptions on the WACC)

Table 4: Generator Outage Statistics

			Historic Average			
			Availability	**Forced Outage Rate**	**Maintenance Outage Rate**	**Partial Outage Rate**
Thermal Coal	>500 MW	Average*	89.7%	2.1%	1.1%	7.1%
		Median	92.9%	1.5%	0.6%	4.9%
	>200 MW	Average	90.7%	4.2%	1.6%	3.4%
		Median	92.3%	4.2%	0.9%	2.6%
	<200 MW	Average	75.4%	7.2%	1.7%	15.7%
		Median	83.6%	5.8%	1.4%	9.2%
Thermal Gas/Oil	All sizes	Average	89.8%	2.4%	2.8%	5.1%
		Median	91.7%	1.1%	4.4%	2.8%
OCGT	All sizes	Average	90.7%	3.1%	1.8%	4.4%
		Median	95.2%	0.9%	0.6%	3.3%
CCGT	All sizes	Average	94.1%	0.4%	0.7%	4.8%
		Median	96.3%	0.6%	0.0%	3.0%
Hydro	All sizes	Average	92.4%	0.8%	1.5%	5.3%
		Median	94.8%	0.4%	1.0%	3.9%
Weighted Average All Plants		Average	90.3%	2.6%	1.4%	5.7%
		Median	94.9%	1.1%	0.8%	3.2%

Source: Energy Supply Association of Australia, 2006

A.3.4 Fuel Prices

Fuel price projections are based on the estimates developed by ACIL Tasman in 2005 in its report to NEMMCO/IRPC. These are shown in Figure 9 to Figure 11.

Figure 9: Gas Price by Region: 2008-2017 ($/GJ)

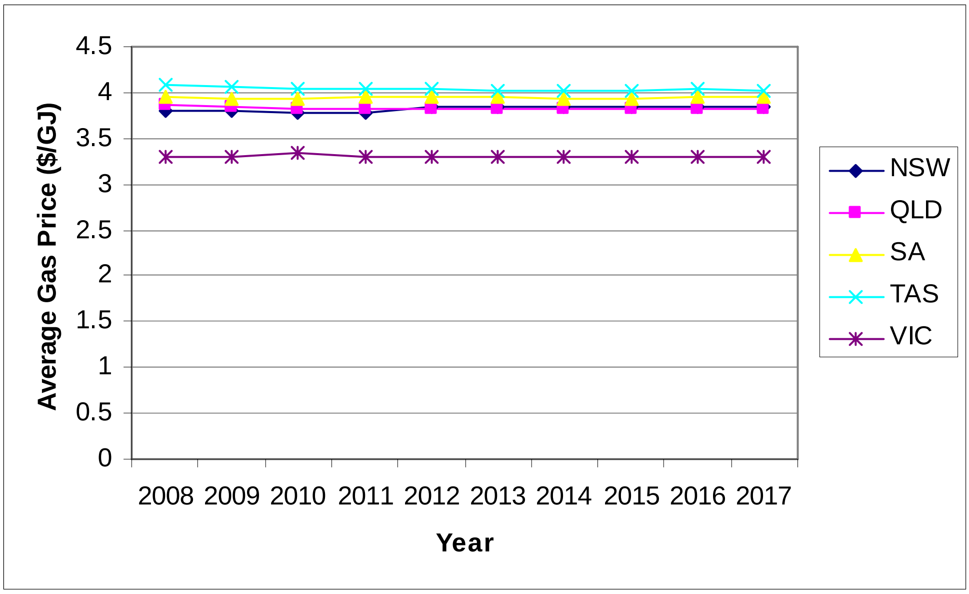


Figure 10: Black Coal Price by Region: 2008-2017 ($/GJ)

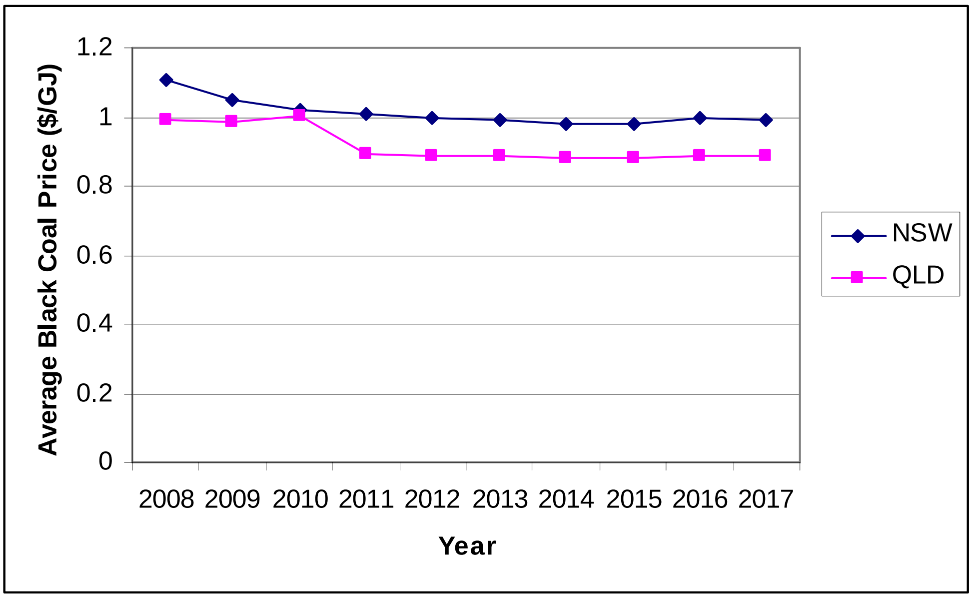
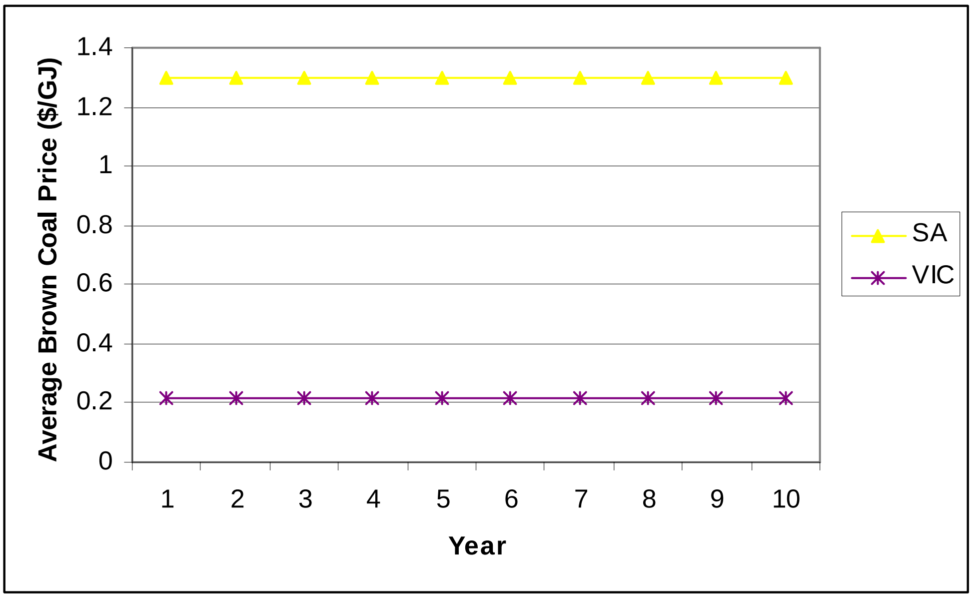


Figure 11: Brown Coal Price by Region: 2008-2017 ($/GJ)



A.3.5 Interconnection Capacity

Transmission upgrades noted in the SOO/ANTS have been included, and interconnection limits from the SOO/ANTS have been applied; these are listed in Table 5. The initial optimisation derived by the modelling for augmenting generation within the constraints of the transmission network supplied as input is inherently conservative. Interim results were reviewed to examine the potential for augmentation during the period of the study. Additional peaking capacity has been added where profitability measures after accounting for volatility of load and generation performance have shown further capacity would be commercially viable. Augmentation of transmission has been assumed where sustained differences in price or sustained regional differences in USE were observed. These differences indicate the potential for reliability or market based upgrades of interconnectors. The upgrades have not been subject to comprehensive cost benefit tests and thus are indicative only, but nevertheless they are adequate for the purposes of this study.

Table 5: Interconnecter Capacities (Existing and SOO/ANTS)

Interconnector	Year	From	To	Forward Capacity (MW)	Reverse Capacity (MW)
BassLink	Existing	TAS	VIC	600	480
N_Q_MNSP1	Existing	NSW	QLD	152	196
NSW1_QLD1	Existing	NSW	QLD	589	1078
NSW1_QLD1 Expansion	2014	NSW	QLD	500	500
SNOWY1	Existing	SNY	NSW	3559	1150
V_S_MNSP1	Existing	VIC	SA	220	214
V_SA	Existing	VIC	SA	460	300
V_SA2	2009	VIC	SA	170	0
V_SN	Existing	VIC	SNY	1313	1842
V_SN2	2009	VIC	SNY	0	201
V_SN3	2009	VIC	SNY	200	180

Source: ANTS 2006 and ANTS 2005 (VIC_SA2 based on ANTS 2005)

A.4 Discussion of Results

The following sections discuss the model results for each of the Options A to D that were introduced in section 1:

- **Status Quo (Option A)**: These scenarios closely resemble the current energy only market design and have the level of VOLL set at $10,000/MWh (in real terms), and two variations from that figure;

- **Option B**: A RAS requirement set to achieve the same level of USE as in the status quo;

- **Option C**: Standby capacities growing from 40 MW in 2008 to 309 MW in 2017 as shown in Figure 30 are considered in this scenario; and

- **Option D**: Reliability options are simulated assuming an option of $71,000/MW/year which is in the same order as the annualised capital cost of a new peaking generator. We have also assumed that this scenario will render the energy market highly competitive akin to a 100% contracting situation.

All analysis assumes VoLL is maintained at the specified levels in real terms, that is, increased in line with inflation. Clearly if VOLL were maintained at the at those levels in absolute terms as it has been in the NEM then over time the ability of the market to attract new investment will fall and USE will progressively rise.

A.5 Status Quo and Sensitivity to VoLL

A.5.1 Overview

Option A was formed from the current design (status quo) of the NEM with variations in the level of VoLL. Two variations from the status quo are considered – with VOLL set at a lower level of $7,500/MWh, and at a higher level of $12,500/MWh.

Table 6 presents a high-level summary of the status quo cases. Figure 12 and Figure 13 show the NEM-wide installed capacity and peak demand for the scenarios. Key observations from these plots and the high-level summary include:

- An increase in VoLL of $2,500/MWh attracts new capacity and incrementally lowers USE by approximately 0.0003%, on average. Energy from the increased total capacity of peaking plant grows slightly but is spread across a proportionally greater capacity, and thus the average utilisation is slightly lower;

- On the other hand, a decrease in VoLL of $2,500/MWh discourages some investment and increases the USE by approximately 0.0004% on average. Generators effectively have a lower cap against which to bid, and although there is generally less capacity in the market, average NEM prices go down slightly – including the prices received by base load units as well as peaking investors. However, the average utilisation of the peaking units rises marginally; and

- In all cases, utilisation of base load generation is largely unaffected and dispatched to close to maximum potential.

Table 6: Summary of Status Quo Scenarios – Sensitivity to VoLL

	$7,500/MWh (real)	$10,000/MWh (real)	$12,5000/MWh (real)
USE (long term average)*	0.0022%	0.0018%	0.0015%
Peak Generation: Utilisation Factor (%) for new entrant OCGT	9.2%	9.1%	9.0%
NEM Peak Generation (NEM wide average): Annual Average Price ($/MWh) received by new entrant OCGT	170	188	201
NEM Peak Generation (NEM wide average revenue:cost ratio for new entrant OCGT	1.25	1.38	1.48
Base Generation (new entrant coal): Utilisation Factor (%)	90%	90%	90%
Base Generation: Annual Average Price ($/MWh) received by new entrant coal	33.2	35.0	36.3

Note: Average outcomes over 2008-2017, calculated as a weighted average of 10% and 50% POE cases using a 30% and 70% weight, respectively.

Figure 12: Installed Capacity and Peak Demand

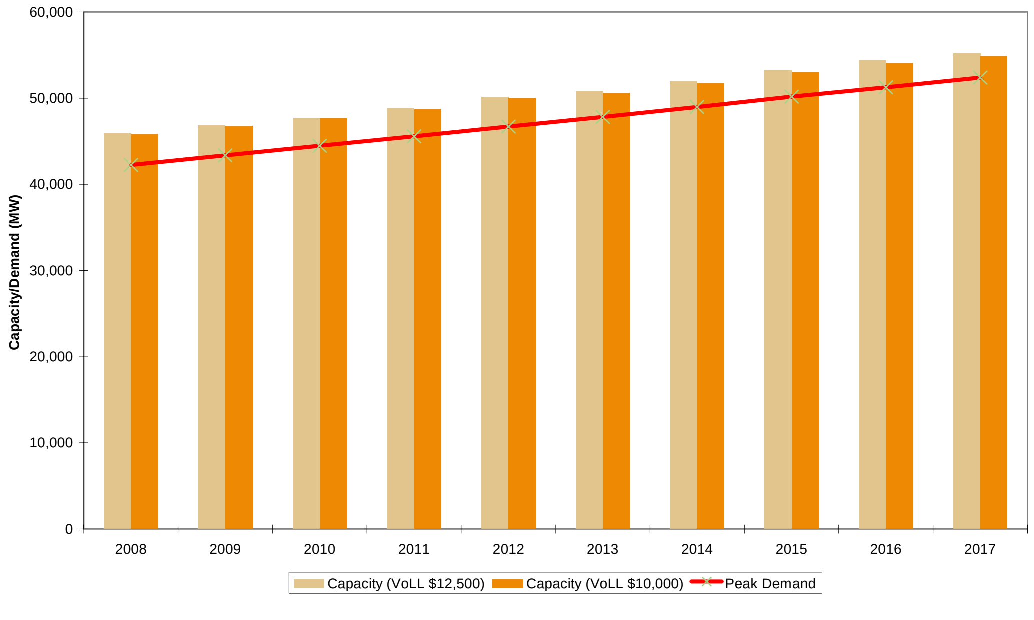
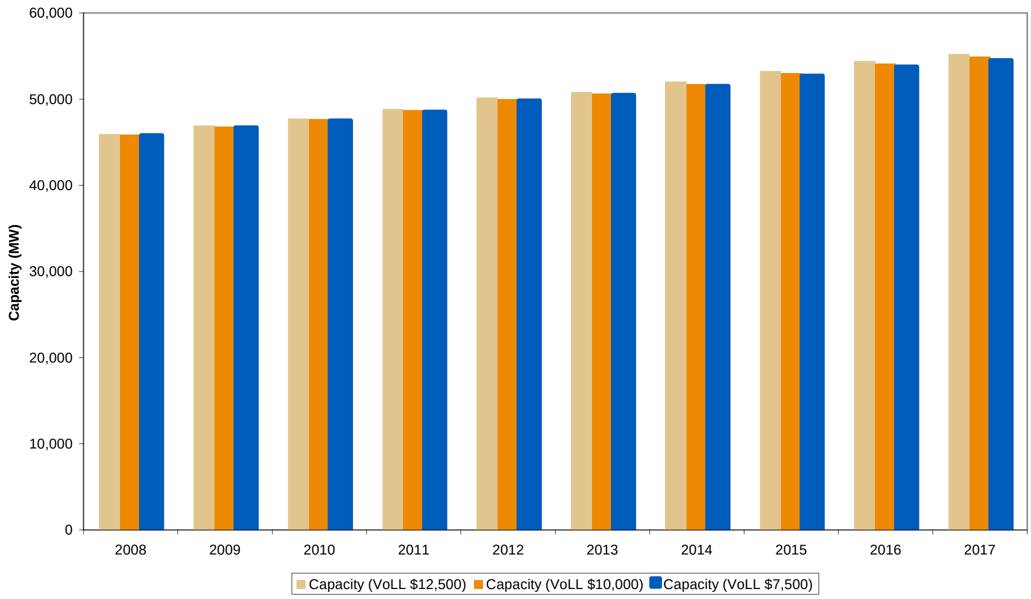


Figure 13: Installed Capacity – All VoLL Sensitivity Cases



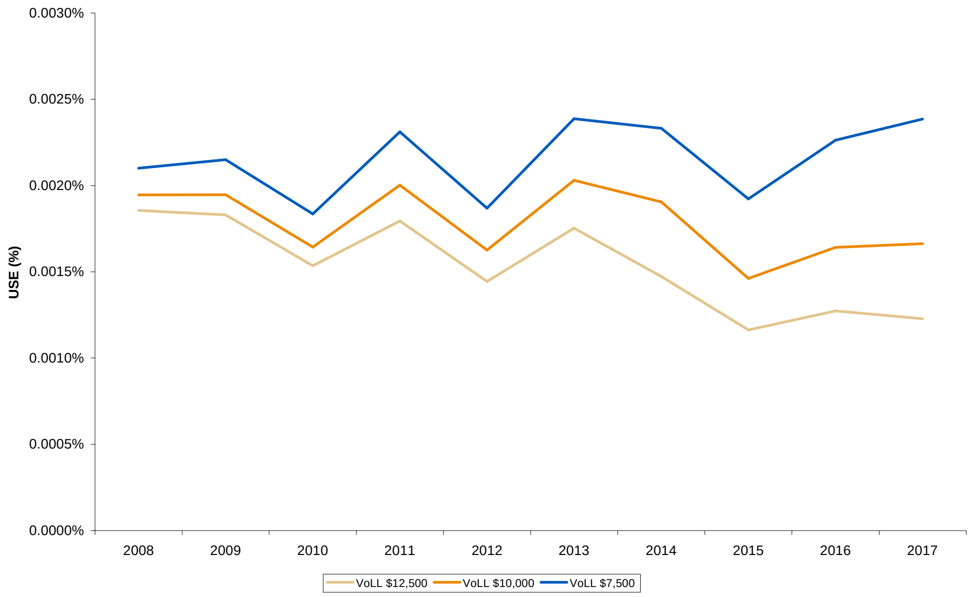
A.5.2 Annual USE – NEM Wide

Figure 14 shows the regional average USE over the period of the study. Annual USE fluctuates, reflecting the variation in supply demand as additional plant is added.[3] USE for the status quo (VoLL of $10,000/MWh) generally declines over the years, consistent with expectations that as the system grows and more generating units are installed the system becomes inherently more reliable. A higher VoLL attracts more investment and therefore accelerates this trend, especially after 2010.[4] A lower VoLL makes the system more susceptible to outage risks because of lower peaking investment, and the year-on-year fluctuation in USE dominates the declining trend.

3 USE varies non-linearly with the spare capacity and can be extremely sensitive to relatively small variations in spare capacity and change in generation mix. A trend that shows significant variation in year-to-year USE, as well as regional USE as discussed later, is therefore to be expected.

4 This is of course achieved at a higher cost, and the implied marginal cost of reducing USE (i.e. $/MWh of USE) may be high reflecting more additional peaking investment than is warranted.

Figure 14: Annual USE for Status Quo Scenarios – Sensitivity to VoLL



Note: NEM-wide USE.

A.5.3 Regional USE Distribution

Figure 15 to Figure 17 show the regional USE distributions for each of the VoLL scenarios.

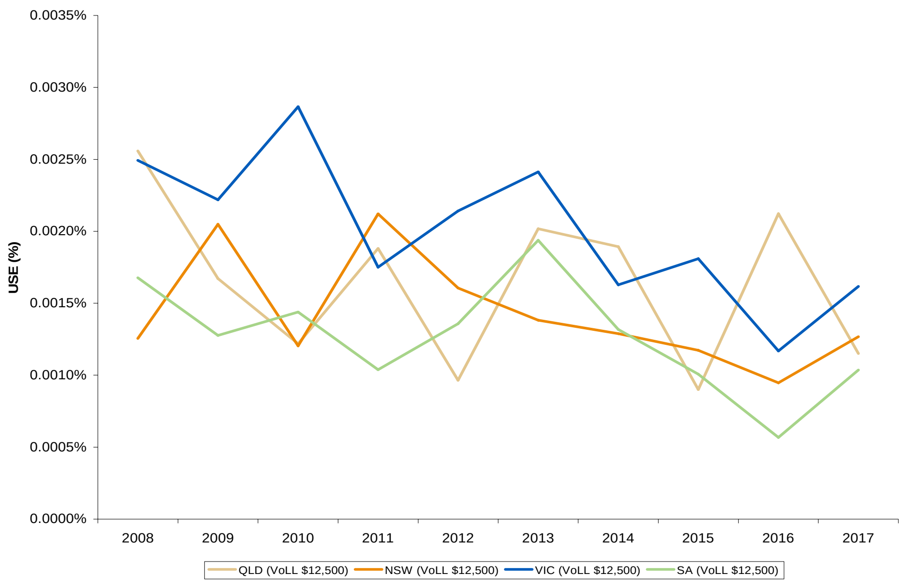
Considerable care should be taken in interpreting these regional results. In particular, the timing of peaks and troughs for any single region and the relativity between regions at any given time should be regarded as indicative only. During the course of the analysis it was evident that small shifts in the timing and location of investment in generation and in transmission can lead to significant reordering of the relative results for the regions. Further, the results here are the average across simulations of many years, and individual years may in practice be quite different.

The key conclusion that should be drawn from the regional USE statistics is that a regional balance can emerge from the market, at least within the assumption of the market being allowed to function unimpeded by external influences that the main body of the report highlights are in practice a key limitation.

The figures show that at a higher level of VoLL, the general declining trend of USE is observed for all regions, although there is a significant variation in USE level across the regions and over the years. Smaller regions such as SA and regions with relatively high sensitivity to temperature with large base load units such as Victoria are more prone to outages if peaking investment is lacking. This is observed for Victoria in particular, which shows a significant shift in annual trend of USE across the VoLL scenarios. It should be noted that the simulations used in this study did not consider hydrological risks, and therefore the median hydrology assumed for hydro-based generation on NEMMCO data does not show USE in Tasmania – that is, reliability in Tasmania is expected to be dominated by capacity expansion driven by long term energy assurance, whereas the other regions are driven by capacity limitations.

Figure 15: Annual USE for Status Quo Scenarios by Region (VoLL of $12,500/MWh)

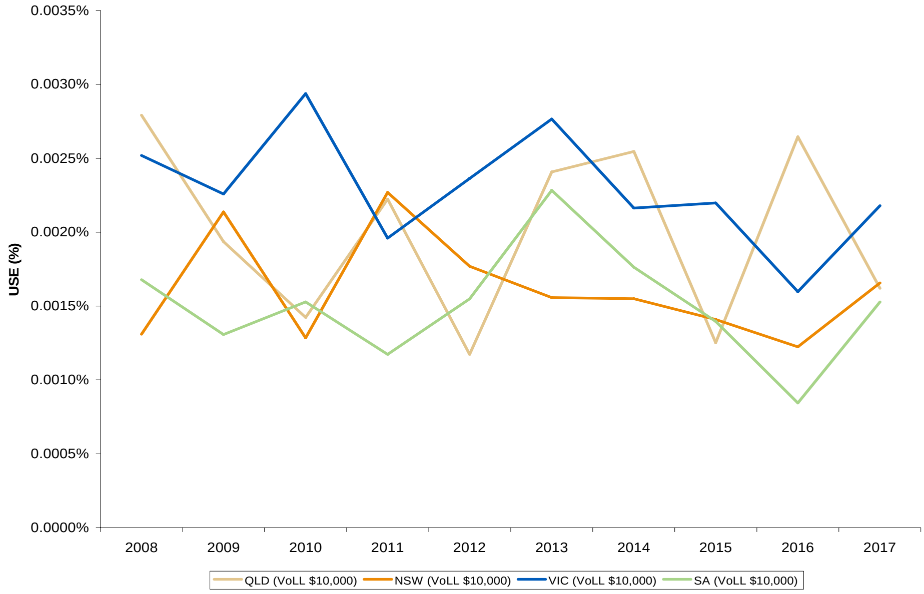
Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.



Note: TAS has zero USE and is not shown on the plot.

Figure 16: Annual USE for Status Quo Scenarios by Region (VoLL of $10,000/MWh)

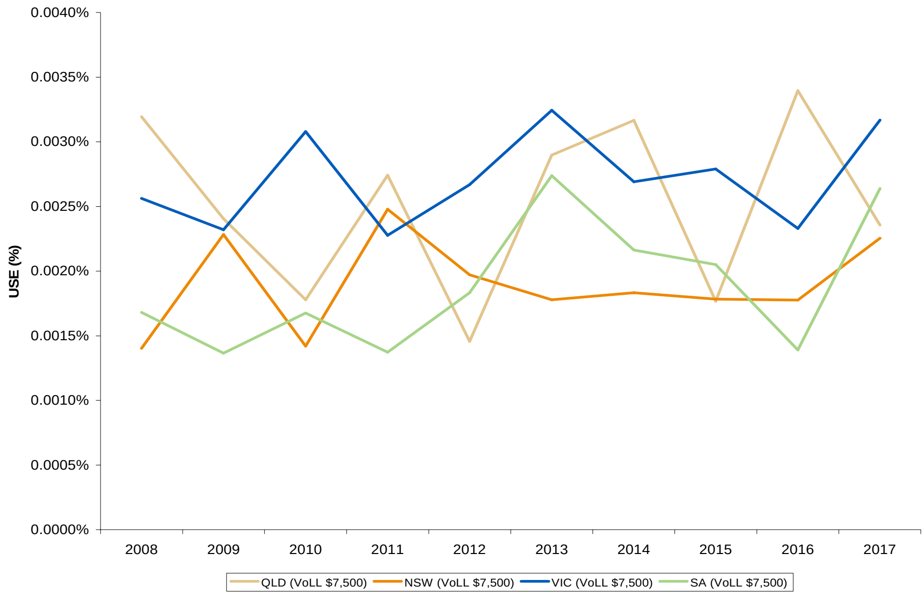
Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.



Note: TAS has zero USE and is not shown on the plot.

Figure 17: Annual USE for Status Quo Scenarios by Region (VoLL of $7,500/MWh)

Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.

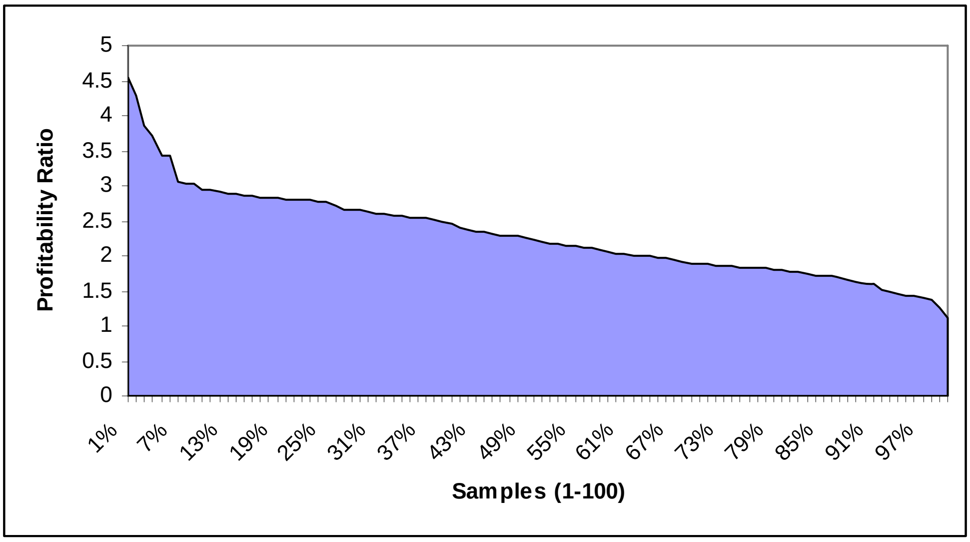


Note: TAS has zero USE and is not shown on the plot.

A.5.4 Profitability of Peaking Investment

Profitability of new entrant open cycle gas turbines (measured in terms of the ratio of revenue and cost inclusive of annualised capital costs) is the most sensitive of all plant types. Profitability can vary widely across different outage scenarios, with extremely high profitability in situations where deep outages occur relative to lower rates of outage. Figure 19 illustrates the magnitude of this variability for a new entrant OCGT in SA in 2010 for the status quo scenario. In less than 5% of the samples, profitability was observed to be over 4, and in 100% of the samples the OCGT generally broke even (ratio of 1 or more). On average, a profitability ratio of 2.30 is achieved.

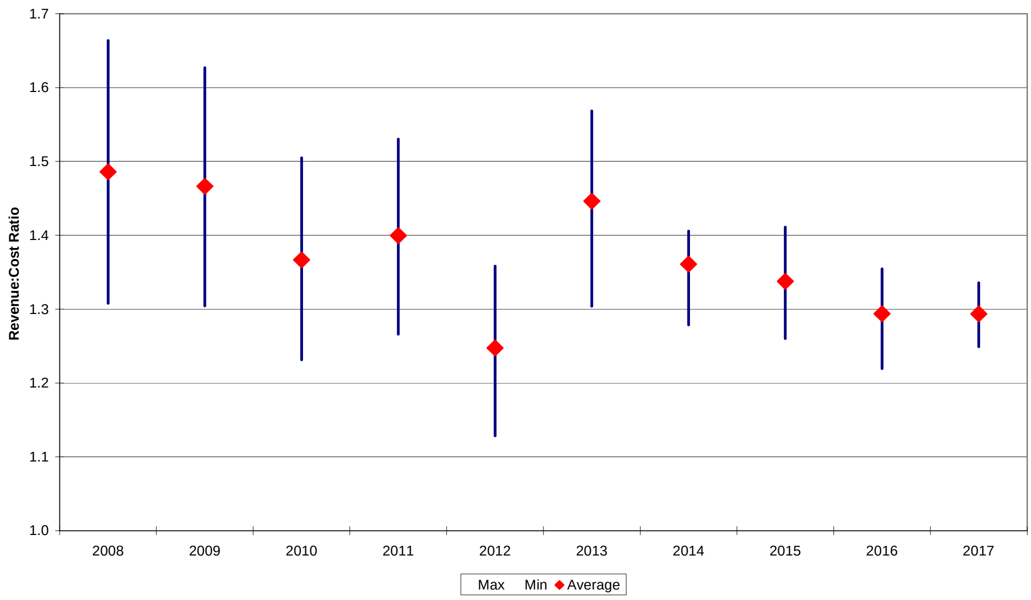
Figure 18: Typical Distribution of Profitability Across 100 Random Outage Samples for a New Entrant OCGT in SA in 2010



Note: Status Quo (VoLL of $10,000)

Figure 19 shows the range of profitability ratio achieved by *all* new entrant OCGT units NEM-wide. They generally lie between 1 and over 1.7 across the range of VoLL, but vary widely across the sensitivities and over the years. This generally reflects the significant uncertainty in pool price outcomes expected in an energy only market.

Figure 19: Annual profitability of New Entrant Peaking Generation – Range Across VoLL Sensitivity



Note: Profitability is calculated as the weighted average of 10% and 50% POE cases using a 30% and 70% weight, respectively.

A.5.5 NEM Prices

The average market price will be affected by counteracting influences, as a result of the introduction of the different mechanisms. Where VoLL is increased and where a RAS payment is added to the market, the potential peak price will rise. However, the additional capacity that such changes are designed to elicit will increase competition, particularly as reserves fall, and thus will tend to dampen prices before shortfall occurs.

The manner in which model inputs are created can make a significant difference to the outcomes, for example how the high-priced bids are formed in the Cournot modules[5] and assumptions about relative costs of plant and transmission. Figure 20 to Figure 24 present price outcomes for scenarios, and show that prices increase when VOLL is increased, which in turn increases profitability for peaking generation.[6] This result suggests that the ability of generators to bid at least a portion of their capacity at the higher allowed maximum prices dominates the effect of greater competition in the peak generation segment due to increased peaking entry.

Furthermore, an increase in VoLL and higher competition may also induce a change in capacity mix that might also contribute to a depressing of prices that the results in Figure 20-Figure 24 do not consider. We have constructed an alternative scenario for VoLL of \$12,500/MWh, wherein higher level of competition (and hence less aggressive bidding) is assumed in the face of more peaking as well as base load entry.[7] Prices for this alternative scenario with VoLL at \$12,500/MWh are compared with the status quo \$10,000/MWh and \$12,500/MWh scenarios in Figure 25. The results show that average prices with a higher VoLL can in fact be lower, depending on a range of assumptions we make on bidding behaviour.

In reality, none of these effects may be the dominant issue – as external (exogenous) factors are likely to have a much greater impact on investment decisions owing to the relatively extreme sensitivity of investment viability to factors that affect prices and utilisation of plant whose main purpose is to support reliability.

Thus, when modelling price effects for the CRR, we focus on the relativity between the different options.

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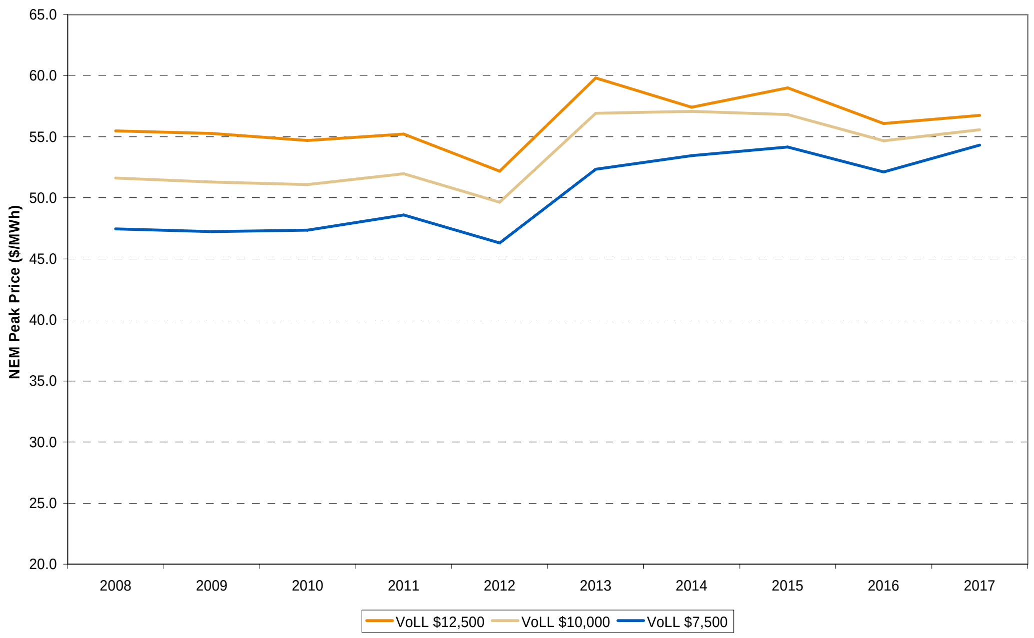
5 All models employ some form of input dependant modelling in this regard. The most common is to benchmark against previous bidding patterns and assume that these apply into the future after changes to the settings have been made. This is the approach NEMMCO uses based on back-casting and contract optimisation prepared by Intelligent Energy Systems – http://www.nemmco.com.au/transmission_distribution/410-0069.pdf

6 See Figure 19 for profitability of new entrant OCGTs.

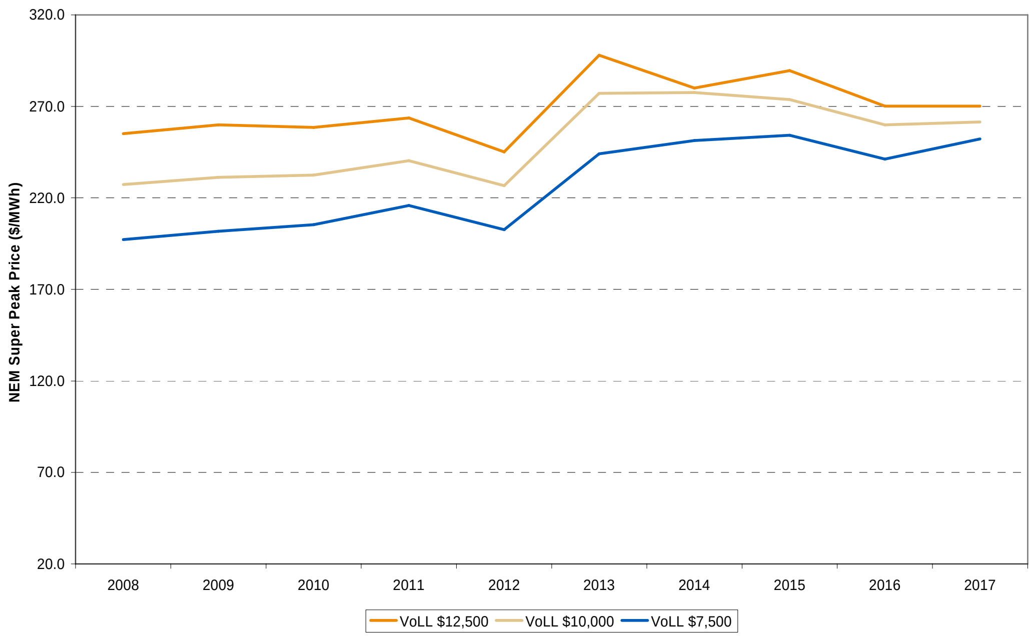
7 The new entrant peaking and base load entrants have lower profitability compared to the status quo \$12,500/MWh scenario, but the profitability ratio is still adequate for entry to occur in the alternative scenario.

Figure 20: NEM Peak Price ($/MWh)



Note: Prices represent weighted average of 10% and 50% POE cases using a 30% and 70% weight, respectively. NEM peak definition covers all working hours during weekdays as per AFMA definition.

Figure 21: NEM Super-Peak Price ($/MWh)



Note: Super-peak refers to the top 50 hour prices for all regions.

Figure 22: NEM Average Price (Time Weighted) $/MWh

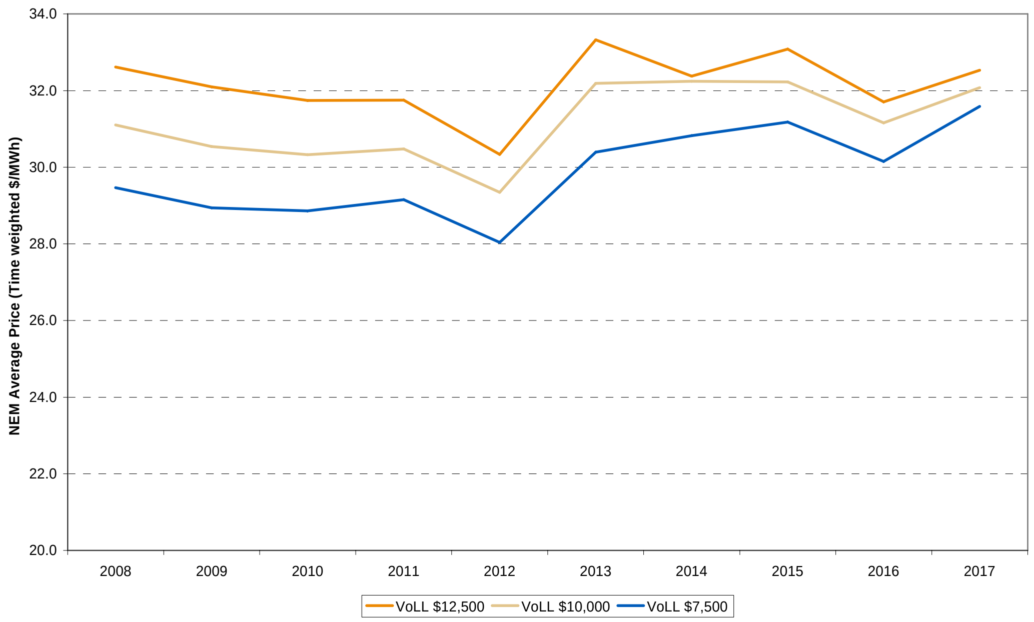


Figure 23: NEM Super-Peak Prices – Range Across Scenarios ($/MWh)

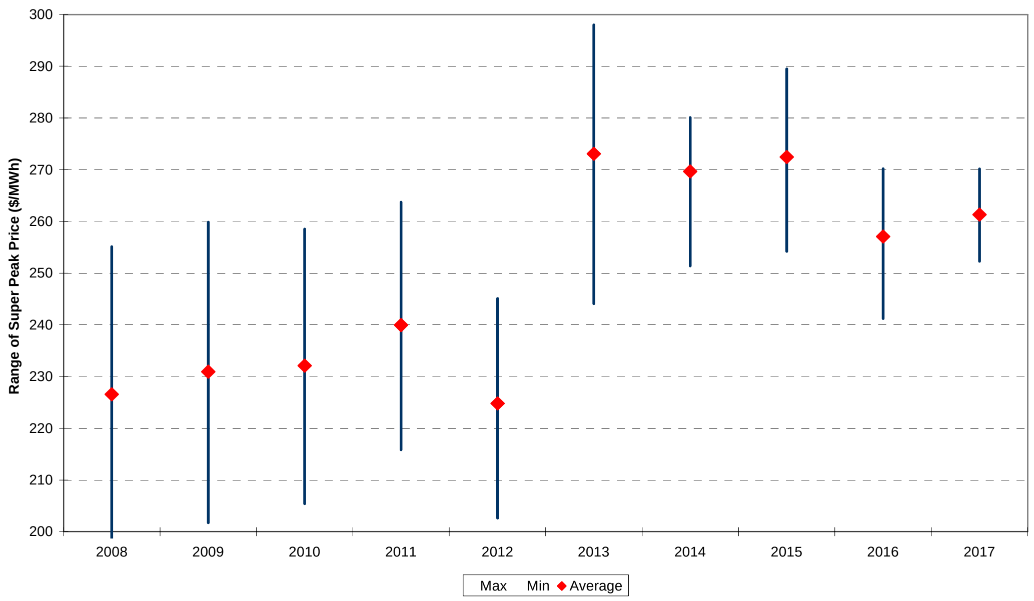


Figure 24: Regional Peak Prices – Range Across Regions $/MWh

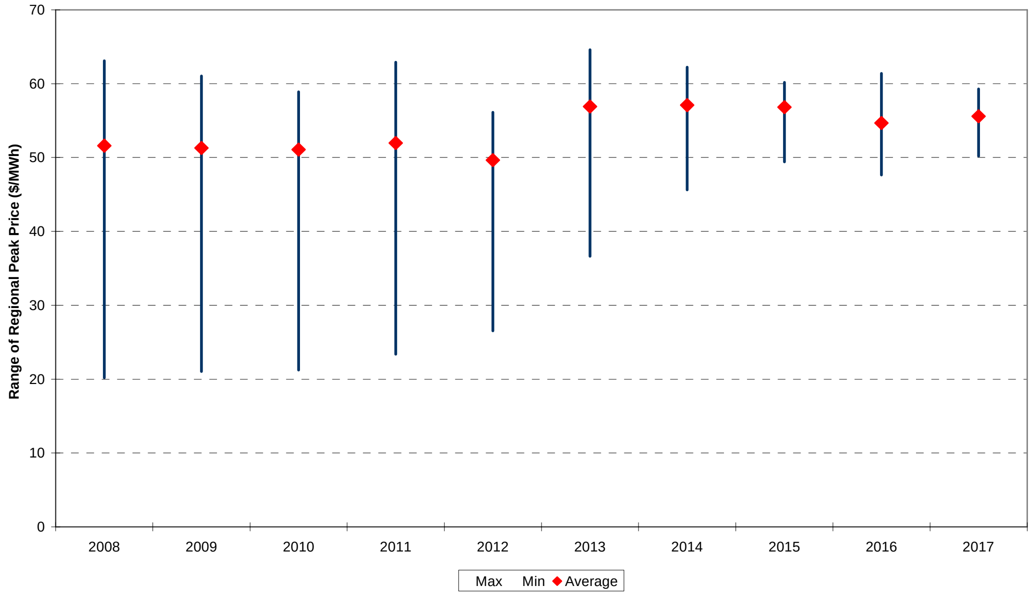
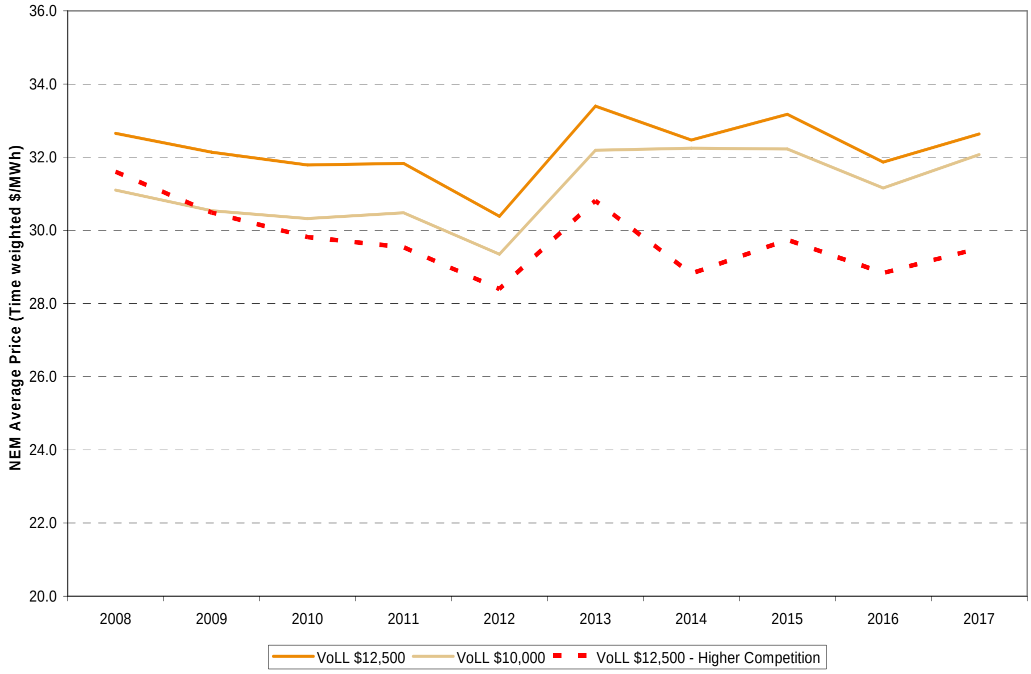


Figure 25: Comparison of Prices With higher VoLL and Different Level of Competition (and Capacity Mix)



A.6 ALTERNATIVE MARKET DESIGN OPTIONS

A.6.1 Overview of Results

The discussion so far has considered variations to VoLL in the status quo. This section discusses the outcomes from modelling of broader changes to the NEM design under options B, C and D. Table 7 provides a summary of the key results including USE, prices, and profitability. These options represent more significant departures from the current arrangements, and hence may involve very different dispatch/pricing and reliability outcomes.

To provide a uniform basis for comparison, we designed the analysis to compare outcomes on the basis that VoLL remained at $10,000/MWh in real terms. We have assumed the same treatment of VoLL as we did in the analysis of the status quo design in section A.5, and assumed VoLL is maintained at the specified levels in real terms, that is, increased in line with inflation. Clearly if VOLL were maintained at the at the same level in absolute terms, as it has been in the NEM, then over time the ability of the market to attract new investment will fall and USE will progressively rise.

In Options B and C, the RAS and standby contracts provide additional revenue to new investment, which leads to lower USE but higher costs.

In option D, where the Reliability Option fee is intended to replace the payment generators receive from market prices in excess of SRMC, the level of VoLL was set to $3,000/MWh (real) – the level of VoLL under this option has less impact on reliability under this alternative.

Figure 26 and Figure 27 plot key parameters for the different options. The following sections provide additional detail on the results for each option.

Table 7: Summary of Status Quo and Alternative Market Design Results

	Status Quo		Alternative Market Design		
	$10,000/MWh (Real)	$12,500/MWh (Real)	RAS	Standing Reserve	Reliability Options
USE	0.0018%	0.0015%	0.0015%	0.0015%	0.0015%
NEM Average Energy Price	31	32	32 (Excludes RAS cost)	31 (Excludes Contract Costs)	20 (Excludes Reliability Option Costs)
NEM Peak Generation (NEM-wide Average): Annual Average Price Received $/MWh	188	201	193	187	50 (Excludes Reliability Option Fees)
NEM Peak Generation NEM-wide Average Revenue:Cost Ratio	1.38	1.48	1.51	1.37	0.95
NEM Peak Generation NEM-wide Standard Deviation of Average Revenue:Cost Ratio	0.41	0.46	0.39	0.39	0.05
NEM Base Generation NEM-wide Standard Deviation of Average Revenue:Cost Ratio	0.19	0.22	0.19	0.19	0.01
Base Generation: Annual Average Price ($/MWh)	35.2	36.4	35.5	35.5	33.5* (Assumes 100% energy contracts at $35/MWh)

* Reflects primarily the contract price of $35/MWh for bulk of the generation but also some deviation of generation from contracted level compensated at lower pool price.

Figure 26: Summary of USE and Reserve Margin (50% POE Demand) by Design Option

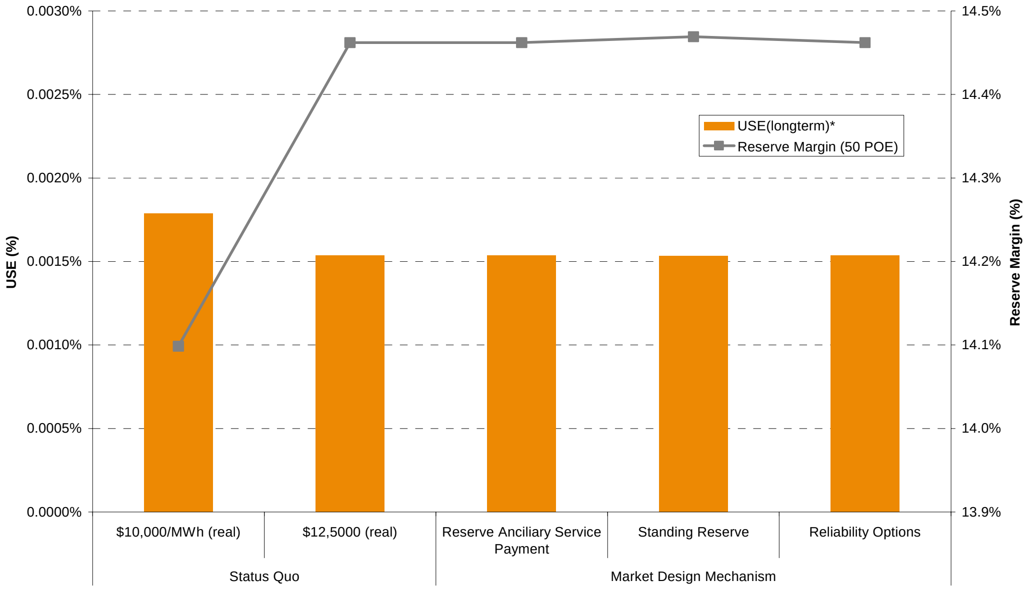
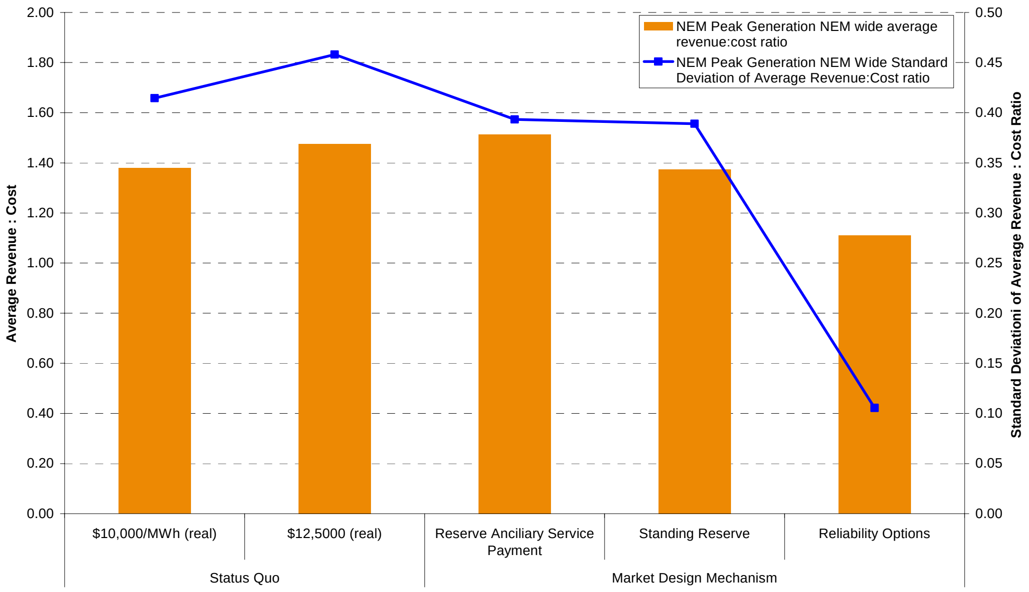


Figure 27: Revenue:Cost Ratio and Variability by Design Option



Typical payments for different parts of the RAS price distribution curve are shown in Table 8.

Table 8: Average RAS Payments Modelled (2008-2017)

Super-Peak RAS Price ($/MWh)	Peak RAS Price ($/MWh)	Shoulder Peak RAS price ($/MWh)
2780	690	90

Figure 28 and Figure 29 compare the profitability from the RAS with that of the status quo. They also show the standard deviation or variability of the profitability ratio and further confirm that RAS yields not just higher but also more stable revenue to the OCGTs.

Figure 28: RAS: Profitability Comparison to Status Quo

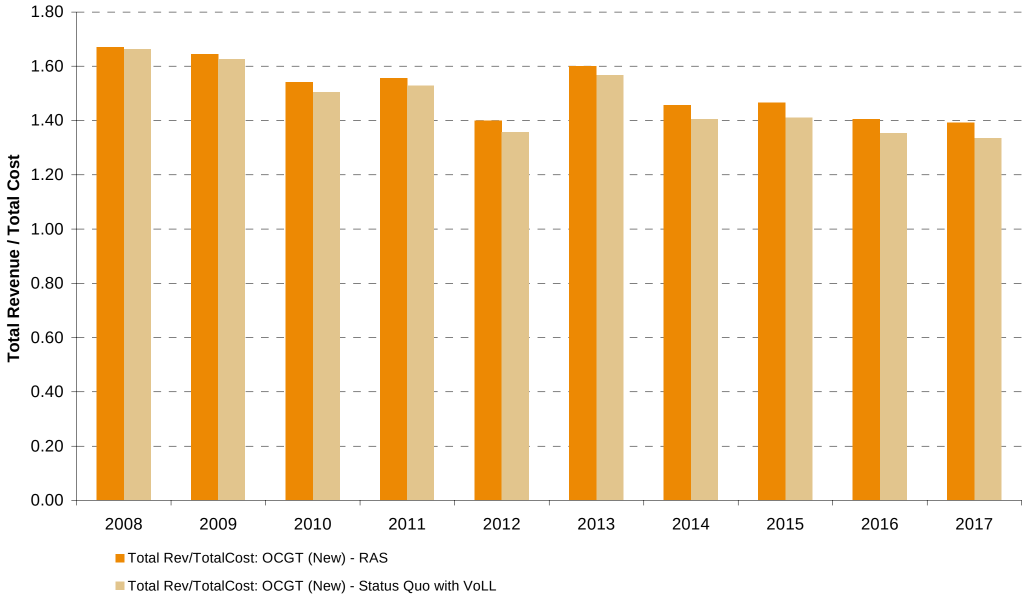
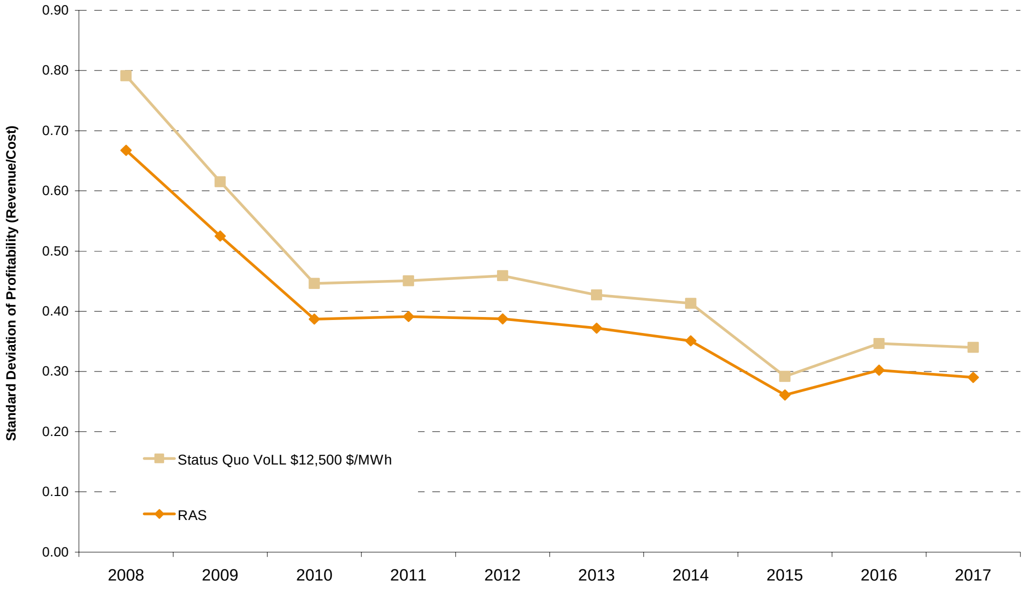


Figure 29: RAS: Comparison of Standard Deviation of Profitability to Status Quo



A.6.2 Option C: Standing Reserve

Figure 30 shows the amount of centrally contracted reserve generation modelled in the standing reserve option. This corresponds to the difference between the new OCGT capacity that is supported by the status quo VoLL $12,500/MWh and status quo VoLL $10,000/MWh cases. The standby reserve generators are offered into the market at VoLL ($10,000/MWh). The comparison of profitability performances is shown in Figure 31 and Figure 32. Although the standby reserve option yields a lower profitability, the standard deviation or variability is, as would be expected is lower.

Figure 30: Centrally Contracted Standing Reserve Generation

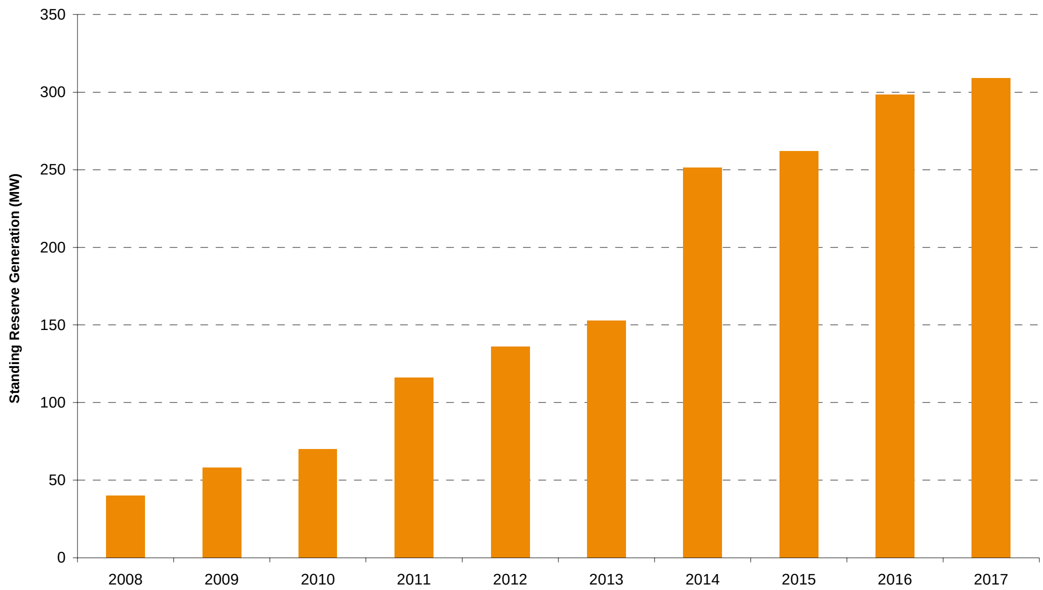


Figure 31: Standing Reserve: Profitability Comparison to Status Quo Sensitivity

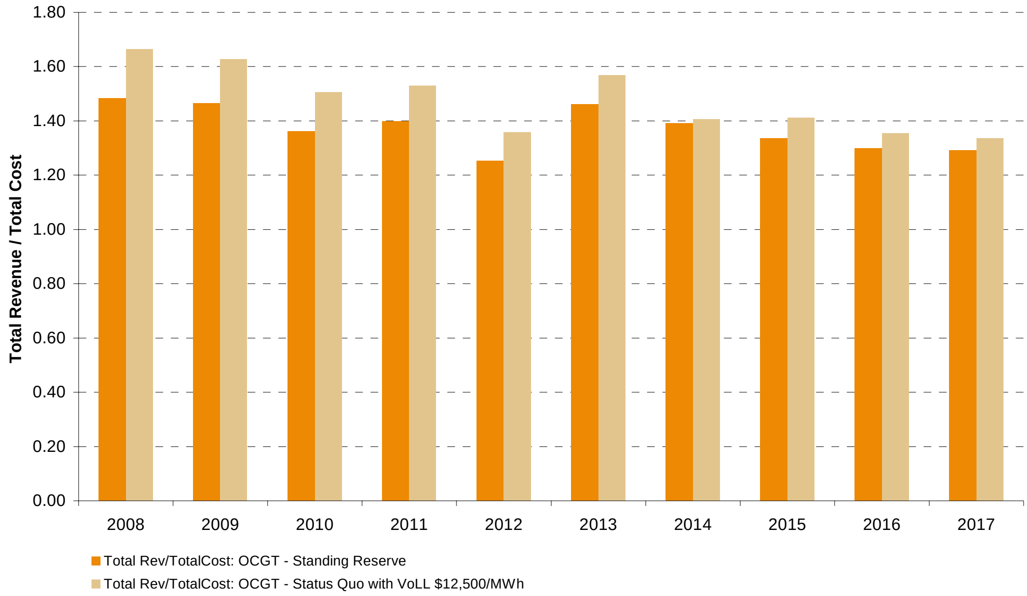
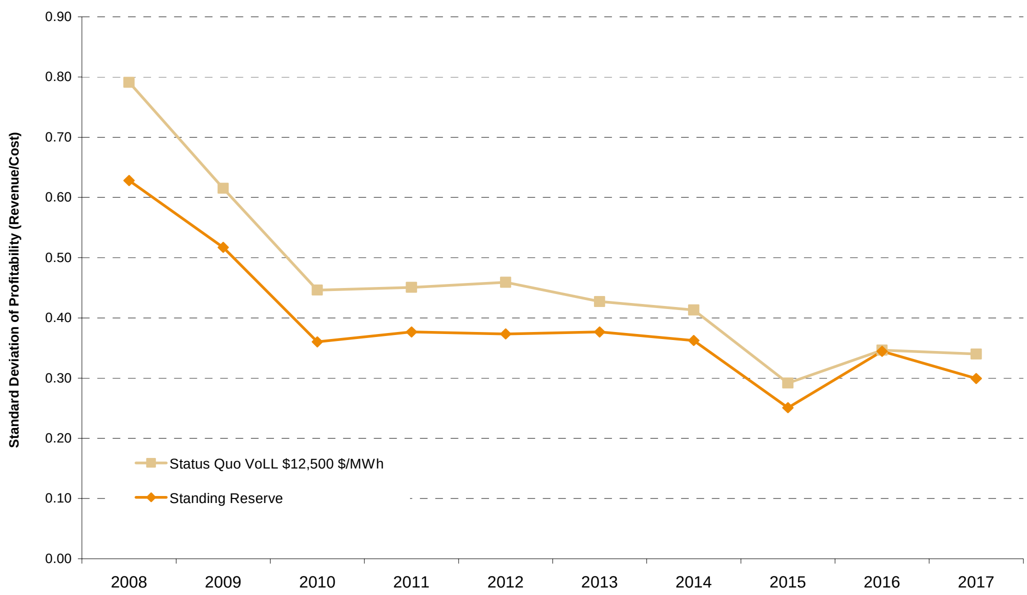


Figure 32: Standing Reserve: Standard Deviation of Profitability Comparison to Status Quo Sensitivity



A.6.3 Option D: Financial Reliability Options

In the approach that uses “Reliability Options”, a payment of $71,000/MW/year, equivalent to the capital costs of new OCGT entry, is assumed to be the option fee for the Reliability Option contract. In line with the design, VoLL is lowered to $3000/MWh.

Figure 33 shows the profitability over the period from 2008 to 2017.

Figure 33: Reliability Options: Profitability Comparison to Status Quo Sensitivity

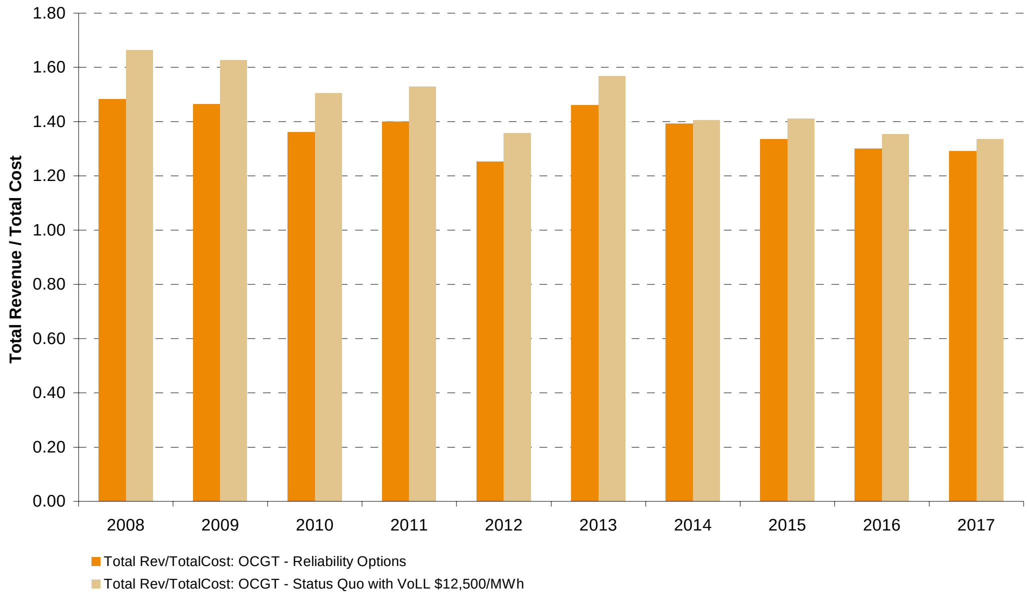
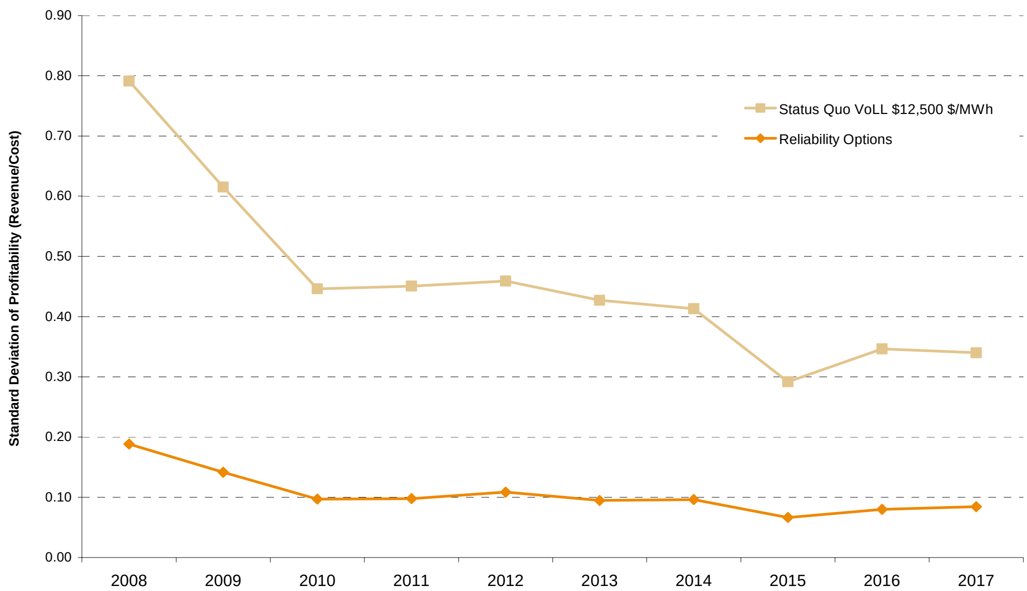


Figure 34 shows that there is a significantly lower standard deviation of profitability in Option D compared to the status quo.

Figure 34: Reliability Options: Standard Deviation of Profitability: Comparison to Status Quo Sensitivity



A.6.4 Average Cost Faced by the Customers

Improved reliability requires an increase in the level of redundancy in system capacity, and therefore additional costs to be borne by consumers. The payment mechanism and also the level of payment will depend on the choice of reliability instrument.

For instance, an increase in VoLL will reflect the additional investment through energy prices, whereas a RAS (Option B) will recover the investment costs through the ancillary services market in much the same way as generators are currently paid for frequency control services. Options C and D would diverge away from the current markets for energy and ancillary services, and would involve non-market based mechanisms or a substantially different market structure. In order to facilitate like-for-like analysis, we have adopted an approach whereby:

- The options are designed so that they all deliver approximately the same level of reliability;
- We compare the investment cost across these options and calculate the relative costs with respect to the status quo $10,000/MWh scenario; and
- We calculate the total costs across all load in the NEM to form a common basis of comparison relative to the status quo (VoLL $10,000/MWh) scenario. In other words, we calculate the *average increase* in energy equivalent costs for all the scenarios relative to the current market design and VoLL setting.

Figure 35 shows a comparison of the costs across all load MWh that range between 8c/MWh and 14c/MWh on average for all load across the scenarios. These results should be interpreted in the light of the following points:

- The cost for the status quo design with VoLL at $12,500/MWh is the highest because it reflects not only the investment costs in peaking OCGTs that are included in other options, but it also shows the impact of changes in bidding behaviour that might be induced by an increased VoLL;[8]
- The non-market standing reserve option yields the lowest cost because it has marginally lower peaking investment compared to other options; and
- All other options in our assumption have the same investment profile and also identical demand level – therefore the total investment cost for the peaking investment across the load MWh does not change.

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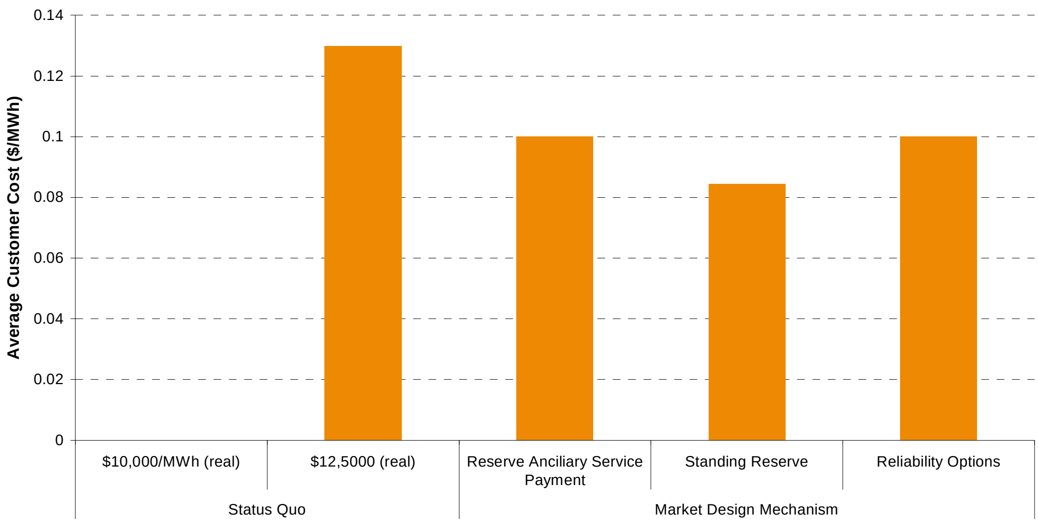
8 However, as we have noted before, the NEM price outcomes can vary depending on the bidding assumptions and minimum level of return expected by investors. As Figure 25 demonstrates, prices may also *drop* with an increase in VoLL if competition is enhanced by entry in the peaking or base load segments. Under such circumstances, the average cost of reserve may be lower than 14 cents/MWh and may in fact be lower than all other options if the benefit from energy dispatch compensates substantially for the additional investment.

It is important to bear in mind that the “raw” customer costs presented here form only part of the overall picture. Of additional interest is how robust each of the options is to external influences and policies that may (inadvertently) create uncertainty in the minds of investors or otherwise distort prices. These factors include:

- The certainty of revenue streams that will have an impact on discount rates (either directly or indirectly through risk management policies) applied by investors. A measure of the certainty of revenue is presented in the analysis of standard deviation of revenue in earlier sections;
- Whether the changes will induce more longer term contracting, an issue that has been identified by the Panel as a significant issue, in the body of the report;
- The relative shift in responsibility and accountability for decision making across the options;
- VoLL is quoted in real terms;
- Transaction costs; and
- Transition costs.

Figure 35: Average Cost to Customers of Capacity Reserve Provision



Note: Customer cost calculated relative to the status quo $10,000/MWh scenario, and spread across all NEM load MWh.