A report on the implications of the RET and generation over-supply

Sydney +612 8006 8107 Adelaide +618 8331 1358 Brisbane +617 3263 7612

DISCLAIMER

This report has been prepared for the Energy Supply Association of Australia to assist in an examination of the effects of and interactions between over-supply of generation and the Renewable Energy Target in the National Electricity Market and the WA Wholesale Electricity Market. Aspects of the quantitative analysis relies on data and forecasts prepared by others and Oakley Greenwood disclaims liability for the accuracy of those data and forecasts. The work also examined scenarios involving shutdown of generation plant – these are major commercial decisions and our analysis of these matters was agreed with esaa and hypothetical. Oakley Greenwood disclaims all liability in this repsect inf the design of the cases studied.

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1. Executive summary

Oakley Greenwood Pty Ltd was engaged by the Energy Supply Association of Australia (esaa) to examine the implications of the current surplus or over-supply of generating capacity and interactions with the Large Scale Renewable Energy Target (LRET) in the National Electricity Market (NEM) and the Western Australian Electricity Market (WEM).

Key interactions analysed were the rate of demand growth, the level of renewable energy investment and targets, the role of gas in the electricity markets and mechanisms for reduction in thermal generating capacity assumed as the rational response of generators faced with low prices due to over-supply. The mechanism, timing and orderliness of responses of market participants, including direct and indirect withdrawal, were considered, in particular the risks associated with “disorderly” withdrawal of capacity and the associated policy implications. Finally, the work also considered whether, in light of those risks, external policy intervention should be recommended and what form it could take. The work was undertaken in two phases. The first examined supply and demand and options for withdrawal of capacity in response to over- supply to 2030. The second phase looked at the implications for the LRET for a subset of the cases in the first phase, through to 2040.

The consequential impacts on wholesale market prices, reliability of supply, renewable entry and the price of renewable certificates were examined.

The analysis assumed no carbon price from July 2015. Earlier removal of the carbon price would not materially affect the results. Following discussion with esaa the analysis assumed a revenue stream equivalent to that currently delivered from the sale of renewable energy certificates (RECs) continued to 2040. The revenue could come from extension of the LRET or from decisions by businesses to underwrite renewable investment.

In the first instance quantitative economic market modelling was used to examine the range of possible market outcomes. Cases examined included situations with commercially unsustainable outcomes that demonstrate the depth of the problem(s).

For the NEM, analysis:

- Confirmed a generally held view that commercial outcomes would be unsustainable if all thermal generating plant remains in service, especially coal plant operating in traditional base load mode shutting down only for maintenance;
- Confirmed also that the LRET plays a very significant role. The current target grows faster than forecasts of demand taking market share from incumbent gas and coal. In the absence of a price on carbon, the REC penalty price will cap returns to renewable facilities, significantly reducing the level of economic investment in new capacity. A shortfall in the order of 50 per cent of the LRET may emerge as a result;
- Demonstrated that economic withdrawal of coal plant through a combination of shutdown and seasonal cycling is likely. The amount of withdrawal is significantly affected by the level of demand growth and assumptions about whether LRET investment will be limited by economic returns linked to the penalty price. The majority of withdrawal is likely to be black coal but brown coal will be affected as well given that the strongest development of renewable plant is expected to be in regions with brown coal. Export capacity from brown coal regions will be a factor in the balance of response between brown and black coal;

- Demonstrated that gas use for power generation would fall to low levels – a low level of take-or-pay was assumed for discretionary gas plants after the first few years on the basis that contract volumes would be on-sold, but some volume would be retained to be able to back retail electricity hedges or internal gen-tailer positions. Gas volumes in the studies consistently sat at the minimum assumed until around 2025 or beyond;
- Highlighted that wholesale electricity prices would remain low for a number of years: set by coal plant for extended periods. Annual average price will be somewhat insulated from the expected rising gas price until demand rises and or thermal plant has withdrawn, to the point where gas is (again) at the margin, but then "kick" up sharply as the gas price may have risen significantly by that time; and
- An "orderly" withdrawal of coal plant through progressive shutdown and cycling in response to the market outcomes will see a relatively flat and low wholesale price and little risk of supply shortfall. Possible sudden, unheralded, withdrawal would result in a significant jump in both wholesale price and possibly lead to supply shortfall – a "disorderly withdrawal". For example if competitors choose to avoid being first, or the next, to move, but then one of the more seriously affected participants chooses to make a significant reduction. The expected strong demand for gas in NSW may see the assumed take or pay quantities also act as a cap on available fuel until the market reverses and additional gas for power generation is available. Withdrawal of gas fired generation will have limited effect as dispatch is expected to be reduced to minimum levels in any event but would change the risks that high prices and low capacity reserves could affect market outcomes in unexpected circumstances.

For the WA WEM:

- The existence of long(er) term physical contracts and the operation of the Reserve Capacity Mechanism are likely to insulate the WEM from similar outcomes for generation expected in the NEM. However, this occurs as a result of the risks associated with over supply being carried more on the customer base than in the NEM;
- Together with the Reserve Capacity Mechanism, higher gas prices should allow the WEM to support its pro-rata share of the existing LRET although this may be borderline under low demand growth conditions;

  However, the Minister of Energy has recently announced a major review of the market design including around the Reserve Capacity Mechanism. If the review results in a change to the design that increases exposure of generators to over-supply due to falling demand then clearly the position in Western Australia may shift closer to that of the NEM, but this will also depend on the design of an transition arrangements.

Implications for over-supply

A key strategic question for policy makers is how likely is it that market responses will be as gradual or orderly as that developed in the modelling. Put another way, what is the risk of disorderly withdrawal and whether pre-emptive action, or at least planning for it, is warranted?

It could be argued that the most likely form of withdrawal will be progressive decrease in maintenance leading to an increase in forced outages. Although there would be a lag time, this would be reversible if needed. However, the work indicated that the while gradual reduction in effective capacity from increasing forced outages would mitigate the adverse commercial outcomes, unsustainably low prices would still occur.

The analysis showed that the annual dispatch of gas fired plant would be low and in the analysis was held up by the take or pay input assumption agreed at project start. Withdrawal of gas fired plant similar to that seen in Europe would be an economically rational response. However, this would have limited effect on the profitability of coal and thus withdrawal of coal plant. The reason for this is that the reduced operation of gas plant is concentrated in the higher load periods in any event and coal is still subjected to low shoulder and off peak prices.

The study also highlighted a difference between the NEM and WA WEM. Although there is over-supply in both markets, the WA WEM market design places more of the consequence on the retail side of the market. In addition the re-merger of Verve and Synergy will bring many of the significant decisions that are needed to produce an orderly withdrawal into the one organisation – the re- merge was completed during the course of the work.

The final section of the report discusses a number of barriers to exit, highlighting the high cost of full shutdown and the incentive to "hang on" and avoid first mover disadvantage but in the process increase the risk of "dis-orderly" withdrawal.

Implications for the RET

The analysis showed that with low and falling electricity demand and no price on carbon economic investment in renewable generation technologies will fall well short of the LRET. In the low demand growth scenario we worked with the shortfall was as high as 50 per cent.

This position will come about because reduced electricity demand and increasing LRET requirement is driving wholseale electricity price down to the point where gas is at minimum feasible levels and coal plant is withdrawing, either shutting down, mothballing or moving to seasonal cycling mode. In the short to medium term coal is therefore the "swing" fuel, with plant that has not closed available to return to service when prices recover. Until all coal plant that has not been closed returns to full service, wholesale prices will remain at levels that provide remaining coal plant with just sufficient revenue to justify operation. This will give a relatively flat price below the level that will support significant renewable investment that is dependent on a falling REC price (noting the that penalty price in the LRET scheme is not indexed).

Eventually, assuming demand rises at some point and after all coal that is available to return is back to full operation, price will lift. and this will eventually support new investment. The lift in price may occur as early as shortly after 2020 or be delayed until the 2030s depending on the level of demand and the decisions of generators about whether to close or not.

One consequence of the possible prolonged nature of the over-supply is that as a number of renewable technologies are under intensive research and development at present, the nature of renewable technology that then enters when price does lift may be quite different depending on the timing.

2. Introduction

Oakley Greenwood Pty Ltd was engaged by the Energy Supply Association of Australia (esaa) to assist the Association examine the implications of a current surplus or over-supply of generating capacity in the National Electricity Market (NEM) and the Western Australian Electricity Market (WA WEM) and the Large Scale Renewable Energy Target (LRET).

The brief was initially focussed on over-supply (phase 1), but was refined during the course of the work in light of initial results and feedback from esaa and members, especially in respect of potential responses to over-supply. In light of the strong interaction with the LRET a second phase (phase 2) was added to the work to more closely report on the interaction between LRET and over-supply. The analysis in phase 1 ran to 2030 and in phase 2 to 2040.

3. Approach

We approached the over-supply issues in phase 1 in four stages involving a combination of strategic assessment and quantitative analysis liaising with esaa secretariat staff and a project team representing members of the Association. The stages were:

- Analysis of the current supply-demand situation including:
  - future electricity demand considering low and medium growth rates prepared by the Australian Energy Market Operator (AEMO) for the NEM and the Independent Market Operator (IMO) in respect of the WA WEM;
  - the outlook for external policy settings including the LRET; and
  - likely gas contracting timing and strategies;
- Potential responses to economic incentives and commercial strategies;
- Orderly and disorderly responses to the incentives for entry, exit, seasonal cycling and cold storage of generating plant; and
- Policy implications of observations.

3.1. Analysis of current supply-demand

3.1.1. NEM

To establish the context we examined the prevailing supply-demand balance. Price around the cost of a new entrant is an indicator of a market where supply and demand are in balance.[1] Over the last two years wholesale Spot Prices in New South Wales, Victoria and Tasmania have been consistently below any measure of the long run cost of new entrant (after allowance for a carbon price – see Figure 1. With the significant exceptions of a period in autumn 2013 in Queensland and Winter/Spring 2013 in South Australia, prices in these regions have also been below new entrant costs.[2] In July 2012 prices rose in line with the introduction of a price on carbon and average carbon emission factor just under 1t/MWh.

1 Current new entrant gas based costs are of the order of \$60-\$75/MWh before accounting for a price on carbon depending on assumptions around capital cost, fuel cost and risk premium

2 After the date of initial analysis, prices were also elevated over summer 2013/14 due to extreme weather in southern regions.

The low out turn prices in the NEM over this period are therefore consistent with an over-supplied market signalling excess capacity.

Figure 1 Historical 30 day moving average Spot Price by NEM region

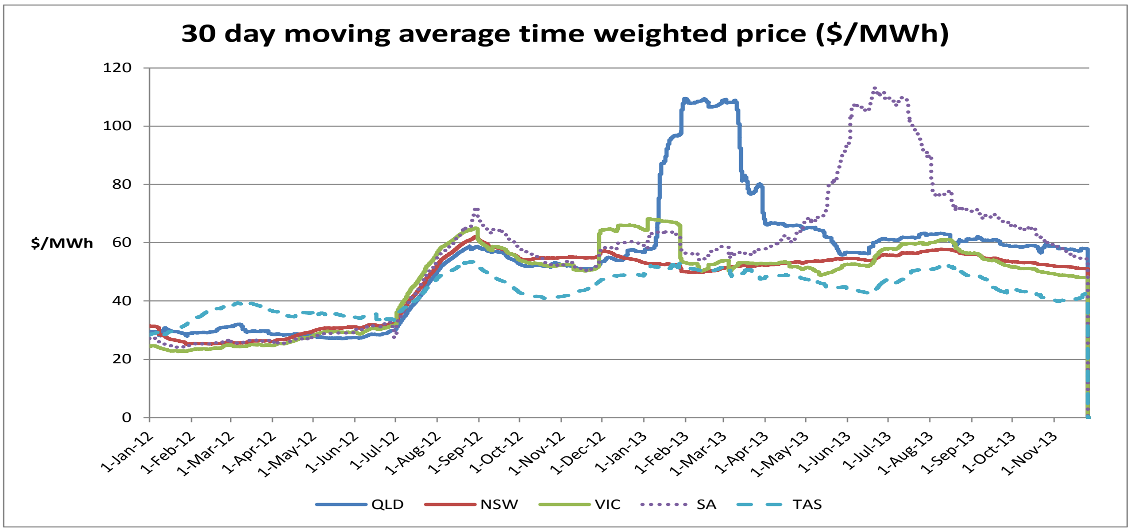
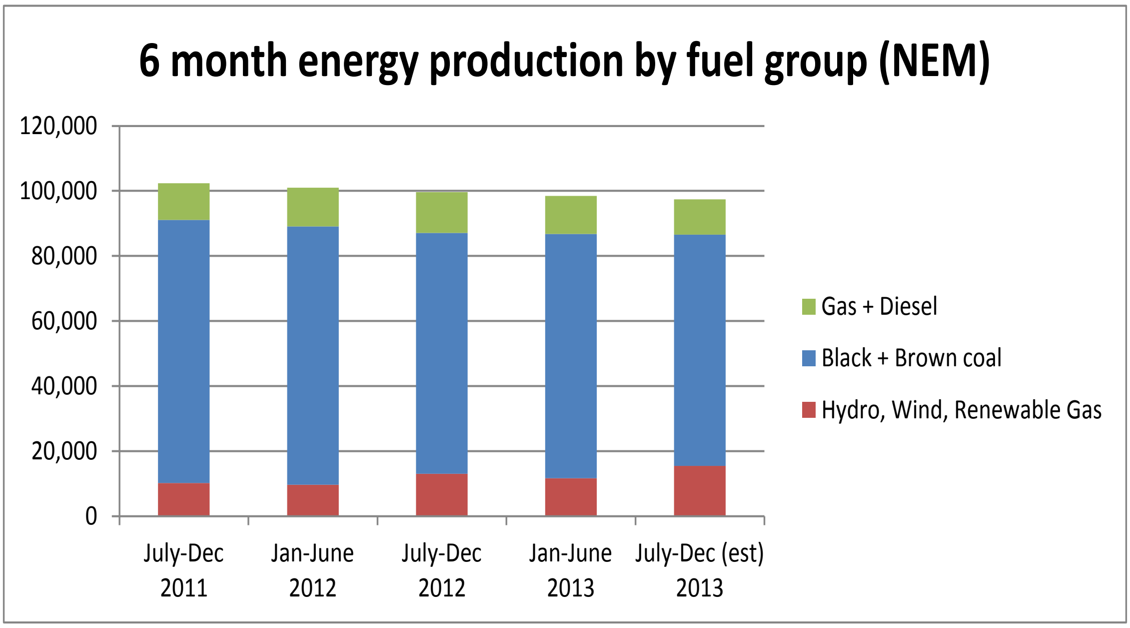


Figure 2 summarises energy production in the NEM by major fuel group over a similar period. Key points to note in Figure 2 are:

- Demand has fallen each 6 month period;
- Hydro and wind output has increased substantially, each in the order of 50%;
- Gas fired generation has remained essentially flat; and
- Total coal fired generation has also fallen from approximately 80,000GWh per 6 months to the low 70,000GWh, also a fall of approximately 10%, however, brown coal has fallen around twice as much as black coal in percentage terms.

Figure 2 Recent historical energy production by fuel group



Over the two years there has been some withdrawal of the capacity of coal plant through a combination of seasonal cycling (Northern Power Station in South Australia) and extended unit outages in Victoria (Yallourn), Tarong in Queensland and recently Wallerawang in NSW. Brown coal output has fallen further in percentage terms than black coal contrary to generally accepted understanding of the relative incremental costs (including accounting for the effect of carbon price). This result suggests factors other than incremental costs are influencing decisions in this regard and highlighting the need for caution in any examination of which stations may be candidates to reduce further in the future.

At the same time gas fired generation has held relatively stable: consistent with external factors related to fuel supply contracts and gas generation policies supporting the level of production from gas generators.

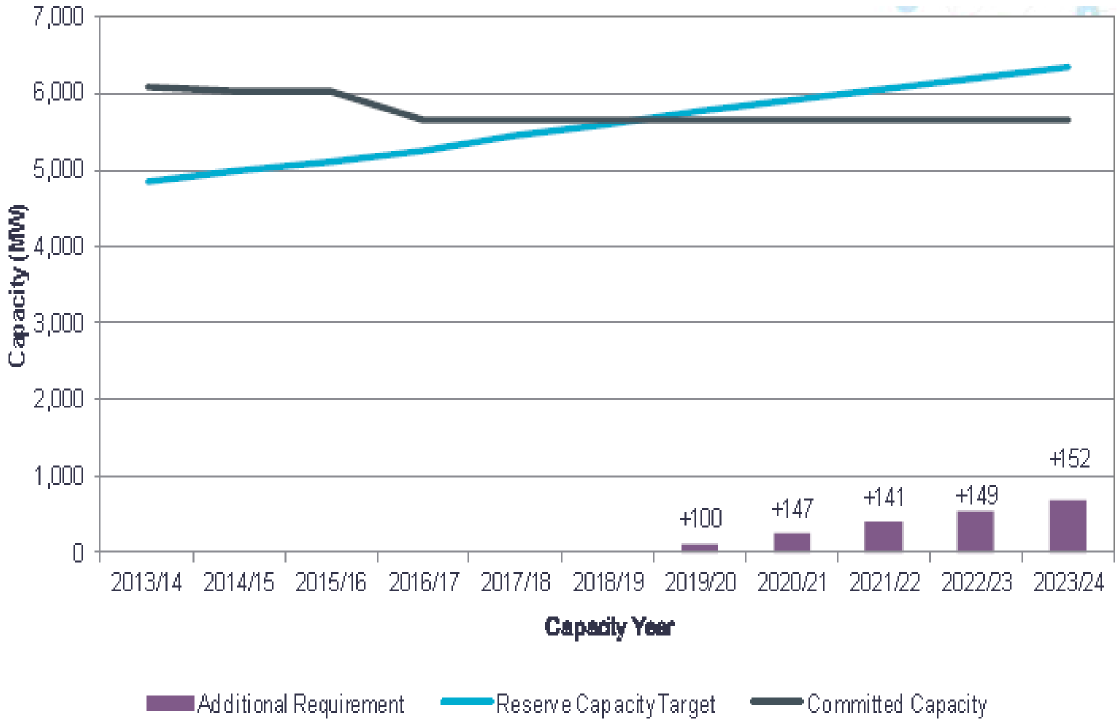
The increase in hydro generation appears to be above the long term sustainable level of the resources and may therefore not continue at the recent levels.

In summary, this high level overview further supports the view of over-supply and that multiple factors are influencing decisions about availability and generation levels. In particular, that the (NEM) market and non-market forces are present. Accordingly, a strategic approach to analysis of future outcomes and risks is warranted.

3.1.2. WA WEM

In the WA WEM the IMO Statement of Opportunity describes a significant capacity overhang with installed capacity well in excess of the minimum required level to meet the reserve requirement in the WEM, see Figure 3, which appears in the IMO 2013 Statement of Opportunity and assumes the possible retirement of an aging coal station at Kwinana.

Figure 3 WA WEM capacity balance (Kwinana C retirement)



Source: IMO 2013 Statement of Opportunities

3.1.3. Methodology

To investigate the future balance between demand and supply (including technology mix) we employed an economic market investment and dispatch model. Economic modelling of electricity systems is influenced by inputs to the analysis. In this current work, judgements about inputs were particularly important as a number of existing sources of generation will be competing for limited dispatch opportunity and very limited new capacity is expected to be required for a number of years in either market. This situation is more complex than when the markets are in balance or expanding and the question then is which technology should be built and what the resultant market prices will be.

Phase 1 was studied to 2030 with low and medium demand growth rates from AEMO and IMO forecasts issued in 2013 and assuming the existing LRET schedule is met in full and also if LRET investment is constrained to only economic investment after accounting for energy market and renewable certificate revenue. Phase 2 analysis ran to 2040. For the purposes of the study it was agreed with esaa that we should assume a revenue stream equivalent to the existing REC revenue will continue beyond 2030. This was done to avoid the need to postulate how market participants would respond as the time the end of the current regime is due to finish and allowed the analysis to identify options for delayed investment in renewable resources.

In the NEM, annual production from discretionary gas fired generation was constrained to a minimum of 25 per cent of its recent historical level. Gas generation associated with industrial processes such as within co-generation facilities was treated as non-discretionary and retained at its historical level. Open cycle gas turbine plant was not constrained and in practice produced very little energy. A similar approach was adopted for the WA WEM although there are more co-generation and plants where gas use is not dependent only on electricity requirements than in the NEM. The assumptions for each plant are presented in Appendix A.

The model covers generation participating in the wholesale markets. In the NEM small embedded generation and generation that is non-scheduled under the National Electricity Rules can contribute to meeting the LRET but is not explicitly represented in the market and hence is not in the model. For this reason the LRET requirement in the model is adjusted to consider only the portion of the total LRET requirement that is also directly available to meet the AEMO forecast of "operational demand" and IMO forecasts for the WA WEM.[3] The LRET requirement to be met within the market and the model is increased by estimates of GreenPower Sales and for desalination plants in each state as generation for each of these requirements may not be account as contributing to the LRET – see Appendix A for further detail.

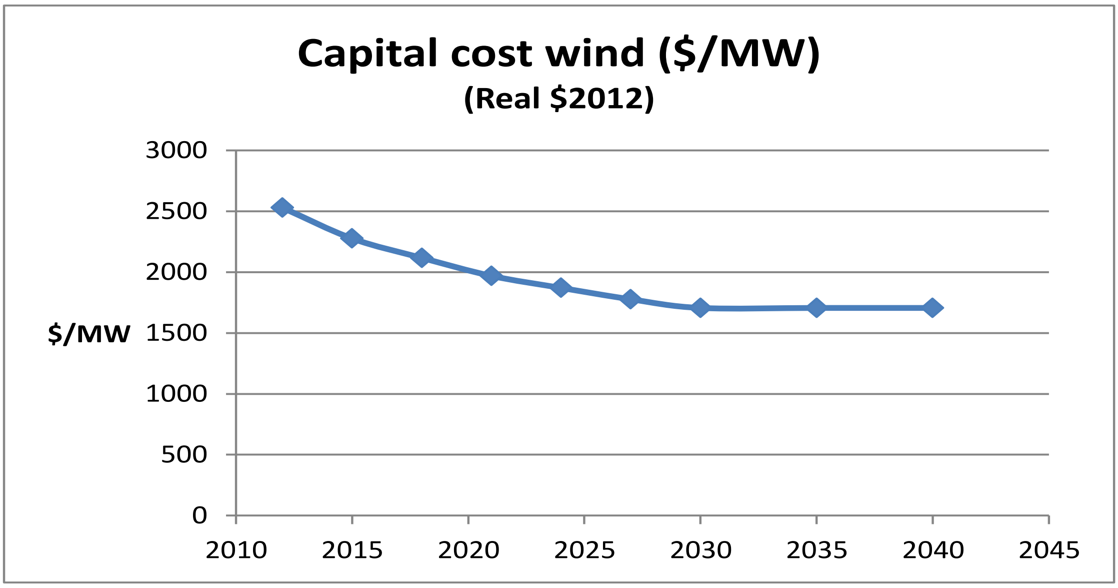
NEM Spot Prices presented are based on modelling of supply and demand including game-theoretic techniques to assess market behaviours. Observation of actual prices in the current market circumstances suggest that while price will be low based on fundamentals, it will be more sensitive than it has been historically to "outlier" events that either have very low probability (such as combinations of network outages) or are simply not modelled (such as open cut failures). The impact of this type of event can see annual price rise substantially in practice. Assessment of differences between price based on fundamental analysis of this type and observed price-demand relationships may be used in commercial analysis by businesses, but has not be applied in this policy oriented work

3 The concept of *operational demand* is explained in AEMO demand forecasting publications. See http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013

Where interconnector capability was a limiting factor the study assumed that capacity would be raised to the maximum that is currently available under favourable loading conditions. This is clearly an approximation and assumes that where lower limits currently apply they are due to secondary limitations or generation patterns that can be redressed at moderate cost, rather than primary limits that can only be increased with major investment. For the purposes of this work we did not attempt a cost/benefit analysis of interconnector upgrades. To the extent that this approximation over-estimates interconnector capability, we expect it will shift the balance between regions and types of coal plant that would be candidates for withdrawal, but it would not alter the broad conclusions of the study.

The dominant renewable technology available to meet the LRET schedule was wind. As the low market price and REC penalty price were limiting factors in the level of renewable generation plant that was economic, the capital cost of wind was a critical factor. We used information provided by the Bureau of Resources and Energy Economics (BREE) in its Australian Energy Technology Assessment (AETA) of 2012 as the basis for the capital cost of wind at $2,530/kW (the 2013 update of the AETA did not address wind capital cost). We applied an initial learning rate of 7% but assumed the capital cost would stabilise by 2030 (in real terms). The resultant capital cost over time is shown in Figure 4.

Figure 4 Capital cost of (onshore) wind



The impact of capital costs over the life of a project are of course dependent on assumptions about the level of debt funding, financial parameters, funding model, amortisation periods and exchange rates and thus may vary significantly. In the studies both the level of thermal plant withdrawal and level of investment in renewable technologies was affected. It was recognised that by the later years of the study other renewable technologies may be economic, depending on how costs for these technologies evolve. However, we did not investigate this possibility as the focus of this work was on the strategic interactions of over-supply and the RET as a policy instrument and for simplicity and ease of comparison between cases wind was modelled as the dominant available renewable technology.

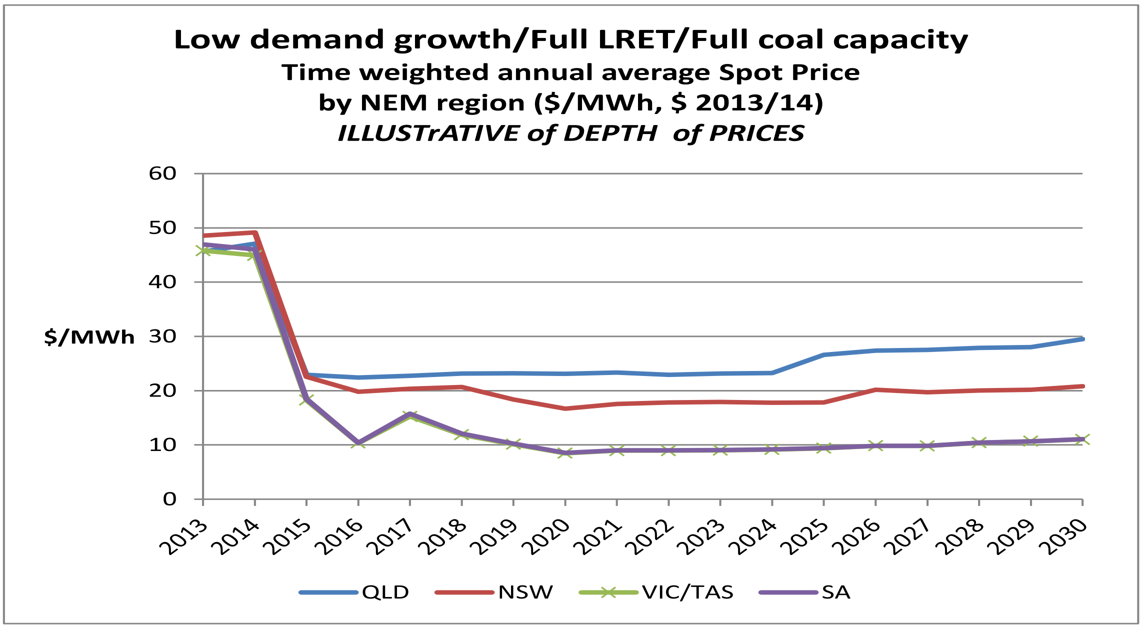
4. NEM

4.1. What if no-one reacts – how big is the "problem"?

Our first quantitative analysis assessed how low prices might move if no capacity withdraws from the market and the full LRET is met. This analysis gave impractically low prices and commercial outcomes in the NEM generation sector, as low as \$10/MWh up to \$20/MWh. This result is useful only to emphasise the high probability that withdrawal of capacity is needed – the results should not be regarded in any way as a forecast of outcomes that might ever eventuate.

Prices for Tasmania have been charted as the same as for Victoria. In practice Tasmanian prices may move above or below Victorian prices depending on hydrological conditions. However, recent policy and regulatory initiatives now benchmark market activity in Tasmania to a longer term Victorian price. We have assumed that for the purposes of this assessment the Victorian price will be a reasonable representation of medium term price in Tasmania.

Figure 5 Spot Prices - low demand growth, full LRET and full registered capacity



4.2. Assessing different types of response

In light of the initial results showing impractically low prices and in conjunction with the esaa we investigated the level of thermal generation that might be viable if the full LRET schedule was met and also the mix of viable thermal generation if only economically viable LRET investment occurred. Section 3.1.1 has described how some capacity has been withdrawn already – consistent with the uncommercial prices seen to date.

The level of viable thermal generation was found by comparing the Spot Market revenue against operating costs. Analysis of this response can only ever be approximate. Confidential case by case assessments would be made by the affected businesses before any significant decisions about withdrawal would be taken. We considered use of the Spot Market Revenue:Operating Cost ratio was fit for the purpose of the analysis and provided a strategic or order of magnitude view to allow assessment of whether the impact would be material.

We also note that the impact of withdrawal is likely to vary depending on which generator and in which region withdrawal is contemplated. As noted we would expect this would be a decision taken on a case by case basis and involve commercially confidential information. When the ratio of spot revenue to operating costs is 1.0, a generator will be covering operating costs, but making no contribution to capital return or payment of any debt. It is therefore a break-even operating position, which can only be improved if further thermal plant withdraws or other market changes occur that result in, higher, commercially viable prices.

We withdrew capacity from the model such that price rose to the point where ratio was above, rather than under, 1.0. Allowing the ratio to sit above 1.0 provides some safety margin and some return towards capital and it also recognises that per unit input costs are likely to rise as volume falls, for example the cost of fuel and fuel handling equipment.

For the cases which examined how far the level of renewable plant would be reduced if investment was capped by the revenue available from the energy market plus the sale of Large Generation Certificates (LGCs), we limited investment to the capacity that could be supported within the tax effective penalty price of the certificates. By design our analysis potentially over rather than under states the amount of renewable investment: for example we assumed that investment could continue during the 2020s and would not be affected by the current end date of the RET scheme in 2030. Withdrawing thermal plant until the ratio of spot revenue:operating cost is above 1.0 also increases the level of renewable plant that can be supported. This approach is clearly an approximation but we consider appropriate for the primary purpose of this work and does not affect the key conclusions.

The following sections summarise the results from our analysis – details of the input data or data sources and the results are provided in Appendix A. A discussion of the strategic conclusions follows in section 7.

4.3. Low demand growth, full LRET schedule met, economic thermal plant

Starting with the low demand growth forecast published by AEMO, renewable plant was constrained to follow the published LRET schedule requirements and thermal plant was withdrawn through a combination of seasonal cycling and progressive shutdown of generation.

An annual wholesale price around $30/MWh (in 2013-14 dollars) was shown to be needed to leave thermal generation with a ratio of Spot Market Revenue: Operating cost no lower than 1, this is a a breakeven position. No new investment should be expected to enter the market at this price. Notably the period before introduction of a price on carbon saw Spot Prices of this order – see Figure 2.

The operating cost ratios for gas plants using minimum take quantities of gas were often below 1, consistent with sunk cost for fuel within a take or pay arrangement. It also implies that retail contracts (or internal risk management arrangements) cover the differences. Another factor that may influence these decisions is that businesses with a portfolio of plant may also have the choice of mothballing some plant to reduce costs. The analysis did not extend to considering individual portfolios

The study required the withdrawal of thermal plant. For practical purposes it was necessary to withdraw particular generators in the model. The choice of which generators were withdrawn within a region may be contentious if reported, for this reason our report presents aggregated results only. Of particular interest is the withdrawal of both black and brown coal plant which was found to be necessary to increase the revenue:cost ratio to its minimum level.

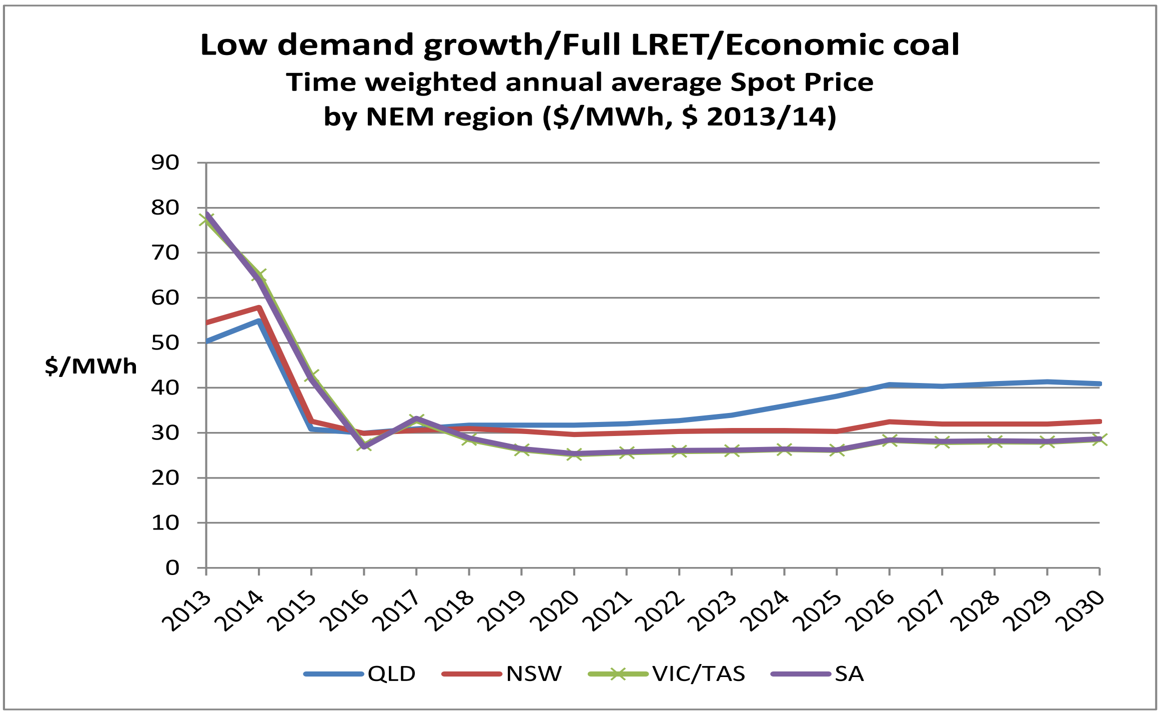
A simplistic assessment on the basis of incremental operating cost alone would suggest Victorian brown coal would be the last coal plant to be withdrawn, however this was not the case. This outcome can be understood by noting that brown coal is located in the regions with more severely depressed prices of Victoria/Tasmania and South Australia as seen in Figure 5 where brown coal plays a large part and these regions also have the majority of investment in response to the LRET.

Table 1 lists the amounts and means by which black and brown coal capacity was withdrawn in this case. We note again for emphasis that the particular combination of withdrawal shown here is likely to be one of a number of ways in which a similar effect could be achieved. Figure 6 charts the Spot Prices observed in this case.

Table 1 Low demand growth, full LRET, economic coal - capacity withdrawal (rounded) from registered

Fuel type	Seasonal withdrawal (cycling)	Capacity withdrawal (shutdown)
Black coal	-	2900 MW
Brown coal	1400 MW	250 MW

Figure 6 Spot prices - low demand growth, full LRET, coal withdrawn



The chart shows the beginning of a trend seen in subsequent cases where Victoria/Tasmania and South Australian prices are aligned and fall below the NSW and Queensland prices. This result indicates interconnector capacities north of Victoria and at times between NSW and Queensland are limiting, but the capacity between South Australia and Victoria is not as limiting (note we accounted the South Australia to Victoria capacity as including the increase for the planned Heywood upgrade).

Reliability was high in all regions with negligible unserved energy, consistent with surplus capacity.

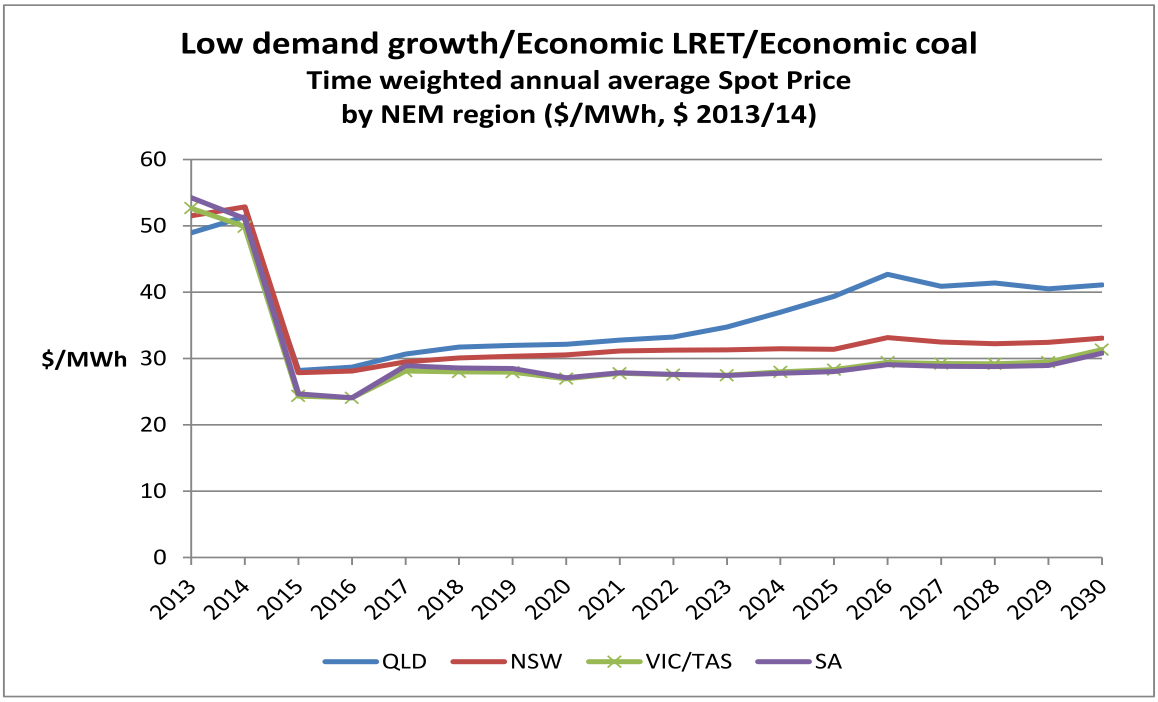
4.4. Low demand growth, economic LRET investment and thermal plant capacity

Using the AEMO low demand growth forecast (as requested by ESAA), the LRET investment schedule and thermal plant withdrawal were jointly adjusted until each was showing an economic position. The minimum generation of gas fired plant was unchanged from the cases where the full LRET schedule was met. The capacity withdrawal for this case is shown in Table 2. We found that after allowing for drawdown of the current store of banked certificates slightly less than 50% of the LRET was satisfied.[4] Figure 7 charts the Spot Prices in this case.

Table 2 Low growth, economic LRET, economic coal _capacity withdrawal (rounded) from registered

Fuel type	Seasonal withdrawal (cycling)	Capacity withdrawal (shutdown)
Black coal	-	1860 MW
Brown coal	1200 MW	250 MW

Figure 7 Spot Prices - Low demand growth, economic LRET, coal withdrawal



4 A accumulated bank of 33,000GWh was assumed to exist

Spot Prices in Victoria/Tasmania and South Australia were again aligned and below prices for Queensland and NSW. The Queensland price began to rise from about 2022 as the (relatively) higher rate of growth progressively drew increased import from NSW until new investment in CCGT plant entered in 2025.

Reliability was high in all regions with negligible unserved energy.

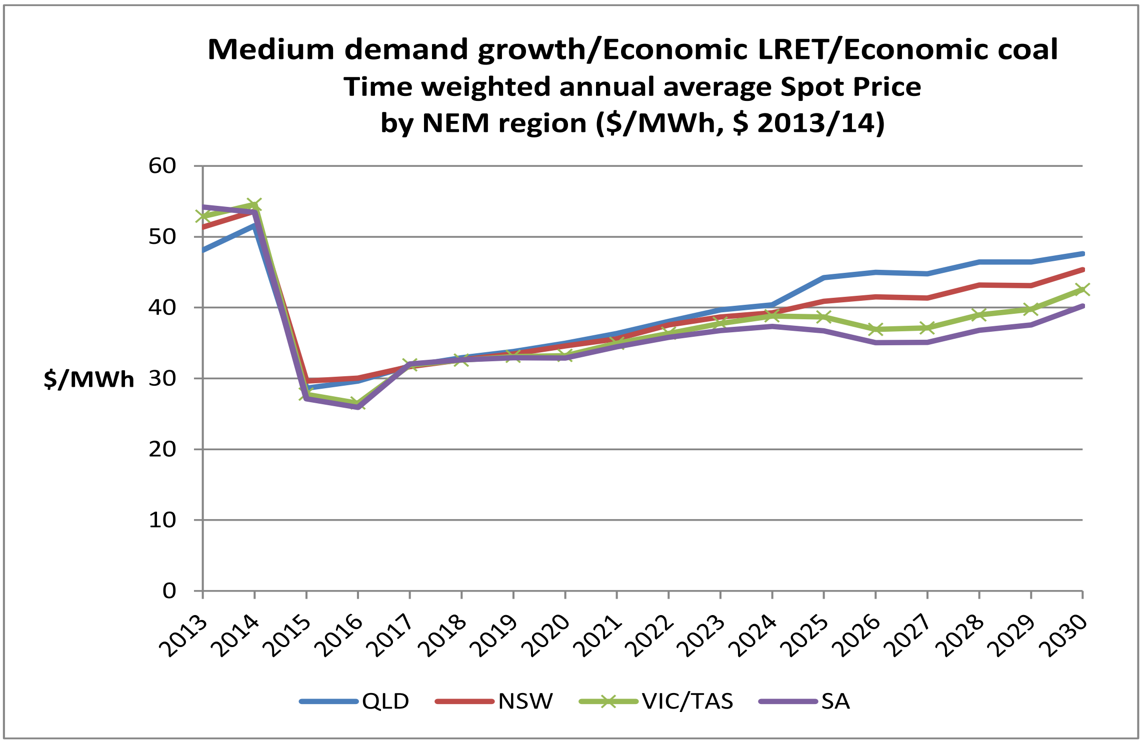
4.5. Medium demand growth, economic LRET investment and thermal plant capacity

Using the medium demand growth forecast from AEMO, the LRET investment schedule and thermal plant withdrawal were jointly adjusted until each was showing an economic position – see Table 3. Compared to the low demand case less black coal was withdrawn and seasonal cycling of brown coal was progressively wound back and the units returned to traditional baseload operation by the mid 2020s. Gas generation was again unchanged to ensure the minimum take or pay level was consumed. Figure 8 charts the Spot Price outcomes for this case.

Table 3 Medium demand growth, economic LRET, economic coal - capacity withdrawal (rounded) from registered

Fuel type	Seasonal withdrawal (cycling)	Capacity withdrawal (shutdown)
Black coal	-	1000 MW
Brown coal	1200 MW decreasing to 0 MW progressively over 10 years	-

Figure 8 Spot Prices - Medium demand growth, economic LRET, economic coal



Price outcomes were broadly aligned across the regions until around 2024. Victoria/Tasmania and South Australian price outcomes dip at the time brown coal units were moved back to traditional base load duty from seasonal cycling, suggesting scope for some adjustment of the timing of this change. The alignment of prices until into the 2020s also suggests less reliance on interconnector capability.

4.6. Low demand growth, full LRET schedule met, alternative disruptive withdrawal

In this case we investigated what the consequences would be if individual generators did not progressively withdraw but waited in vain for others to withdraw but then one generator initiated a major withdrawal (or a number withdrew simultaneously).

Given the expected strong demand for gas as LNG production ramps up and the public discussion of a tight gas supply position in some states, we assumed gas fired generators would have traded their entitlements to gas down to levels matching their expected requirement but could reverse this position in two years.

This set of circumstances delivers an indication of the severity of sudden withdrawal, it is not a forecast as the timing and strategies will be highly dependent on the individual position of the parties. The purpose of this case was to consider if the impact of this type of response would be material. **Error! Reference source not found.**Table 4 summarises the withdrawal of capacity in this case.

Table 4 Disorderly capacity withdrawal (rounded) from registered

Fuel type	Seasonal withdrawal (cycling)	Capacity withdrawal (shutdown)
Black coal	-	-
Brown coal	-	1500 MW

Figure 9 charts the sharp spike in price that resulted from the sudden, disorderly withdrawal with capped gas volumes. Figure 10 shows an equivalent spike in unserved energy to around 25 times the NEM reliability standard of 0.002 per cent. Clearly unserved energy would be less if some additional gas was available, however, the key observation is that the consequences of an event of this nature would be dramatic – albeit short lived.

Interestingly the Spot Price returns to low levels similar to other cases within two years. The reason for this is that once coal plant has withdrawn other coal plant becomes viable and no longer withdraws as the level of LRET increases and production from gas stations does not increase materially. Put another way the coal capacity withdrawn suddenly is replaced in the short term by increased loading (less offloading) on other coal plant in combination with a shift in the timing of the limited amount of available gas and load shedding. When higher amounts of gas become available it is not used, as by that time the LRET capacity has begun to increase and less other coal is withdrawn.

Figure 9 Spot Prices - Disorderly withdrawal of capacity

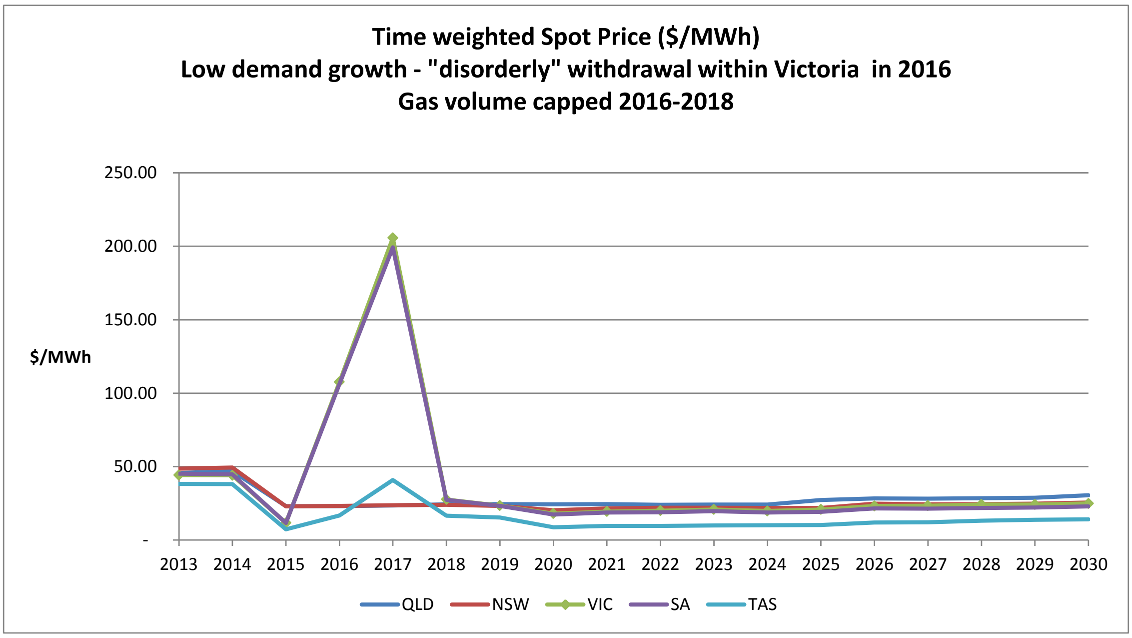
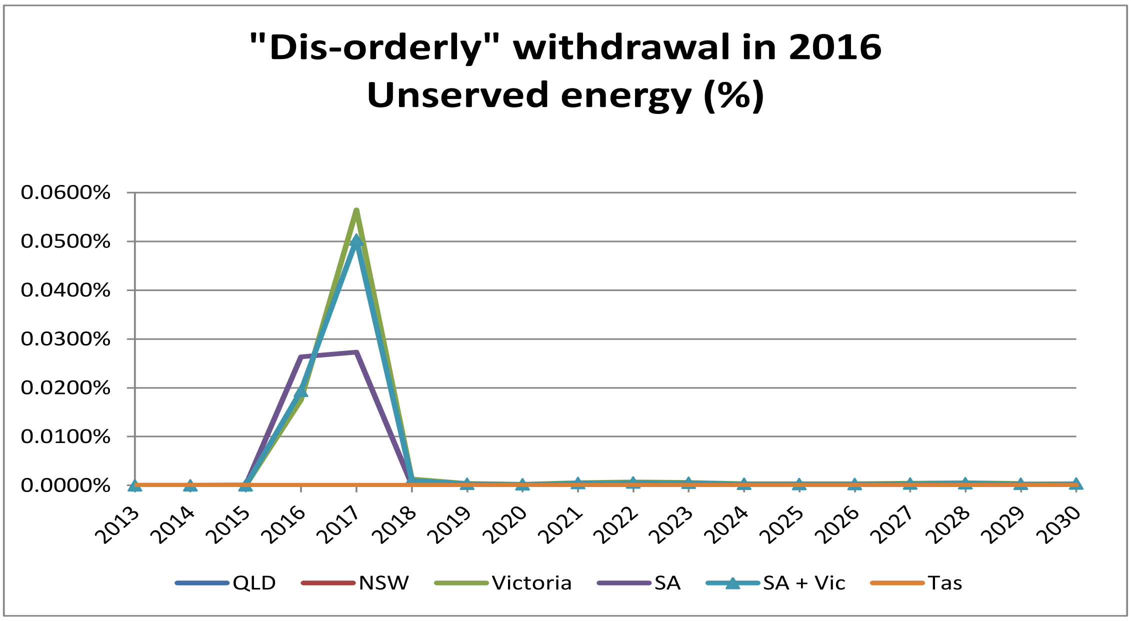


Figure 10 Unserved energy following disorderly withdrawal



4.7. Low demand growth, economic LRET schedule met, gas plant withdraws

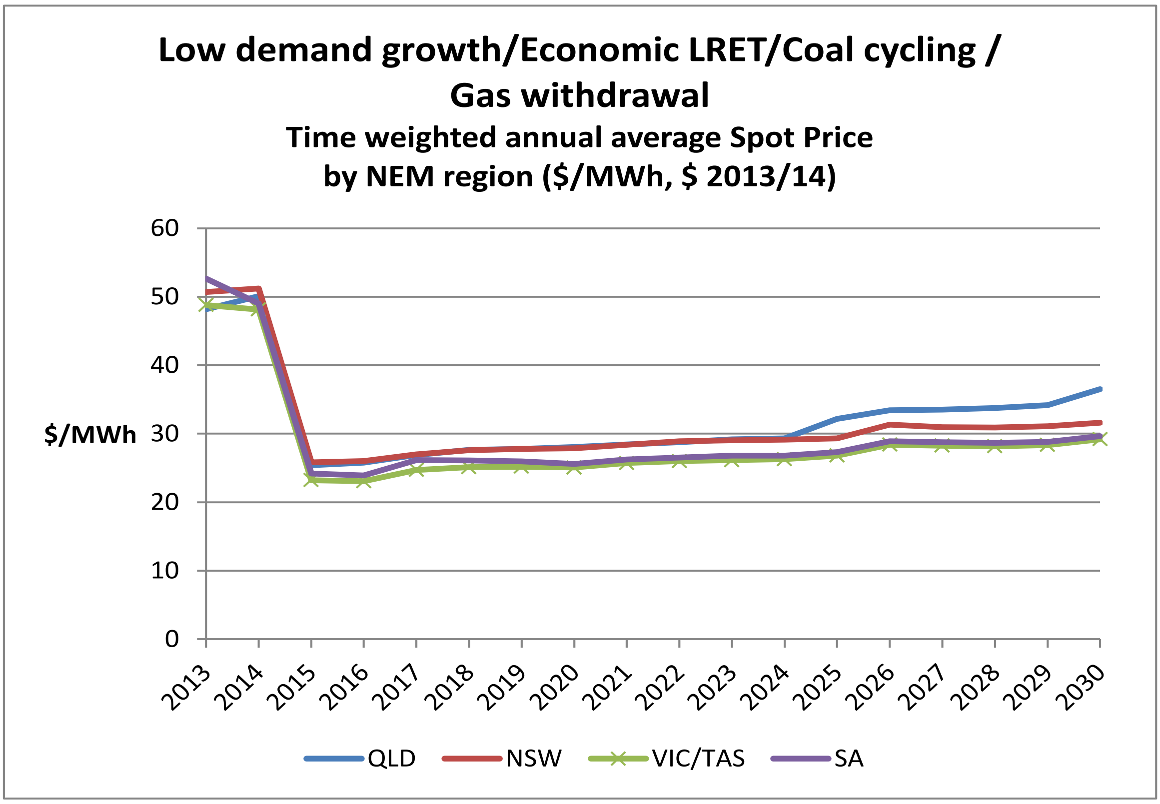
This case considered the situation that would emerge if gas fired plant withdraws. Gas fired plant is being withdrawn or left stranded in European power systems and this case examined whether withdrawal of gas fired plant as part of the suite of responses would make a material difference in the NEM. As the model was already scheduling the minimum take quantity of gas in peak and shoulder periods, we retained the off peak seasonal cycling of brown coal for this case – seeTable 5.

Table 5 Reduced gas capacity

Fuel type	Seasonal withdrawal (cycling)	Capacity withdrawal (shutdown)
Black coal	-	-
Brown coal	1200 MW	-
CCGT	-	1500 MW

Error! Reference source not found. Figure 11 charts the Spot Price outcomes for this case. Overall capacity withdrawal is lower than in other cases.

Figure 11 Spot Prices - Withdrawal of gas capacity



4.8. Low demand growth, full LRET schedule met, reduced coal maintenance

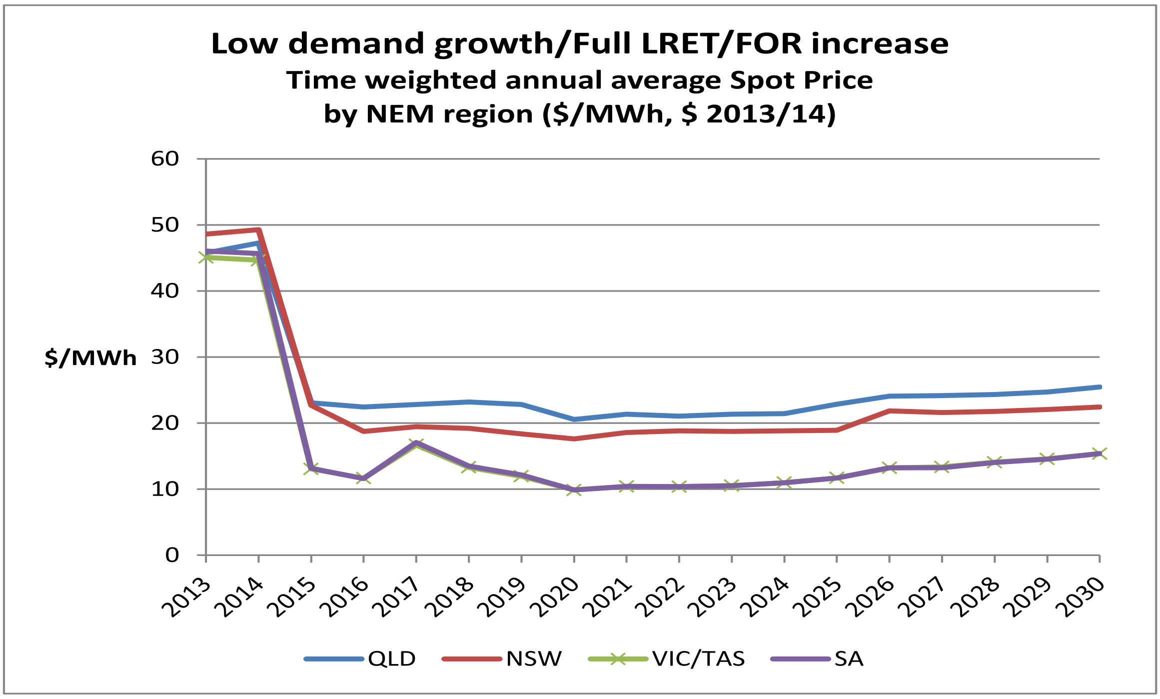
In circumstances where price is low, reduced maintenance effort would be a rational response but lead to lower overall availability of generation. Lower maintenance effort may see longer planned outages but no change in failure rate or less preventative maintenance and acceptance of a greater forced outage rate, or a combination of both.

This case examined the impact of doubling forced outage rate (FOR) across a significant proportion of the generation fleet -see Table 6. The result showed that increased FOR had some effect but was not sufficient on its own to replace withdrawal of whole units given the magnitude of over-supply and hence we did not study the effect of longer planned outages. Figure 12charts the Spot Price outcomes for this case – note the prices shown here are unsustainable, highlighting that withdrawal of capacity would also be likely, with the level of withdrawal dependent on the level and location of increase the maintenance outage rate.

Table 6 Increased forced outage rate allocation

Fuel type	Double FOR across	Seasonal withdrawal (cycling)	Capacity withdrawal (shutdown)
Black coal	7800 MW	-	-
Brown coal	4100 MW	-	-

Figure 12 Spot Prices - Increased forced outage rate



5. WA WEM

The WA WEM includes two distinct revenue streams to generators. The separation of revenue streams means that generators are less exposed to the commercial consequences of over-supply than in the NEM. The mechanisms are:

- The Reserve Capacity Mechanism (RCM): Under the RCM generators may receive a payment for capacity regardless of the level of dispatch. The payment may be direct from the IMO or indirect. The payment is indirect when it is bundled with a (physical) bilateral contract with a retailer. If a generator and retailer notify the IMO that they have entered into a relevant bilateral contract, the retailer is exempted from the obligation under the market rules to pay the capacity payment to the IMO and this is balanced by an equivalent reduction in the amount the IMO must pay to the relevant generators; and
- A three stage energy market comprising bilateral contracts, a day ahead short term energy market (STEM) and a balancing market. The net energy revenue and expense for participants in the energy markets is the net of the three stages. A critical feature of the operation of the STEM and balancing markets is that each has provisions relating to mitigating market power by requiring prices to be based on short run cost.

The bilateral contracts were modelled on earlier physical bilateral contracts providing for fixed and variable payments. To the extent the contracts, which are confidential, are of this form generators have limited exposure to over-supply regardless of whether it is due to over-investment, falling demand or increasing LRET requirement. The risk is therefore carried more on the retail side of the market compared to the NEM.

In principle generators relying on revenue from the capacity payment plus participation in the STEM and balancing markets only may face a bigger risk as these prices may be suppressed in surplus conditions. However, the demand on the SWIS is highly temperature sensitive with extremes due to air conditioning in summer matched only by the sensitivity of the demand in the South Australian NEM region. As a result there is a high percentage of open cycle gas fired peaking plant (approaching 40 per cent) that receives the capacity payment (or is assumed to within the fixed component of a bilateral contract) and is therefore relatively indifferent to the level of dispatch.

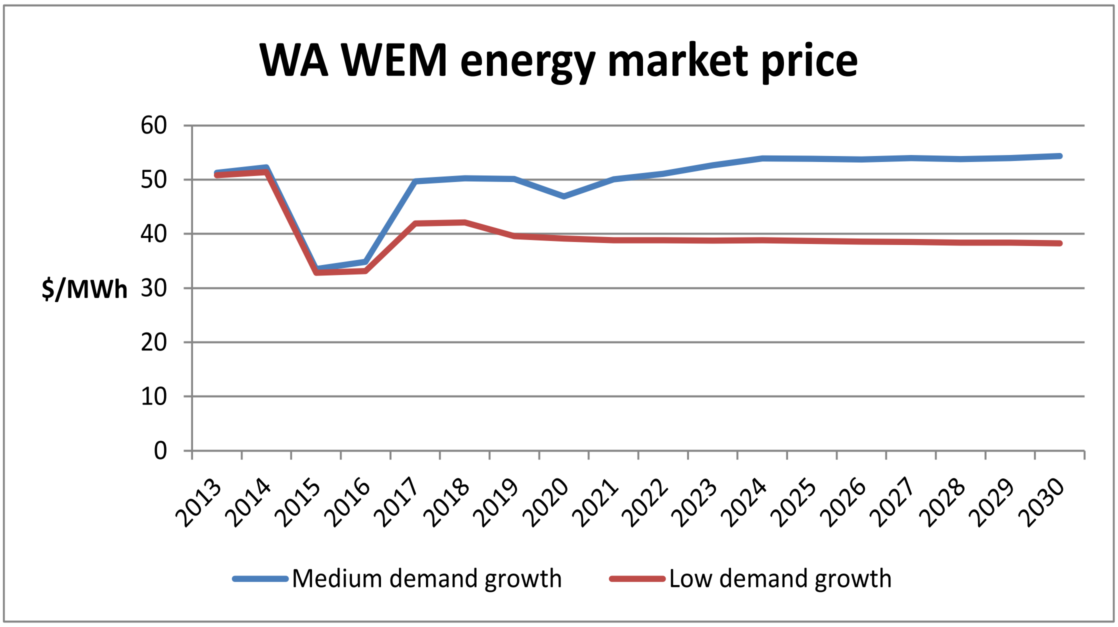
Until changes were made to the design of the balancing market in July 2012 the short term (overnight) operation of some coal units were being adversely impacted by the priority given to dispatch of wind generation. The changes to the market have redressed the overnight operating issues. In the longer term the commercial position of coal and discretionary CCGT/co-generation plant in the WEM is highly dependent on the nature of bilateral contracts, which can run for many years. Now that the dominant state owned generator and retailer have been re-merged to form Synergy, options for refurbishment or retirement of ageing assets are under single management and this presumably offers the opportunity for cost effective management of any concern about over supply – although the details are confidential. However, Muja A coal fired station is already operating in a peaking or seasonal cycling mode.

Overall, it is reasonable to assume that third party commercial players are also protected by bilateral contracts. However, external assessment is difficult as much of the necessary information is confidential.

It is likely that there will be sufficient revenue to allow the WA WEM to meet its pro-rata share of the LRET profile. We reach this conclusion considering the (current) payment from the RCM, price of RECs and likely energy price.

The RCM will pay up to approximately 20 per cent of the installed capacity (being an approximate capacity contribution of wind to peak in the SWIS but varying by location). $120,000/MW is a conservative allowance for the effective payment in the RCM, meaning a wind generator would receive $24,000/MW. At a capacity factor of 38 per cent this will deliver revenue of approximately $7/MWh from the RCM alone. By 2020 the penalty price under the LRET scheme will be equivalent to $76/MWh in 2013-14 dollars and higher before then, resulting in income of at least $83/MWh before considering the energy price. The gas price in the WA WEM is expected to be at least $6-7/GJ in the years leading up to 2020 and deliver an energy price no less than $50/MWh (Figure 13) giving total income in excess of $130/MWh in the medium demand growth which is adequate to fund investment in wind generation. Under low growth conditions the energy price is expected to be lower and net income for wind generation closer to break even but this will depend very much on decisions about retirement as well as the prevailing cost of renewable technology.

Figure 13 WA WEM energy price – excluding RCM



Note: the modeling forecast here assumed gas prices remain at historic low level until 2017 and then remain relatively flat in real terms. Earlier lift in price will see an earlier rise

5.1.1. Market design review

Just prior to the time of writing a major review of the WA WEM was initiated by the Minister of Energy. Background material released as part of the package of information about the review noted concern with the outcomes and the potential for significant change in design of the WA WEM. A change which shifted the allocation of risk more to generators, as it is in the NEM would clearly increase the potential for lower prices and have implications for the manner of withdrawal of capacity.

6. Implications for the large scale renewable energy target in the NEM

By design some of the cases were established to achieve the full LRET schedule. As noted earlier this outcome can only be supported if funds additional to Spot Market revenue and Large Generation Certificates (LGCs) are available.

To examine this effect more thoroughly ESAA requested a number of cases including two that were initially assessed in phase 1 be analysed out to 2040. These cases form phase 2 of the work. A description of the cases and results follow. Figure 14 and Figure 15 plot the installed capacity in the NEM (assuming the technology is wind) and the resultant NEM LRET energy assuming all other regions meet their pro rata share. A code for each case is also included in the following notes.

- Extending the low demand growth rate profile, following the full LRET schedule and reducing thermal generation until it sees spot revenue: operating cost above 1.0 (see curve LOW/FULL/ECON) This case is an extension of the case described in section 4.3 which examined the situation to 2030. In the period between 2030 and 2040 coal plant is progressively returned to service but is still not fully returned by 2040 and as a result spot prices remains flat in the low $30/MWh (real 2013/14) range. While the study conditions presumed all coal currently installed remains available to return to service and thus keeps spot price flat, it is doubtful that none of the plant would be closed if it was to be out of the market for this long (up to 20years). Accordingly this is a low estimate of the impact on spot price;
- Extending the low demand growth rate profile, balancing the economic level of LRET (assuming that a revenue stream equivalent to the existing REC payment continues in nominal terms) and seeking the economic level of coal plant (see curve LOW/ECON ECON). This case is an extension of the case in section 4.4. In this case <u>all</u> coal plant withdrawn in earlier years is able to return to service economically during the 2030s and by 2040 the price in Queensland has begun the lift but there is only small upward trend in other regions of the NEM;
- Extending the low demand growth rate profile, but freezing investment in renewable plant that requires support of the REC at current levels and retaining all available thermal plant in service (see curve LOW/FREEZE/FULL). This case is similar to the initial case examined in section 4.1. The resultant spot price is similarly very low initially (2014 - 2015) but rises to reach approximately $30/MWh by 2020. This result would suggest a short period of withdrawal and full operation of thermal plant from around 2020. This result is consistent with current market conditions and the actions of existing participants where withdrawal is occurring. It is also plausible that the majority of plant withdrawn at present could return in this period.
- We also tested the situation with medium growth rate with economic level of LRET and economic level of thermal plant –an extension of the case examined in section 4.5 where all withdrawn thermal plant had returned to service by 2030 and spot prices were of the order of $40/MWh (real 2013/14) (see curve MEDIUM/ECON/ECON). Renewable investment was still well short of the LRET schedule by 2030. By 2040, however we observed that prices had risen to in the order of $60/MWh by 2035 and $70/MWh by 2040 as new thermal investment, particularly OCGT peaking plant but also some CCGT. As gas price was assumed to have risen, the resultant Spot Price was also high. In the last few years wind was economic in its own right and was beginning to increase but still well short of the LRET.

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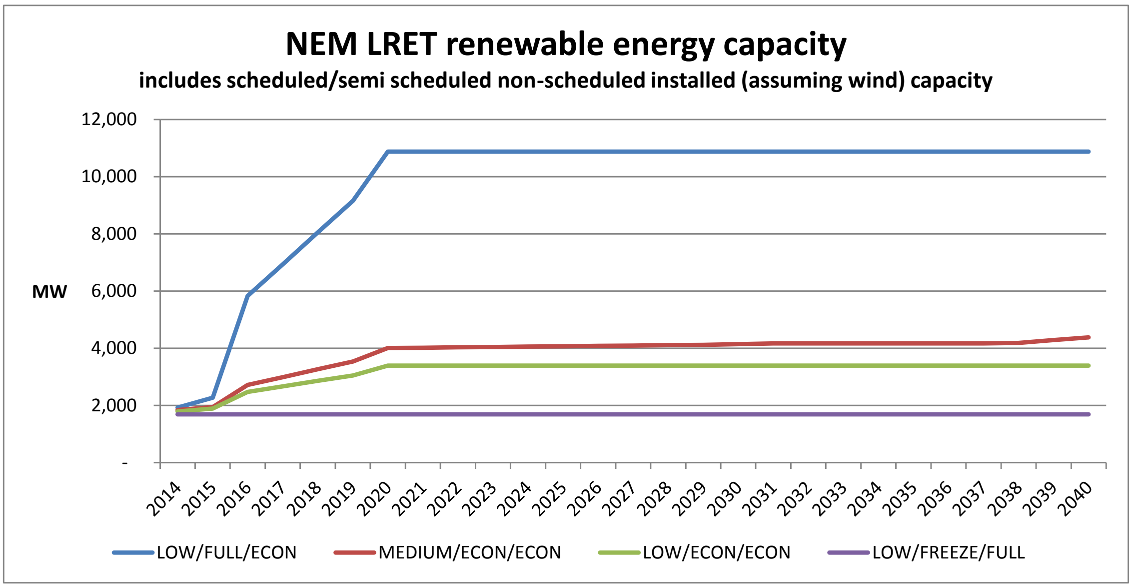
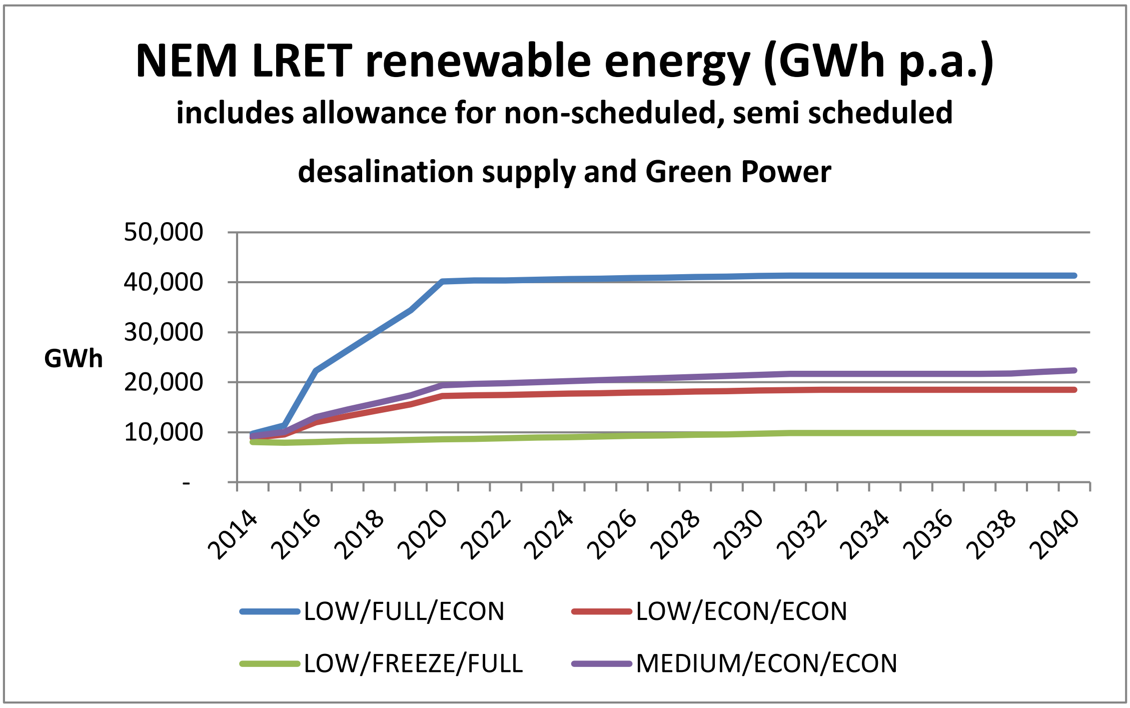
Figure 14 Installed capacity (wind) - extended scenarios



Note: The chart excludes non LRET renewable energy including pre existing hydro

Figure 15 NEM Large Scale Renewable Energy - extended scenarios



Consistent with results from phase 1 for the cases where we limited LRET investment on economic grounds, once the current stock of banked certificates was exhausted (assumed during 2015-16) and adjustment made for non-scheduled LRET plant, cases with low demand growth rate allowed approximately 45 - 50 per cent of the target to be met.[5] The equivalent level for medium demand growth rate was 50 - 55 per cent. A band of achievement has been noted as we balanced the amount of thermal capacity to withdraw and LRET to include using an iterative process and the results moved within a band due to approximations in the process.

A notable feature of the results for each case is the absence of additional investment from around 2020 even though we assumed that revenue from RECs or an equivalent arrangement would continue after 2030, albeit non indexed. The reason for this is that the effects of over-supply in generation under low load growth persist for many years. Assumptions around the availability of coal plant to return to service are therefore critical and, as noted earlier, if withdrawn coal plant is closed and therefore not available to return to service, prices will rise, potentially facilitating additional renewable entry.

Further, by the 2030s developments in solar and possibly geothermal may mean these technologies will emerge instead of wind. Accordingly one consequence of the interaction between closure of coal plant, potential growth in demand and changes in costs of renewable technologies is that the earlier these factors combine in a manner that sees a lift in wholesale energy price the more likely it is that wind will be the dominant renewable technology into this period.

In each of the cases where the LRET was not met there is a small increase in renewable energy production across different years even when no capacity is being added. This is occurring because in the early years renewable energy is being (marginally) constrained at low demand periods and as minimum demand grows this constraint is less significant. As noted in the case with medium load growth at the end of the period of analysis the combination of higher market prices and reducing capital cost of wind combine to allow wind to enter on an economic basis. If market price were to lift earlier due to faster growth in demand or closure of coal plant that was withdrawn in the earlier years of the study, renewable plant may well enter on an economic basis ahead of gas plant and thus change the mix by 2040.

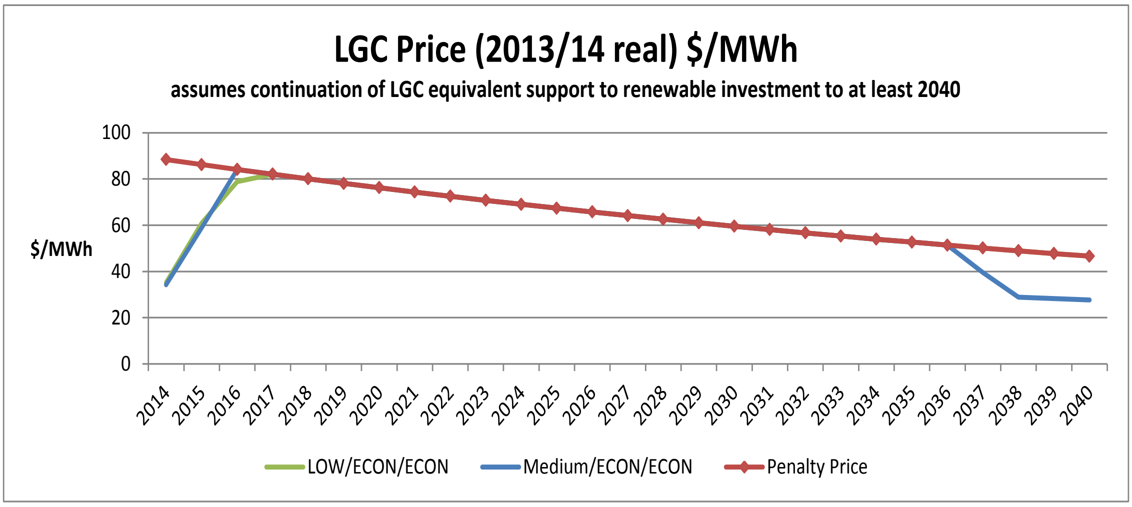
Price of LGCs

A further observation is that as the penalty price is limiting returns to new entrant renewable plant and that the price of RECs is likely to sit at the penalty price from the time carbon price is removed and the current bank of certificates is used. As noted, the existing bank is expected to be exhausted during 2015/16. The resultant price of LGCs is very similar in all cases. This may be seen as non-intuitive but is consistent with the relatively similar Spot Prices that are the result of modelling showing Spot Price will be highly dependant on the level of withdrawal of coal capacity (as gas will is expected to be reduced to take-or-pay levels for an extended period) leaving coal as the “swing” non-renewable source of generation.

5 In principle parties may optimise the value of banked LGCs by building additional plant earlier and continuing to hold the banked certificates until a later time. We did not assess this possibility.

Figure 16 shows the resultant certificate price for two representative cases where there are differences at the start and end of the period. In considering this chart it is important to note that values are shown for past 2030, this is a result of the approach agreed with esaa to assume an equivalent support for renewable investment for the purposes of the analysis to at least 2040. The certificate price before the price on carbon is removed (as assumed in the modelling) is broadly consistent with current trading prices but rises quickly as the carbon price is removed.[6]

Figure 16 Implied LGC price



7. Sensitivities and observations

7.1. Overview - NEM

The initial case with low demand growth, full LRET and all existing coal plant continuing to operate as base load but with gas restricted to expected take-or-pay volumes, produced unsustainable results that cannot be expected to occur under any realistic scenario. Notwithstanding that reliability would be high and prices low, the value of this case is to highlight that something "has to give" and the question is what and how?

6 The results are also broadly in line with modelling for the Climate Change Commission (see Fig 62 of SKM 2012) where the certificate price in the medium demand growth from the AEMO 2012 forecast sits at the LRET penalty price from 2020 (we have used the lower, low and medium growth forecasts from AEMO 2013 forecasts in these studies and hence expect to reach the penalty price earlier).

The cases where the full LRET schedule was installed and coal generation withdrawn until the remaining plants covered operating costs required approximately 2900MW of black coal and 250 MW of withdrawn brown coal plus cycling of 1400 MW under the low growth demand condition. Installation in the full LRET schedule implies funding over and above that which is likely from LGCs and the energy market under the conditions modelled. Increased revenue would flow if the penalty price under the LRET scheme were increased or higher wholesale market prices eventuate as a result of higher level of withdrawal of coal plant than we studied, for example if the target ratio for revenue to operating cost was greater than 1. In this respect it is important to note that a significant lift in wholesale price is unlikely until sufficient coal plant withdraws and or demand increases so that gas is again a dominant fuel at the margin and operating above the take or pay quantities assumed.

The position across different regions of the NEM was affected by interconnector capability and goes part way to explaining why some brown coal plant is likely to be withdrawn even though its incremental price is generally below that of black coal.

If demand grows in line with the medium growth rate forecast by AEMO, the level of coal plant that would need to be withdrawn would be less but still require a material change. In the particular cases studied and the particular combination of capacity reduction, interconnectors were less constraining under medium load growth. As a result prices across the regions of the NEM were more closely aligned. This outcome may have been a coincidence but does serve to highlight the nature of changes and possible different effects over-supply may have in different aspects of operation of the NEM.

7.2. Impact of capital cost

Cases where we balanced withdrawal of coal plant and the level of renewable investment involved lower levels of withdrawal in order to achieve a ratio of revenue:operating cost no less than 1. As the penalty price under the RET scheme is not indexed, its CPI adjusted level (i.e. the real dollar level) falls over time. As a result the learning rate for the capital cost of wind, or rate at which the capital cost falls over time as technology improves, is important. If the learning rate is slower than the fall in the CPI adjusted penalty price of a technology, progressively less of that technology will be economic unless the energy market price rises accordingly.

Information published by AEMO on learning rates for the dominant technology, wind, suggest a 30% forecasting uncertainty including allowance for estimates of future foreign exchange rate. Forecasting uncertainty therefore is to be expected and will translate to uncertainty about the economic level of renewable investment where energy market price is low. However, although there will be uncertainty about the precise amount of shortfall, if energy market price is low the shortfall will be substantial.

7.3. Maintenance effort

Reduced maintenance was shown to have some effect but even though we doubled the forced outage rate across nearly 12,000 MW of coal plant, the effect was only limited. To further examine the impact of a higher forced outage rate we also looked at whether there would be increased volatility in price or incidence of scarcity. Volatility was higher in both parameters but annual results increased only moderately. Clearly if maintenance is cut deeply enough results will eventually become excessive.

The study involved an extensive cutback in maintenance but produced a limited effect and on this basis we conclude that while maintenance reduction may undoubtedly assist individual generators, it is unlikely to be able to redress the full extent of surplus. Logically, maintenance reduction is more likely to be of benefit for situations with a smaller scale surplus.

The study showed that while withdrawal of gas plant may occur, discretionary dispatch (that is of gas plant not associated with co-generation) is already limited to higher price periods leaving coal plant as the principal discretionary plant around 75 per cent of hours per year, in shoulder and off-peak periods. Accordingly, withdrawal of gas plant would be expected to increase the price somewhat in the remaining 25% of hours but have limited effect on overall average price and hence limited impact on decisions about withdrawal of coal plant. Further, gas plant may withdraw if it cannot obtain support from retail hedges that have been assumed in developing the strategy for take or pay gas provision. Flexibility within vertically integrated and dual fuel businesses may, however, allow the businesses to take a less conservative approach: for example by seasonal cycling of availability, but not operation, of gas plant.

7.4. Orderly versus disorderly

The cases with progressive withdrawal of coal, possibly accompanied by reduced maintenance activity demonstrate an orderly response is possible. This is no surprise. However, a key question is whether an orderly withdrawal is more likely than a disorderly withdrawal given that the analysis has also shown that the scale of over-supply means it is unlikely to be adequately managed through techniques such as reduced maintenance alone.

Accordingly there is a risk of what we have labelled ‘disorderly” withdrawal. The choice of 1500MW and its location was arbitrary and not intended to suggest any particular station(s) will take this decision. However, given our conclusion that withdrawal of coal plant will be an integral part of the response on commercial grounds, a key strategic question for policy makers is whether, in all the circumstances, it is prudent to assume a disorderly type of withdrawal will not occur.

Orderly withdrawal implies that generators will respond to the commercial incentives, or more particularly forecasts of prices. For this to occur they will need to place sufficient reliance on forecasts to take major, progressive, action to withdraw sufficient capacity gradually. A market such as the NEM relies on expectations of rational economic behaviour and inherent in that is confidence in forecasts and an ability to predict competitor behaviour. The over-supply situation is occurring at a time of considerable uncertainty and responses involve multiple decisions by a number of players. There is therefore more risk than is typical that decisions may not lead to “orderly” outcomes. The scale of the affect of a disorderly response may be unacceptable. Accordingly pre-emptive action, to facilitate, or at least prepare to facilitate, orderly outcome(s) would seem appropriate.

Should a policy decision be taken to establish a safeguard to facilitate orderly response further work would be required and probably involve a combination of legal and commercial mechanisms. However, the point of this paper is to make the case for such a mechanism in principle. As discussed it would seem unlikely to be needed in the WA WEM but the potential consequences in the NEM are significant and there are impediments to the level of coordination needed at present.

Although the WA WEM has a surplus of capacity with a reserve margin well in excess of the minimum requirement, in section 5 we noted that a number of factors mitigate the impact. The market design in the WA WEM, the re-merger of Verve and Synergy together with the timing of decisions about potential age related retirement of generation plant means the potential impact of over-supply is more readily managed. Together these factors provide the opportunity and the means to, at the very least, coordinate withdrawal in an orderly manner.

7.5. Barriers to Exit

The analysis discussed in this report points to considerable pressure for generating plant to exit the market, especially in the NEM. Conventional economics suggest that when a market is oversupplied, rebalancing may occur through exit of one of the suppliers. Although availability of some power stations has been reduced (by a combination of seasonal cycling and shutdown to cold storage status), there has been limited permanent exit of plant. However, to date the level of withdrawal has not rebalanced the market suggesting further withdrawal may occur. This situation suggests there are material barriers to exit. We understand from ESAA that there are two major types of barriers to exit:

1. Direct costs of closure: Decommissioning and environmental obligations as well as employee termination costs
2. Reluctance to forego an option value in uncertain times.

These are outlined in greater detail below:

7.5.1. Direct costs of closure

Decommissioning and environmental obligations

The most significant cost of decommissioning a power station relates to environmental management requirements. Once a power station has been closed, the relevant jurisdictional Environment Protection agency (EPA) will require work to start on site remediation. Works are likely to include:

- Draining of oil from turbines and other machinery;
- Removal of asbestos and any other toxic materials;
- Demolishing of the power station and associated structure and removal of debris;
- Active environmental management of cooling lakes, ash dams and other environmental systems (potentially including ongoing pumping requirements);
- Testing of land for pollutants and soil remediation as required; and
- Ongoing ecosystem management post-demolition.

The full costs of these activities are uncertain. EPA rules change over time and so there is often no clear precedent under the current rules of what is sufficient to achieve compliance. The extent of the need for soil remediation cannot be ascertained until the buildings have been removed. While most facilities will have an asbestos register, there is a risk that more may be discovered during the demolition process.

There is little scope to materially offset the costs. At the peak of commodity prices before the global financial crisis the scrap value of metal parts more or less offset the costs of removal, but that is no longer the case. Land values are not likely to be especially high for the locations of existing power stations. Replacement with a new power station is improbable when closure has been triggered by market conditions – except in rare circumstances where the site is used to build renewable facilities not entirely reliant on market conditions. Accordingly, transmission lines, transformers and other grid connection assets will be stranded.

On the other hand closure of a plant will occur at some point. Accordingly plant owners should be assumed to have made some provision for the related costs. Bonds or bank guarantees may also have been required as a condition of the sale by state governments (for privately owned plant). However, where closure would not otherwise have occurred for some years the present value of provisions will be small. In any case it is a provision rather than a cash cost.

Exit costs are not expected to vary significantly with plant capacity. Total decommissioning and environmental costs for a power station run into the tens of millions of dollars.

Labour costs

Closure of a power station has significant implications for the ongoing employment requirements of the business. To run the plant up to the point of closure requires a certain minimum workforce, so this cannot be managed by allowing natural wastage via retirement, reallocation. There is unlikely to be significant alternative employment available within the business, given that other facilities in the portfolio will already be fully staffed. Inevitably, then, a closure due to market conditions is likely to entail redundancy. In practice the age profile of workers at thermal power stations is skewed towards older workers. As a result many employees will have significant redundancy entitlements – up to a year's salary in many cases. Given that the number of redundancies could be in the order of 70-100 per power station site redundancy related costs may be in the order of \$5-10m per station.

Other contractual costs

External labour termination costs are the most obvious example of contractual obligations that may be triggered by early closure. Depending on terms, there may be termination fees in relation to fuel supply, water supply, or transmission. Noting that the assets associated with these services may be stranded as a result of a retirement of plant.

Mine mouth power stations

Where a power station has its own dedicated fuel source, retirement costs are likely to be exacerbated unless an alternative buyer can be found for the fuel (coal). In the context of existing oversupply, this is unlikely. Brown coal is particularly problematic in this respect given safety issues associated transporting it. In the case of black coal, the quality is often below export grade coal and there may not be transport infrastructure in place in any case.

If an alternative use for the mine cannot be quickly found, it too will require decommissioning and environmental management. Costs can be significant, especially if closure takes place much earlier than expected as the placement of overburden and other material is planned around the original expected life of the mine in order to facilitate rehabilitation at that point. Under earlier closure the plan will not be as effective and so rehabilitation costs may be higher as well as being brought forward.

Employees who work at the mine may also face redundancy.

7.5.2. The option value of avoiding permanent closure

In the current oversupplied market, the owners of unprofitable plant have three broad options:

3. Keep running – possibly at a lower utilisation level than previously, and attempt to make enough revenue to cover their costs - at least short run costs, although the studies identified that this was unlikely to be possible for all plant under the conditions examined;
4. Mothball a plant – with a view to returning it to service when conditions improve;
5. Permanently close

The key difference between the first two and the third is that the first two allow the possibility of a return to profit if market conditions improve. The NEM is a highly transparent market, given the wide range of information published by AEMO and participants have a sophisticated understanding of the variables that affect their revenue. Given this, it might seem that the point at which a plant is no longer likely to make a profit over its expected lifespan is relatively predictable. But there is currently a range of uncertainties that complicate such judgments with the effect of increasing the option value of one of the options that avoids permanent retirement. The uncertainties relate to:

- Demand has turned down after several decades of largely steady growth. The downturn was not anticipated but has led AEMO to repeatedly revise their forecasts down over several years due to reduction in underlying trends and a number of one-off large industrial closures;
- Climate change and carbon policy, which has a material influence on the industry, is in flux. The industry is facing its third iteration in five years, with Direct Action set to replace the Clean energy Future, which followed the CPRS (which was legislated). Given the fundamental differences between the major political parties, further changes in the near future cannot be ruled out.
- The quantum of mandatory renewable energy that will enter the market under the Renewable Energy Target RET is uncertain. The RET has also faced multiple reviews and amendments since the enhanced target was set in 2009, and the latest review has just commended (February 2014).
- Although gas is not as significant a fuel as coal, it has provided up to 15 per cent of generation. However, the east coast gas market is in a state of transition as large export projects that will triple demand come on stream, major price renegotiations occur and mandated gas use policy expires (Queensland Gas Scheme was closed in December 2013) .

In combination these uncertainties are unprecedented and well in excess of normal business uncertainty. Uncertainty is heightened as the generation fleet is owned and controlled by a number of public and private sector entities who must each make decisions about their portfolios. An available or even mothballed plant also offers a hedge against a long-term unexpected outage in the rest of a participant's portfolio.

Strategically individual generators may also be trying to avoid first mover disadvantage created by being amongst the parties to withdraw and incur the shutdown costs but thereby improve the commercial position of their competitors. In combination the barriers create incentives for generators to hang but in the process create risks of "dis-orderly withdrawal.

Appendix A: Input data and information

This appendix provides a listing of data sources where the information is voluminous and readily available from public industry sources and lists other items. Key data items and modelling assumptions were agreed with esaa in an Assumption Book at the commencement of the work.

Demand:

NEM: AEMO National Electricity Load Forecasting Report. See -
http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013

WA WEM: IMO Statement of Opportunities. See –

http://www.imowa.com.au/docs/default-source/Reserve-Capacity/soo_2013_rev1.pdf?sfvrsn=2

Renewable Energy requirements: Sourced from AEMO National Electricity Load Forecasting Report. Summarised in Table 7. See -

http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013

LGC bank drawdown: OGW calculations derived from Table 7, contribution of non-scheduled generation from AEMO (ibid) and initial bank of LGC derived from interpolation of available data for financial year anlaysis base – see Table 8.

Generation:

NEM: AEMO

http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information

http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions

WA WEM:

OGW internal database (see Table 8)

IMO Capacity Credit reports. See - http://www.imowa.com.au/reserve-capacity/capacity-credit-information

IMO price limit notifications. See - http://www.imowa.com.au/market-reports/price-limits

Fuel.

OGW internal database

Table 7 Net renewable energy requirements (GWh)

	LRET			GreenPower		Renewable supply (desal)		Net Renewable requirement	
Calendar Year	Australia Wide	NEM	SWIS	NEM	SWIS	NEM	SWIS	NEM	SWIS
2013	19,088	16,988	1,603	1,905	-	1,782	568	20,675	2,171
2014	16,950	15,086	1,424	1,962	-	1,764	568	18,812	1,992
2015	18,850	16,777	1,583	2,021	-	1,747	568	20,544	2,151
2016	21,431	19,074	1,800	2,081	-	1,729	568	22,884	2,368
2017	26,031	23,168	2,187	2,081	-	1,712	568	26,961	2,755
2018	30,631	27,262	2,573	2,081	-	1,695	568	31,038	3,141
2019	35,231	31,356	2,959	2,081	-	1,678	568	35,115	3,527
2020	41,850	37,247	3,515	2,081	-	1,661	568	40,989	4,083
2021	41,000	36,490	3,444	2,081	-	1,661	568	40,232	4,012
2022	41,000	36,490	3,444	2,081	-	1,661	568	40,232	4,012
2023	41,000	36,490	3,444	2,081	-	1,661	568	40,232	4,012
2024	41,000	36,490	3,444	2,081	-	1,661	568	40,232	4,012
2025	41,000	36,490	3,444	2,081	-	1,661	568	40,232	4,012
2026	41,000	36,490	3,444	2,081	-	1,644	568	40,216	4,012
2027	41,000	36,490	3,444	2,081	-	1,628	568	40,199	4,012
2028	41,000	36,490	3,444	2,081	-	1,612	568	40,183	4,012
2029	41,000	36,490	3,444	2,081	-	1,595	568	40,167	4,012
2030	41,000	36,490	3,444	2,081	-	1,580	568	40,151	4,012

Table 8 LGC Bank drawdown

	Net NEM renewable requirement	Non-scheduled renewable generation	Existing NEM scheduled	LGC Bank
				33,000
2013	20,675	4,507	2,701	19,533
2014	18,812	5,407	2,807	8,935
2015	20,544	5,407	2,913	-

Table 9 WA WEM generation data

	Installed Cap	Aux	FORate	Maint Factor	VOM $/MWh s/out	FOM $/yr/MW installed	HeatRate GJ/MWh s/out	Total emission factor (Combustion + fugitives)kg CO2-e/GJ of fuel
Albany	22	0.0%	0.0%	0.0%	1.00	20,000	-	0.0
Alcoa_Wagerup_Cogen	25	1.0%	3.0%	6.0%	1.30	33,000	11,000	58.3
Bluew aters	441	7.4%	3.5%	7.0%	1.30	55,000	10,600	95.4
PPP_Kw inana_cogen	80	2.0%	3.0%	6.0%	1.30	33,000	11,000	58.3
Cockburn	246	2.4%	3.0%	6.0%	1.30	33,000	7,500	58.3
Collie	330	7.9%	3.5%	7.0%	1.30	55,000	10,600	95.4
Emu_dow ns	80	0.0%	0.0%	0.0%	1.00	20,000	-	0.0
Geraldton	21	0.5%	3.0%	5.0%	10.00	14,000	12,000	73.2
West Kalgoorlie	53	0.5%	3.0%	5.0%	10.00	14,000	12,000	73.2
Southern Cross	0	0.5%	3.0%	5.0%	10.00	14,000	12,000	58.3
Kemerton	310	0.5%	3.0%	5.0%	10.00	14,000	12,000	58.3
Kw inana_C	385	4.0%	5.5%	5.0%	1.20	55,000	11,000	58.3
Kw inana_GT	21	0.5%	3.0%	5.0%	10.00	14,000	12,000	58.3
Muja_C	404	8.5%	3.5%	7.0%	1.50	55,000	11,000	95.4
Muja_D	461	8.5%	3.5%	7.0%	1.50	55,000	11,000	95.4
Mungarra	113	0.5%	3.0%	5.0%	10.00	14,000	12,000	58.3
Neerabup_Peaker	330	1.0%	3.0%	5.0%	10.00	14,000	11,500	58.3
New gen_Kw inana _CCGT	245	2.0%	5.0%	4.0%	1.10	33,000	7,500	58.3
New gen_Kw inana_Peaking	82	2.0%	3.0%	5.0%	10.00	14,000	11,250	58.3
Parkeston_SCE	68	0.5%	3.0%	5.0%	10.00	14,000	12,000	73.2
Pinjar_A_B	228	0.5%	3.0%	5.0%	10.00	14,000	12,000	58.3
Pinjar_C	233	0.5%	3.0%	5.0%	10.00	14,000	12,000	58.3
Pinjar_D	124	0.5%	3.0%	5.0%	10.00	14,000	12,000	58.3
Pinjarra_Alinta_Cogen	280	2.4%	3.0%	5.0%	1.30	33,000	10,000	26.3
Tiw est_Cogen	37	1.5%	3.0%	5.0%	1.30	33,000	10,000	58.3
Wagerup_Alinta_Peaker	323	0.5%	3.0%	5.0%	10.00	14,000	12,000	73.2
Walkaw ay	89	0.0%	0.0%	0.0%	1.00	20,000	-	0.0
Worsley_SWCJV	116	2.0%	3.0%	6.0%	1.30	33,000	11,000	26.3
Collgar	206	0.0%	0.0%	0.0%	1.00	20,000	-	0.0
~~Muja_AB~~	~~220~~	~~8.5%~~	~~3.5%~~	~~7.0%~~	~~1.30~~	~~55,000~~	~~10,000~~	~~95.40~~
Kwinana_B_HEGT	200	2.0%	3.0%	5.0%	10.00	14,000	9,000	58.3
Merridin	74	1.0%	3.0%	5.0%	10.00	14,000	12,000	58.3
PerthEnergy_Kw inana_GT1	120	2.0%	3.0%	5.0%	10.00	14,000	9,500	58.3
Aggregated small w indfarm	79.4	0.0%	0.0%	0.0%	1.00	20,000.00	-	0
Aggregated small Renw able	10	0.0%	0.0%	0.0%	1.00	20,000.00	-	0
Aggregated small LFG	15	0.0%	3.0%	5.0%	10.00	14,000.00	13,000.00	5
Aggregated small liquid fuel	39.6	0.0%	3.0%	5.0%	10.00	14,000.00	13,000.00	73.2

Table 10 Operating constraints to manage fuel

Market	Station	Operating constraint	Comments
NEM	Tallawarra to 2015	70%	Minimum annual capacity factor
NEM	Tallawarra from 2015	17%	Minimum annual capacity factor
NEM	Braemar to 2015	40%	Minimum annual capacity factor
NEM	Braemar from 2015	10%	Minimum annual capacity factor
NEM	Braemar 2 to 2015	20%	Minimum annual capacity factor
NEM	Braemar 2 from 2015	5%	Minimum annual capacity factor
NEM	Condamine to 2015	40%	Minimum annual capacity factor
NEM	Condamine from 2015	10%	Minimum annual capacity factor
NEM	Darling Downs	55%	Minimum annual capacity factor
NEM	Darling Downs from 2015	14%	Minimum annual capacity factor
NEM	SwanbankE to 2015	52%	Minimum annual capacity factor
NEM	SwanbankE from 2015	13%	Minimum annual capacity factor
NEM	Torrens Island A to 2017	10%	Minimum annual capacity factor
NEM	Torrens Island A from 2017	3%	Minimum annual capacity factor
NEM	Torrens Island B to 2017	30%	Minimum annual capacity factor
NEM	Torrens Island B from 2017	8%	Minimum annual capacity factor
NEM	Pelican Pt to 2017	64%	Minimum annual capacity factor
NEM	Pelican Pt from 2017	16%	Minimum annual capacity factor
NEM	Tamar Valley to 2017	68%	Minimum annual capacity factor
NEM	Tamar Valley from 2017	17%	Minimum annual capacity factor
NEM	Smithfield	90%	Plus minimum generation 50%
NEM	Osborne Cogen	73%	Minimum annual capacity factor
NEM	Yabulu (nickel plant)	36%	Minimum annual capacity factor
NEM	Yarwun Cogen	87%	Minimum generation 60%
WEM	Alinta WGP	Flat 10MW	Approx. for 8-12MW range in practice
WEM	Alinta PNJ	Flat 65MW	
WEM	Worsely	Flat 58MW	
WEM	Ti-West	Flat 10MW	
WEM	PPP-KCP-EG1		Minimum generation 25MW