Wholesale electricity market performance report 2018

LCOE modelling approach, limitations and results

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AUSTRALIAN ENERGY REGULATOR

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Shortened forms

Shortened Form	Extended Form
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CCGT	Combined cycle gas turbine
CPI	Consumer price index
EOH	Equivalent operating hours
EPC	Engineering procurement and construction
FOM	Fixed operation and maintenance costs
LCOE	Levelised cost of energy
MEU	Major Energy Users Inc.
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net present value
OCGT	Open cycle gas turbine
PDC	Price duration curve
RDC	Revenue duration curve
RICE	Reciprocating internal combustion engine
RRP	Regional reference price
TNSP	Transmission network service provider
VOM	Variable operation and maintenance costs
WACC	Weighted average cost of capital

Introduction

To inform the AER's assessment of wholesale market performance, one factor we must consider is if wholesale prices are determined in the long run by underlying costs. In our *Wholesale electricity market performance report 2018 (the performance report)* we used levelised cost of energy (LCOE) estimates for this assessment of price trends.[1] These estimates formed part of one indicator that we considered alongside a broad range of other factors in assessing the effectiveness of competition and efficiency of the market.

This technical paper is complementary to the analysis in the performance report. While the performance report contains the high level results of the analysis and calculations performed, this technical paper explains the method underlying the calculations and assessment and more detailed results.

Background

The National Electricity Law (NEL) requires the AER to monitor the wholesale market and report on its performance at least every two years.[2] We are required to identify and analyse whether:

- there is 'effective competition' within the relevant wholesale market, as defined in the NEL,
- there are features of the market that may be detrimental to effective competition within the market,
- there are features of the market that may be impacting detrimentally on the efficient functioning of the market and the achievement of the national electricity objective.

This monitoring and reporting role supports the efficient operation of the wholesale electricity market as it allows early detection of issues affecting market performance.

Staff working paper

On 15 June 2018, we released *a Staff working paper on 2018 approach to LCOE analysis*. This paper contained a brief technical discussion around the expected use of LCOE and its limitations, and invited comments from interested stakeholders.

This technical paper expands on the information in the Staff working paper, and explains in greater detail the method and assumptions underlying the calculations and assessment. Our responses to stakeholder comments are in Appendix A.

1 AER, Wholesale electricity market performance report 2018.

2 National Electricity Law, Part 3, Division 1A.

1 What did we do?

In an efficient, competitive market, with free entry and exit, we might expect prices to move broadly in line with underlying costs. In this market, if prices persist above underlying costs, investors will see an opportunity and enter the market, driving the price down. Alternatively, if prices persist below underlying costs, it will eventually become unprofitable for high-cost firms to remain in the market, and they will leave. Over time this will cause the price to rise.

However, the underlying costs faced by a new entrant are unknown. Therefore, to undertake a comparison of price and costs, we must estimate the costs of establishing new generation. After consultation with stakeholders we decided that for the 2018 performance report, we would use LCOE estimates.[3]

An LCOE and price comparison compares a new entrant generator's costs, levelised across the time it operates, to the average price that generator could expect to receive depending on when it generates. If that price exceeds the costs, there may be an incentive for new entry.

LCOE is a common estimation technique used for comparing the lifetime costs of different generation technologies. In its simplest form, LCOE is calculated as a new entrant generator’s expected lifetime costs divided by its lifetime energy production. We chose LCOE for its simplicity, which makes it accessible, transparent and comparable. Being a simple technique, it is sensitive to input assumptions. To account for this sensitivity, we constructed high and low cost scenarios for each technology.

Its simplicity means that there are a number of limitations and any results must be interpreted with care. Provided we are mindful of these issues, we can use LCOE to understand trends over time and use this information to support our assessment of the performance of the market alongside a range of other tools and analysis.

1.1 What did we compare?

For our analysis, we surveyed a range of publically available data on new entrant costs, collating results to produce high (worst case) and low (best case) estimate scenarios for each technology type. Using a number of assumptions, we then calculated the LCOE across a range of capacity factors, rather than assuming a single value.

In most cases, we compared LCOE to potential revenue in each NEM region for the 2014-15 and 2017-18 financial years. In cases where there is a practical limitation to the entry of a particular technology (for example, the unavailability of brown coal sources), we have only included those regions where the new entry is plausible in the comparison. We estimated LCOE on the basis of no subsidies being available for any generation technology type.

1.2 What did we not compare?

[3] AER, 2018 Focus - Wholesale electricity market performance monitoring - March 2018.

We have not included storage technologies (such as batteries and pumped hydro storage) at this time because successfully estimating the levelised cost of storage would require more detailed modelling. This modelling would need to consider the optimisation of the behaviour of the storage facility – acting as a load when charging prior to acting as a generator when discharging.

Pumped hydro storage is more complex as it must also consider environmental water flow obligations as a primary determinant of generation strategy – from both a resource management, and opportunity cost of generation perspective. As such, to accurately estimate costs for hydro technology would require detailed, site specific modelling.

Stakeholders highlighted storage technologies in particular as an area of opportunity in coming years, and there has been some investment already, with more committed.[4] As the role and presence of storage grows in the market, we will explore ways to include these costs in our estimations in future reports. We will also consider how these technologies can best combine and interact with other forms of generation.

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[4] See section 5.1 of the *Wholesale electricity market performance report 2018*.

2 Levelised cost of energy

LCOE measures the average cost of building and operating a new generator of a specific technology over its assumed life cycle. In estimating LCOE, the costs of investment and operation of the new generator are recovered across the time it is in operation. It follows that LCOE can be seen as the average minimum cost for a new generator to sell its electricity in order to break even over its lifetime.

For the 2018 performance report, we estimated LCOE for the following technologies:

- Onshore wind (wind)
- Non-tracking solar photovoltaic (solar)
- Black coal supercritical boiler (black coal)
- Brown coal supercritical boiler (brown coal)
- Combined Cycle Gas Turbine (CCGT)
- Open Cycle Gas Turbine (OCGT)
- Reciprocating Internal Combustion Engines (RICE) - using natural gas fuel

We do not include regional cost differences for construction, transmission, land values etc. in our estimations. We accounted for project cost variations by examining higher cost and lower cost scenarios, resulting in two LCOE curves being created for each technology.

In developing our approach, and determining values for input parameters we reviewed a number of sources. Full references to these sources are in Appendix B.

2.1 Methodology

2.1.1 LCOE formula

The simple algorithm at the core of the LCOE calculation is shown in figure 1: [5]

Figure 1 - LCOE formula

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

5 AEMO, South Australian fuel and technology report - South Australian advisory functions. March 2018.

r = discount rate (percent)

n = life of the asset (years)

$\mathrm{I_t}$ = Investment expenditure in the year t

$\mathrm{M_t}$ = Operations and maintenance expenditure in the year t

$\mathrm{F_t}$ = Fuel expenditure in the year t

$\mathrm{E_t}$ = Electricity generation in the year t

2.1.1.1 Assumptions

Underlying the formula we use in calculating LCOE are the following assumptions:

- Net present value (NPV) is a common formula and is therefore not repeated here.
- Costs include:
    - Financing – We assume project funding as the method used to pay for capital costs. During the construction period, we assume the payment schedule to be a constant percentage applied to each year of construction with compounding interest. This forms the value of the loan, which is to then be paid off over the life of the loan.
    - Capital costs include engineering, procurement and construction (EPC) for both generation and balance of plant (BOP) equipment.[6] The capital costs perimeter is taken to be the boundary of the power station, and includes capital costs to EPC, commission, and to get the site "generation ready". We also assume fuel arrives at the generator in the correct state for use, with no delivery or processing costs.
    - Fixed and variable operating and maintenance costs – Fixed costs are independent of capacity factor and inflate at the consumer price index (CPI) rate. Variable costs are dependent on capacity factor and inflate at CPI rate.
    - Fuel costs – Fuel costs are upper and lower bounds of recent actual fuel prices.
    - Major overhaul costs – Major overhauls are defined as those that return the machines to the same residual life as a new machine. Overhaul costs are dependent on equivalent operating hours (EOH) and inflate at CPI rate. This is not a perfect assumption, as overhaul costs may decrease with parts substitution and economies of scale, however we use it for simplicity.
- Costs don't include:
    - The construction of new transmission lines, or the lines from the station to the nearest transmission network service provider (TNSP) connection point.
    - Fuel transmission or transportation costs. For example, construction of train lines to bring coal to the generation site.

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6 BOP is a term generally used to refer to the supporting components of a power plant needed to deliver the energy other than the actual generation unit itself.

- Land or other site specific expenses.
- Exit costs – Site remediation less scrap value.

- Costs are averages and are therefore not adjusted for site specific or region specific factors. Costs may vary significantly between regions and specific sites.
- Forced outage rates are assumed. These are defined as breakdown or other outage periods when operation would otherwise have occurred.

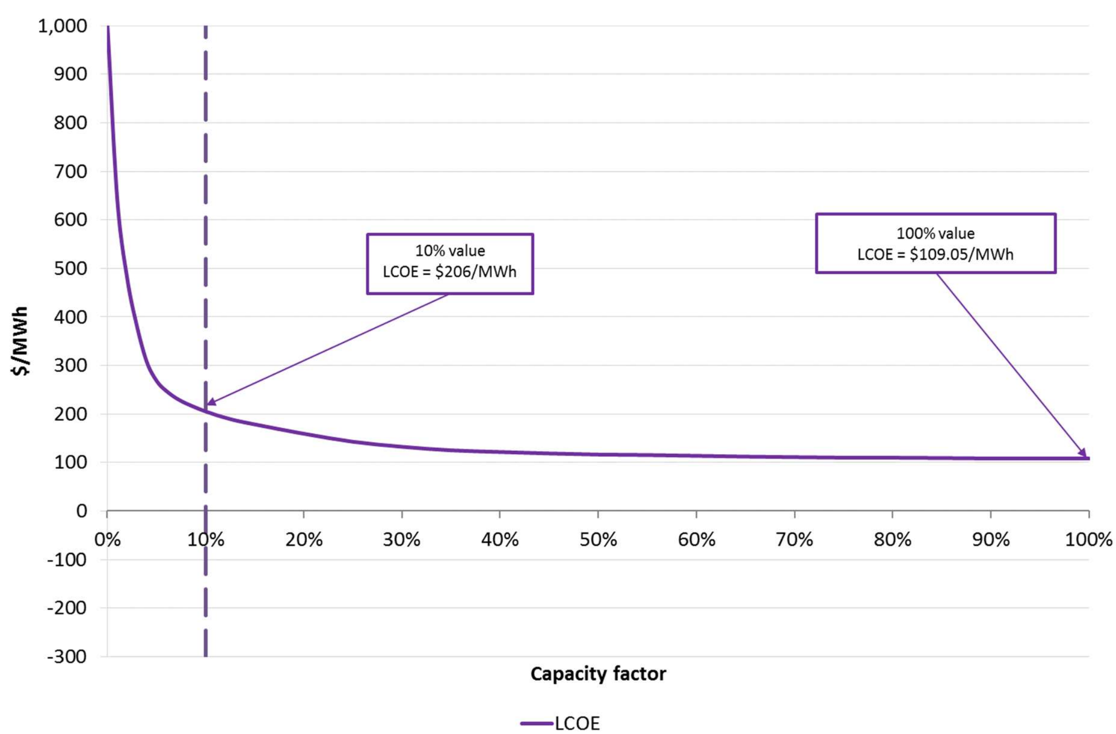
2.2 Inputs

Generators face variable and fixed costs and LCOE includes estimates for both. There are also a number of other important input parameters into the LCOE calculation.

2.2.1 Capacity factor

The capacity factor is an important input parameter in calculating LCOE values. The capacity factor is the amount of energy produced by a generator as a proportion of its maximum possible production over a given period (for our purposes, annually). This parameter is significant in the LCOE calculation as the fixed costs associated with generation are allocated across each megawatt-hour of energy produced. For this reason we calculate LCOE across a range of potential capacity factors. This results in a curve of possible LCOE values, rather than a single figure, as illustrated simply in Figure 2:

Figure 2 - LCOE curve



In figure 2, for a generator producing 10 per cent of the year, its levelised costs are $206/MWh. Similarly, if the generator in figure 2 produces all the energy it can for the entire year, its levelised costs equate to the value of the LCOE curve evaluated at 100 per cent of hours, or around $109/MWh.

2.2.1.1 Capacity factor formula

Figure 3 – Capacity factor formula

$$Capacity\ Factor = \frac{Energy\ sent\ out\ (MWh}{365\ (days) \times 24\ (hou\quad) \times nameplate\ rating\ (MW)} \times 100\ (per\ cent)$$

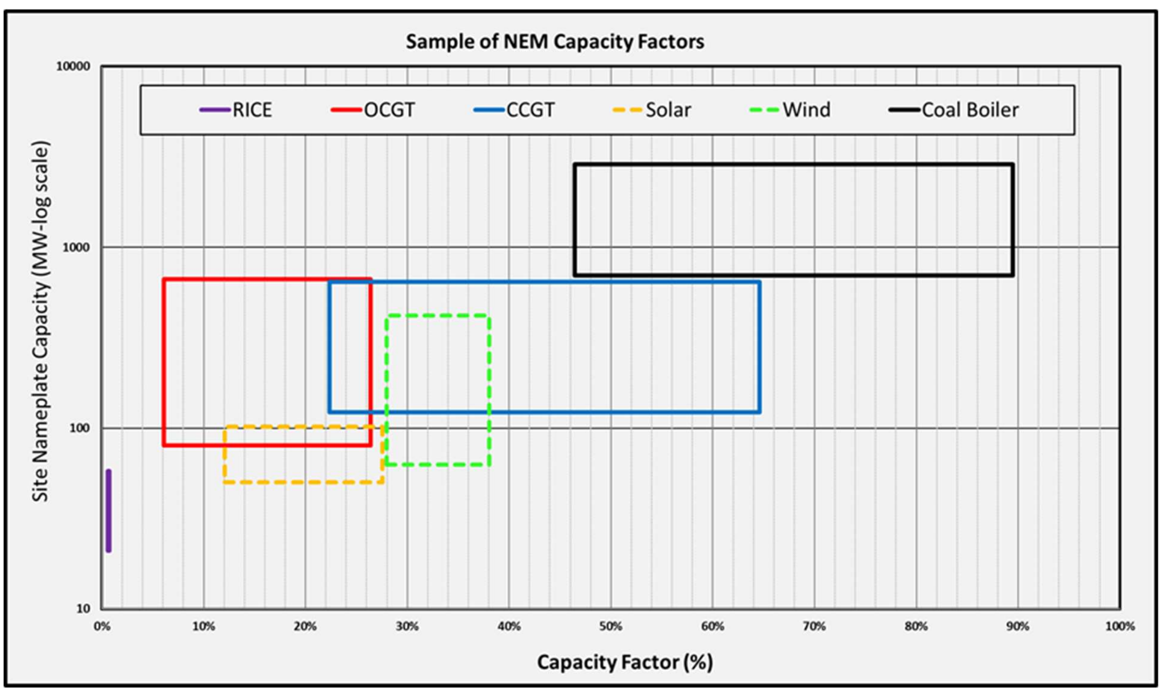
2.2.1.2 Assumptions

We do not account for differences in results that may be caused by leap years, or the variance between actual output (which may vary with site ambient conditions) and nameplate capacity. Therefore we use nameplate rating in the calculation, for simplicity.

2.2.1.3 Maximum capacity factors

While we aren't assuming a single capacity factor, we acknowledge that there are various practical limitations that place an effective maximum on the capacity factors for a particular generation technology. Figure 4 shows the range of typical operational capacity factors we observed for existing units in the NEM.

Figure 4 - Indicative capacity factors in the NEM[7]



Source: AER

7 AER Analysis, Origin Energy Annual Report 2017.

For our model construction, we have truncated our LCOE curves at the following capacity factors:[8]

- Wind - 50 per cent
- Solar - 40 per cent
- Black coal - 90 per cent
- Brown coal - 90 per cent
- CCGT - 65 per cent
- OCGT - 30 per cent
- RICE - 80 per cent

The capacity factors we truncate our curves at differ from the indicative NEM capacity factor maximums shown in Figure 4 because:

- Wind – Costs and efficiencies are improving and are moving to deliver higher capacity factors at lower costs.[9]
- Solar – We have truncated the LCOE curves at 40 per cent for solar which is an optimistic level for current technology. It is possible that future cost reductions in solar cells will mean that future solar farms will have an excess of solar panels compared to the size of the inverters. This means that the inverter may become the controlling device for the amount of energy dispatched from the site, which will lead to increased capacity factors and a changed production curve (because the over build of panels might offset the impact of unfavourable sun angles).
- OCGT – The shift to five minute settlement and the increased penetration of intermittent renewables will support the expanded use of flexible generation technologies, such as OCGT. This may lead to operation at higher capacity factors.
- RICE – The low capacity factors observed by RICE generation in the NEM is typical of this technology but potential future use for firming intermittent generation may mean a roughly 50 per cent capacity factor may be more appropriate. However, we have modelled up to 80 per cent capacity factor for comparison purposes.

For the remainder (black coal, brown coal and CCGT) we truncate at the same point as the indicative capacity factor maximums show in Figure 4. This is because these technologies are mature and we don't expect to see any significant increases in operational capacity factor.

2.2.2 Considerations in NPV cash flow calculation

We consider the following in our NPV calculation:

- Currency is nominally in 2017 Australian dollars.

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8 These capacity factors are not intended to be interpreted as the actual capacity for that technology, but rather the point at which we truncated the curves for presentation purposes.

9 https://reneweconomy.com.au/new-australian-wind-farms-reach-nearly-50-capacity-factor-99179, (3 April 2018)

- Discount rate used is Weighted Average Cost of Capital (WACC).
- Capital construction costs are to go from a greenfield site, to a generation ready power station, including EPC and commissioning.
- The number of years over which capital costs are to be spread. For example, a wind farm may take 18 months to spend all its capital in getting generation ready, whereas a coal plant may take five years or more.
- We assume a plant's construction costs commence at the start of the first year of generation. Plant that take several years to build are unable to distribute expenses incurred during construction against generation, as the plant has yet to commence generating. This does not suit the mechanics of the LCOE calculation, so we have made an additional modification:
  - Our method compounds the interest from the progressive drawdown of capital during the construction periods and then amortises this capital, plus interest, over the payback period of the load, commencing from the first year of production.
  - The economic life commences in the first year after completion, which is the first year of generation. For example, if a power station takes 5 years to build, the amount to be amortised will be the capital cost plus five years of compounded interest all applied in the first year of generation.
- Fixed operation and maintenance (FOM) costs are all costs that are independent of operating the generator, such as rent, licenses, wages etc. We increase these annually in line with the CPI assumption.
- Variable operation and maintenance (VOM) costs are all costs that are zero if the generator doesn't operate, excluding fuel. We increase these annually in line with the CPI assumption.
- For natural gas, brown coal and black coal fuel costs, we have used an upper and lower bound of recent fuel prices.
- Major overhaul costs return the machine to 'as new' condition in terms of residual life. They are expensive, might typically cost 20-30 per cent of a replacement machine and may take weeks or months to complete. We increase these costs annually in line with the CPI assumption.
- We do not account for minor overhauls or inspections.
- Economic life of the assets.
- We do not model exit costs.

2.2.3 Weighted average cost of capital

WACC is a critical input because the NPV calculation uses it to discount all future cash flows. Debt to equity ratios inform WACC, but are not a fundamental input for the LCOE estimations.

WACC is dependent on the capital structure of a company and its firm specific return on equity, and cost of debt. As we cannot know these values for a "levelised" company, we have made some bounded assumptions in understanding the WACC range.

For our purposes in estimating new entrant LCOE, we will use a WACC range of 6–8.5 per cent.

For calibrating our assumption:

- In electricity networks determinations, the AER uses WACC of between approximately 6 to about 6.5 per cent.[10]
- AEMO uses a single rate of 6 per cent in the 2018 ISP[11]
- International Renewable Energy Agency (IRENA) in 2017 used a WACC range of 7.5–10 per cent[12]

We consider it reasonable to use a WACC range of 6–8.5 per cent. This is lower than IRENA's values, but not higher. It is also higher than AEMO's values, but not lower. Proven technologies would attract a lower WACC with the converse for unproven technologies.

2.2.4 Heat rate and fuel cost

Heat rate is the parameter used to calculate the amount of fuel needed for the energy sent out. This allows fuel costs to be calculated as a function of electrical energy generated. We then include fuel costs in the NPV calculation.

2.2.4.1 Heat rates

Heat rate is defined as the ratio between thermal energy inputs to electrical energy outputs. It is a commonly used term in relation to power stations to indicate plant efficiency. Heat rate and efficiency are inversely related: a low heat rate equals a high efficiency and vice versa, as shown in Figure 5.

Figure 5 – Heat rate and efficiency formulas

$$Heat\ rate = \frac{3.6}{\text{efficiency}} \quad \text{and} \quad Efficiency = \frac{3.6}{\text{heat rate}}$$

We have used the heat rates/efficiencies in AEMO's 2018 ISP as a guide for our LCOE estimations where appropriate, but we have also considered improvements offered by new technological advances. We ignore any heat rate change during unit turn down or during start/stop ramping for simplicity.

We treat reciprocating engine heat rates as about 8.0–9.5 GJ/MWh (38–45 per cent efficiency).[13]

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10 For example, in the recent Endeavour Energy Draft decision, the AER used a nominal WACC of 5.96 per cent, down from a nominal WACC of 6.74 per cent used in the previous regulatory period.

11 AEMO, Integrated System Plan. 2018.

12 International Renewable Energy Agency (IRENA), 2018. Renewable Power Generation Costs in 2017.

13 Catalogue of CHP Technologies, US Environmental Protection Agency, Combined Heat and Power Partnership (Sept

Finally, we treat wind and solar technologies as being 100 per cent efficient because they have no fuel costs to consider.

2.2.4.2 Fuel costs

To calculate fuel costs we use the formula in Figure 6:

Figure 6 – Fuel cost formula

$$Fuel\ cost(A\$) = Commodity\ cost(A\$/GJ) \times heat\ rate(GJ/MWh) \\ \times electricity\ sent\ out(MWh)$$

We consider black coal (QLD and NSW), brown coal (Victoria) and natural gas as input costs for their respective technologies and include them here as an upper or lower value only, rather than trying to predict forward commodity prices over the next 30 years.

2.2.5 CPI

We examined CPI data from the Australian Bureau of Statistics, but we acknowledge that some costs are not correlated to the Australian economy alone. Therefore, for our estimations, we use a 2–4 per cent range for CPI inflation.

2.2.6 Equivalent operating hours

We ignore any accelerated consumption of machine life during high wear periods (such as peak power modes, fast start/stop cycles or similar). For our purposes:

- EOH are actual operating hours when energy is being sent out.
- After a major overhaul, EOH are reset to zero.
- Overhaul costs are increased annually in line with the CPI assumption.

2.2.7 Lead time for construction and payment milestones

We have used AEMO's data for construction lead time by technology.[14] However, the spend profile during the construction period is unclear in that data. Because the model needs to contemplate various construction time frames, we distribute the capital expenditure spend on an equal and constant percentage basis. For example, if it is a four year build, then we will apportion the costs as 25 per cent for each year of construction.

The accrued interest for each of those construction years will be compounded with the initial loan value and then the repayment will be made over the payback period of the loan, commencing in the first year of generation.

2017).

14 AEMO, Integrated System Plan Workbook. 2018.

3 Price Duration Curve and Revenue Duration Curve

A key challenge with using prices as a point of comparison with estimates of underlying costs is that the spot price for each trading interval varies. So, depending on when a generator is operating, it will receive a different average price for its production. If it were to operate at full power for the entire year and receive every price, on average it would receive the time weighted average price for the year.

However, generators do not necessarily run at full name plate output, or for the entire year. Many operational requirements may contribute to this, including:

- the need to reduce output to match demand targets
- fuel availability
- maintenance schedules
- unplanned outages
- performance deterioration due to normal use wear and tear
- ambient conditions effects

A generator will generally only run when prices are at a level that allow it to at least recover its costs. Therefore, it is important to account for the average price a generator may receive over the hours that it runs, to determine potential earnings.

In recognition of the relative contribution of the changing spot price to the average annual price, we construct a Price Duration Curve (PDC) and from that we derive a Revenue Duration Curve (RDC)[15].

For the 2014-15 and 2017-18 financial years, we calculate a separate PDC and RDC for each NEM region:

- Queensland
- New South Wales
- Victoria
- South Australia
- Tasmania

We also construct separate PDC and RDC, by region, for solar and wind technologies, to reflect the prices those intermittent technologies receive. We discuss this further in section 3.3.1.

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15 Wholesale electricity market performance monitoring - Staff working paper on 2018 approach to LCOE analysis (June 2018)

3.1 Price Duration Curve

The PDC illustrates the proportion of hours in which prices achieve a given level. It is a curve that shows the distribution of trading interval wholesale energy prices in descending order. We calculate the PDC across a full financial year.

3.1.1 Data processing approach

In calculating the PDC, we take the following steps:

1. Take the regional reference price (RRP) for each region for every 30 minute period.
2. Sort RRPs from highest to lowest value.
3. Plot RRPs across a zero to 100 per cent time base for the full financial year.

3.2 Revenue Duration Curve

The RDC is derived from the PDC and indicates the average price that prevails in those hours. In an ideal sense, it determines the average spot earnings a participant could receive (per MWh) by operating only when prices are at, or above a particular level. Like PDC, we calculate RDC across a full financial year.

3.2.1 Data processing approach

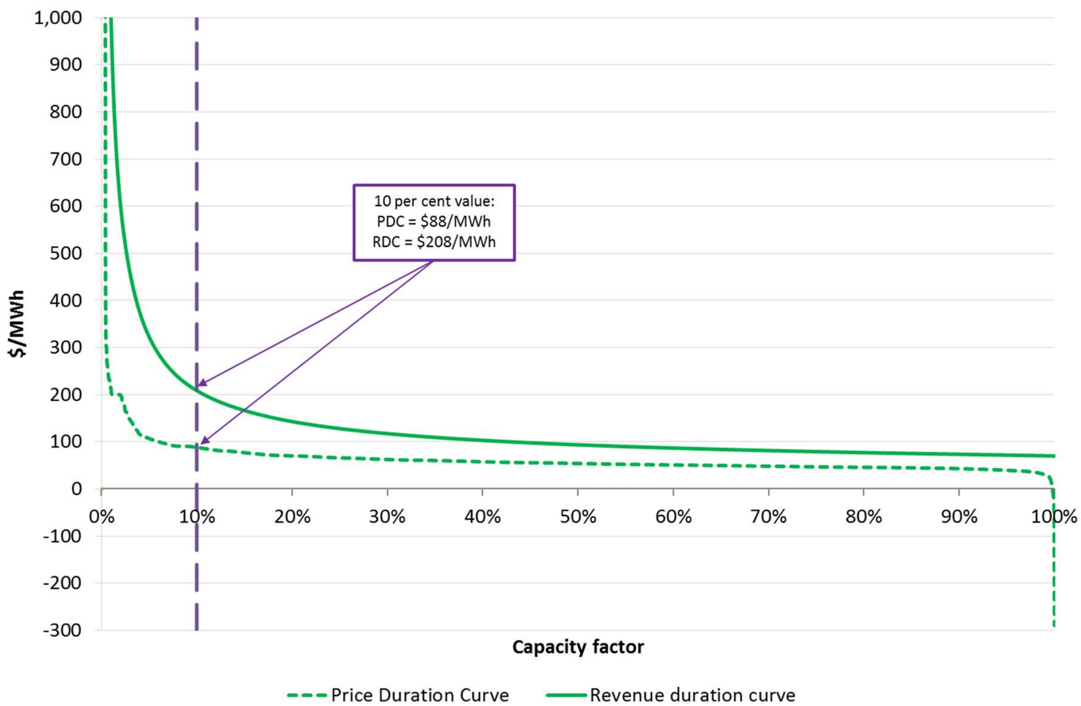
In calculating RDC, we take the following steps:

1. Take the RRP for each region for every 30 minute period.
2. Sort RRPs from highest to lowest value.
3. Calculated a running average of the descending price by interval. $(\frac{\text{Sum of descending prices}}{\text{The count of periods}})$
4. Plot running average across a zero to 100 per cent time base for the full financial year.

3.3 PDC and RDC together

Once calculated, we can illustrate the PDC and RDC together (Figure 7).

Figure 7 – PDC and RDC



The PDC and RDC should be read together. In the stylised example above, if a generator were to only operate during the 10 per cent of trading intervals when the spot price exceeded $88/MWh, its average earnings for that period would be priced at $208/MWh for each megawatt it produced. This is shown in Figure 7 at the vertical purple dashed line at 10 per cent.

3.3.1 Application to wind and solar technology

The RDC should be interpreted with caution. It should not be implied that all generation technologies are exposed to the full profile of this curve. For example, a high price/revenue period might not be co-incident with a period of high ambient energy (such as wind or solar) period. Therefore, we modified PDC and RDC for wind and solar energy.

3.3.1.1 Wind

We took the 2014-15 and 2017-18 wind generation data, with an arbitrary aggregate threshold above 10 MW in any particular region as a proxy for windiness in that region. Wind generation below 10 MW is taken as calm conditions and we exclude those prices from the data set. We then created the PDC and RDC from the adjusted data set.

Ultimately, the difference between the full RDC and the wind-adjusted RDC, for the years we selected, turned out to not be materially significant.

3.3.1.2 Solar

Solar energy is constrained by daylight hours. The NEM has a geographic range from southern Tasmania to far north Queensland. Given this, to maintain simplicity we needed to assume a central proxy for the NEM as a whole. We elected to use Mildura in northern Victoria as it is centrally located. Mildura has an average daylight time of about 51 per cent.

We took Mildura's sunrise and sunset times over an annual cycle, modelled and rounded them to the nearest half hour trading interval. The prices within these hours then formed the data set. We then created the PDC and RDC from this reduced data set.

4 Comparing LCOE and RDC

Illustrating the LCOE curve on the same graph as the PDC and RDC provides a high level visual indicator on the relationship between potential revenue and operating costs. If the RDC exceeds the LCOE at any point, then there may be an opportunity for a generator of that technology to fully recover its costs in that year.

A prospective generator will not enter the market unless it expects that it will fully recover its costs. In theory, if an opportunity for cost recovery remains sustained over time, this should form part of the market signal for the entry of the relevant technology type. If entry does not occur, there may be factors other than spot prices impeding new entry that warrant further analysis. Investors may also utilise other indicators in considering new entry that we don't account for (box 1).

Box 1 What drives investment?

Investment decisions are unlikely to be made based on spot outcomes in a single year alone. New entrants would consider other potential sources of revenue in establishing a business model, as well as more site-specific, detailed modelling of costs, risk and production. The projected trajectory of future prices will be influential for all generation assets.

Contracts for selling electricity, in particular, are important for new entrants. Establishing contracts insures against spot price volatility and plant reliability. Importantly for a new entrant, it provides future revenue certainty, which supports investment.

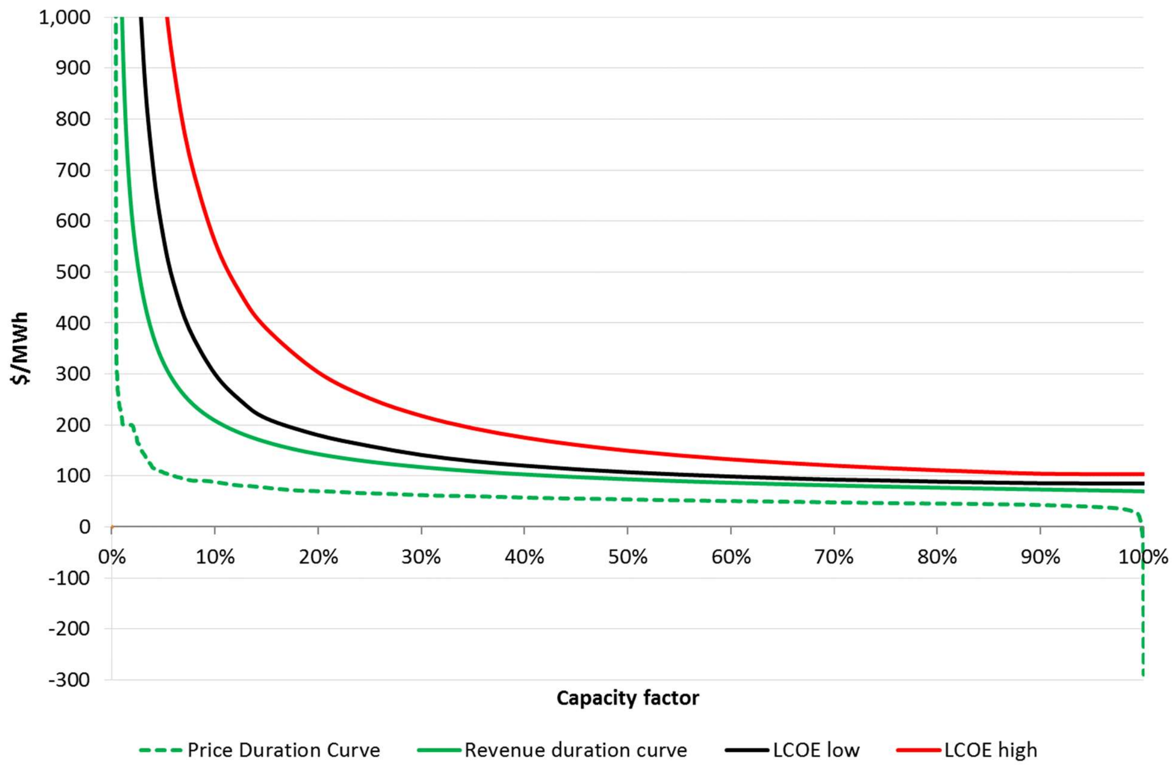
In addition, the provision of FCAS or other system services could provide alternative sources of revenue for a new entrant.

In the examples below, we have compared a range of LCOE curves for hypothetical technologies with a region's hypothetical PDC and RDC.

4.1 Example 1

In Figure 8, we see the high and low LCOE curves exceeding RDC for all potential capacity factors. As the LCOE curve for this technology is always above the RDC, this comparison indicates that, based on historical prices from that year, a new entrant of this technology could not recover its costs. Therefore, we would not expect to have seen new entry for this technology on the basis of spot prices alone.

Figure 8 - RDC lower than LCOE low curve

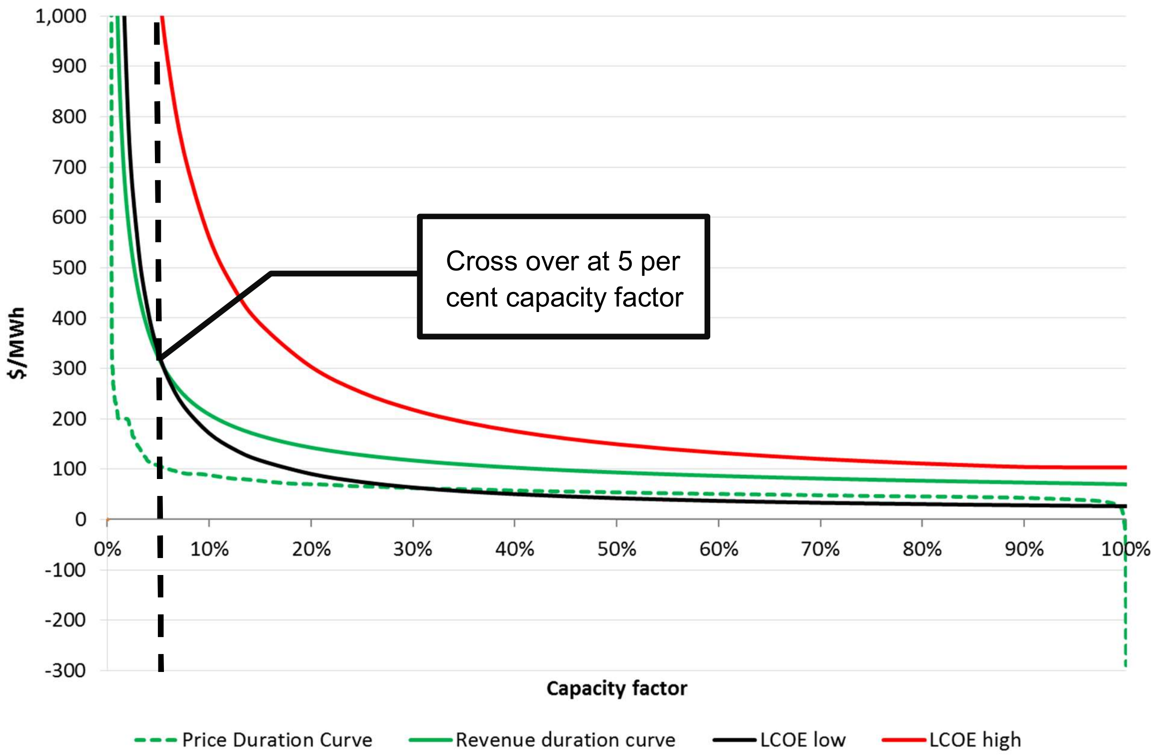


4.2 Example 2

In Figure 9, we see the RDC exceeding the low LCOE curve for most capacity factors, but remaining below the high LCOE curve for all. As the potential revenue exceeds some of the expected costs for that year, there exists a possibility for a new entrant of this technology to recover its costs. However, this result should be interpreted with caution. As the RDC has not exceeded the high LCOE curve, the possibility for cost recovery would likely exist only in favourable circumstances for that year and for that project

If this situation was sustained for several years in an efficient market, we might expect to see new entry for this technology. If there was no new entry, it would support a conclusion that there are other potential impediments requiring further investigation.

Figure 9 - RDC below LCOE high curve and above LCOE low

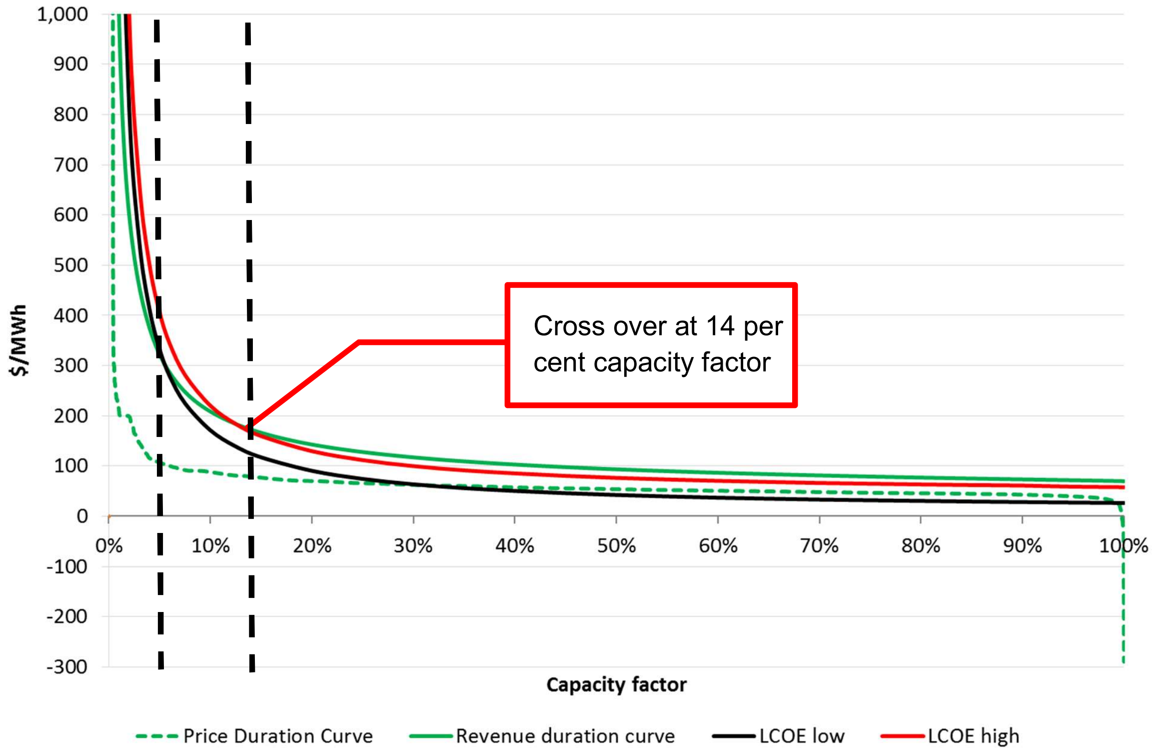


4.3 Example 3

In Figure 10, we see the RDC exceeding the high LCOE curve for capacity factors greater than about 14 per cent. As the potential revenue exceeds the expected costs for that year, there exists a possibility for a new entrant of this technology to recover its costs for that year.

If this situation was sustained, for several years, we might expect to see new entry for this technology. If there was no new entry, it would support a conclusion that there are other potential impediments requiring further investigation.

Figure 10 - RDC above LCOE high curve



5 Limitations

LCOE, PDC and RDC are simple, unsophisticated measures, designed to provide a high level indication at a glance. This has the benefit of making it accessible, transparent and comparable across different generation technology types. However, to avoid misinterpreting any results from this analysis, it is important to understand its various limitations:

- This analysis focuses on new entrant generators that only sell electricity into the spot market and the revenue they could earn from there. New entrants would consider other potential sources of revenue, such as ancillary services in establishing a business model. They would also need to consider risk management options, such as financial hedging, which would affect their revenues and bidding strategies.
- We also do not consider a portfolio approach to generation.
- We assume that a new entrant generator has the ability to choose bidding strategies that influence when it generates, allowing it to target certain production levels. In our working paper, we identified that this particularly affects intermittent generation like solar and wind.
- LCOE estimates exclude transmission constraints. Network congestion and constraints can affect a new entrant's ability to achieve the expected revenue indicated in the LCOE calculation.
- We exclude fuel transportation, transmission connection and other site specific or environmental costs from our estimations. These costs can vary from site to site, and it would require more detailed, site specific modelling to include in our estimates.
- For simplicity, LCOE estimates currently exclude a generator's operational start-up and shut down costs. These costs are proportional to the number of times a generator is started, and depend on a number of factors. While the number of times a generator starts can relate to its capacity factor, the relationship is not simple.
- We use the same WACC across all technologies. In reality, WACC is a unique parameter and will differ between companies and potentially between technology types. Our WACC values also do not vary over time, whereas a firm's WACC might change over time depending on a number of factors.
- The PDC and RDC do not consider the impact of new entrants on prices or costs. Typically, we would expect a new entrant to alter the shape of the PDC or RDC profile, reflecting their contribution. Large generators could have a significant effect on price, especially in smaller regions where an additional station would considerably add to existing capacity. For simplicity, our analysis assumes that the new entrant is too small to affect the price. This is because adjusting the curve to match the potential impact of a large new entrant would require more detailed market simulation. We may explore methods to resolve this limitation in future work.
- Spot prices can vary considerably between consecutive trading intervals. Minimum run times might force a generator, having turned on to receive a price above its costs, to endure periods of below cost prices or risk damaging equipment and incurring further

costs. If we seek to refine our estimations in the future, we may explore ways to address this.

- We have only calculated LCOE in 2017 Australian dollars. However, we are using prices from both 2014-15 and 2017-18, which means that the LCOE estimates we produce may not represent the levelised costs of new entrant generation in that year. This issue should not be significant for some technologies in the NEM, as they are mature and do not see pronounced cost and efficiency improvements from year to year.

  However, for some other technologies in the NEM, such as solar and wind, we have considered their cost trajectories in our analysis. We are using these comparisons to analyse price trends as they relate to investment at a high level. As long as we remain mindful of this in our analysis, it should not affect the overall change in trends we observe.

6 Findings

Below we discuss in further detail the results of our LCOE estimations.

6.1 Summary of results

For simplicity, we have summarised our analysis for the years 2014-15 and 2017-18 using simple colour coded bar charts (Figure 11 and Figure 12).

In these charts, the colour indicates the likelihood of cost recovery for a new entrant at different capacity factors. Red coloured sections represent capacity factors where a new entrant would be unlikely to recover its costs. Conversely, green coloured sections indicate capacity factors where a new entrant would be more likely to recover its costs (above our modelled high cost scenario). Yellow coloured sections show capacity factors in which a new entrant would potentially be able to recover its costs, in ideal conditions (above our low cost scenario). Grey sections are levels of production at capacity factors which are typically beyond the current capability observed for this technology type.

Figure 11 – Summary of results for 2014–15

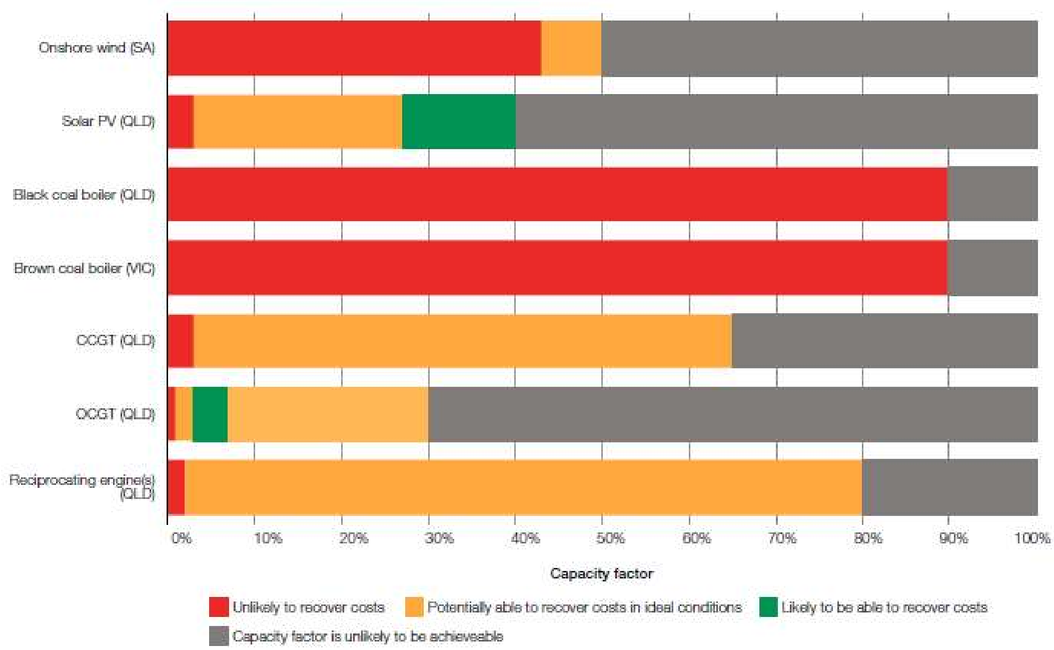
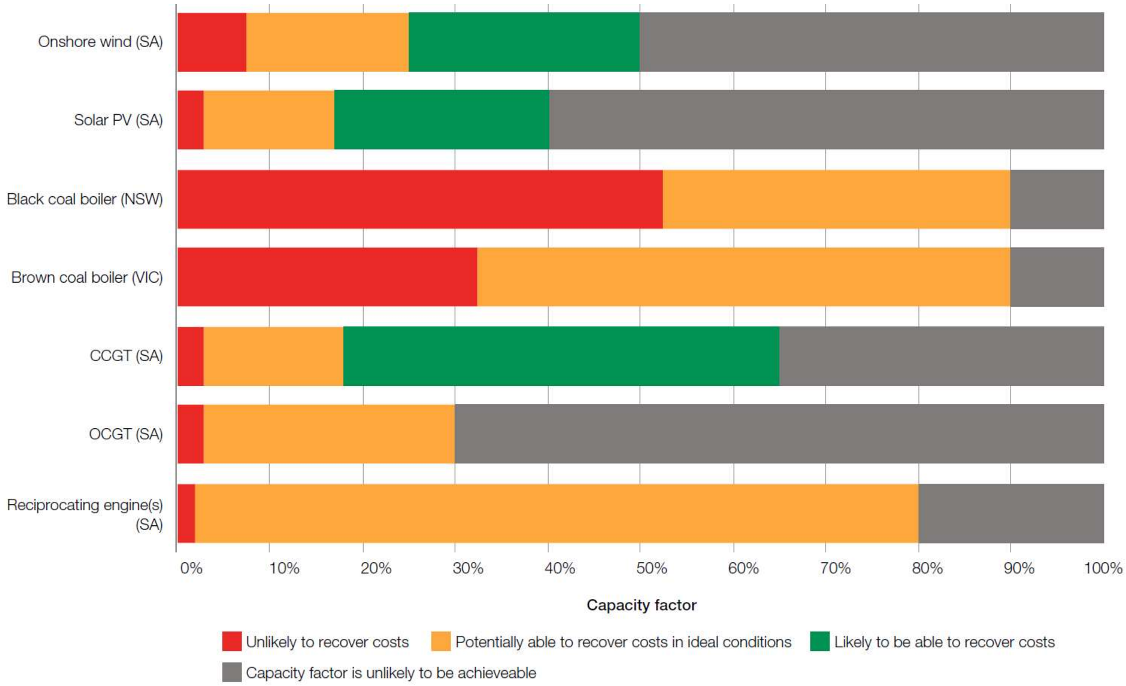


Figure 12 – Summary of results for 2017–18



6.2 Detailed LCOE curves by technology

In the following figures, to assist reading we have included dashed vertical lines indicating the first point of intersection between the highest RDC and the high and low LCOE curves. For clarity, we have also indicated in boxes what the capacity factor is at this point of cross over.

Read with the summary figures (Figure 11 and Figure 12), these additional marks highlight the capacity factors where the colour of the summary bar changes from red to yellow, or yellow to green.

6.2.1 Wind

Wind generators in the NEM currently operate at capacity factors of between 28 to 40 per cent. Based on our estimations, in order to have an opportunity to recover its costs:

- For the 2014-15 low cost scenario, in ideal conditions a new entrant wind generator would need to operate at a capacity factor of 43 per cent or greater. For the high cost scenario it would be unlikely to recover its costs at any level of operation.
- For the 2017-18 low cost scenario, in ideal conditions a new entrant wind generator would need to operate at a capacity factor of 8 per cent or greater. For the high cost scenario, it would need to operate at 25 per cent or greater.

Figure 13 – 2014-15 Wind

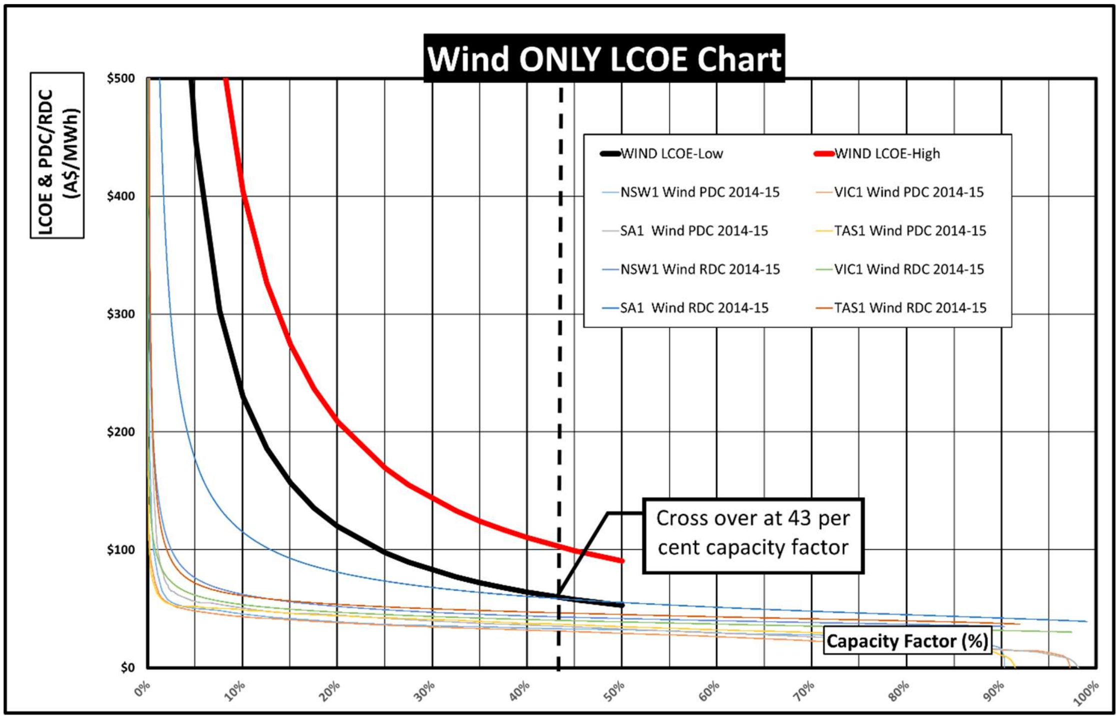
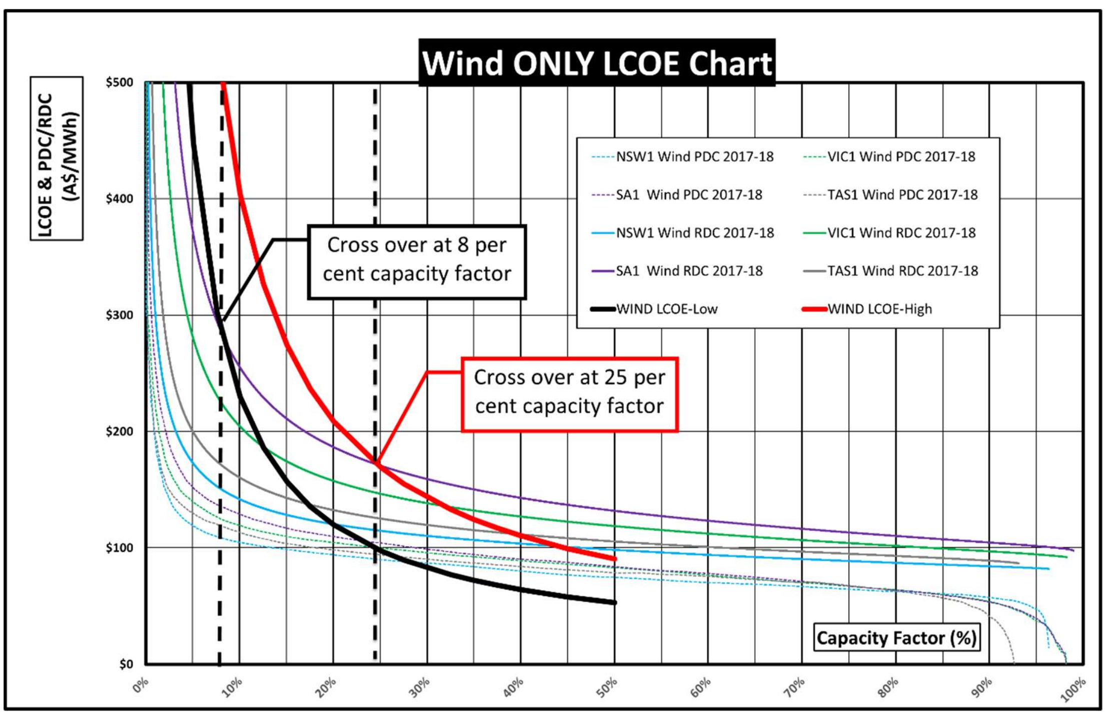


Figure 14 – 2017-18 Wind



6.2.2 Solar

Solar generators in the NEM currently operate at capacity factors of between 12 to 28 per cent. In order to have an opportunity to recover its costs:

- For the 2014-15 low cost scenario, in ideal conditions a new entrant solar generator would need to operate at a capacity factor of about 3 per cent or greater. For the high cost scenario, it would need to operate at 27 per cent or greater in Queensland. As we use estimates in 2017 Australian dollars, this result may not accurately represent a new entrants levelised costs for that year.[16]
- For the 2017-18 low cost scenario, in ideal conditions a new entrant solar generator would need to operate at a capacity factor of 3 per cent or greater. For the high cost scenario, it would need to operate at 17 per cent or greater.

Figure 15 – 2014-15 Solar

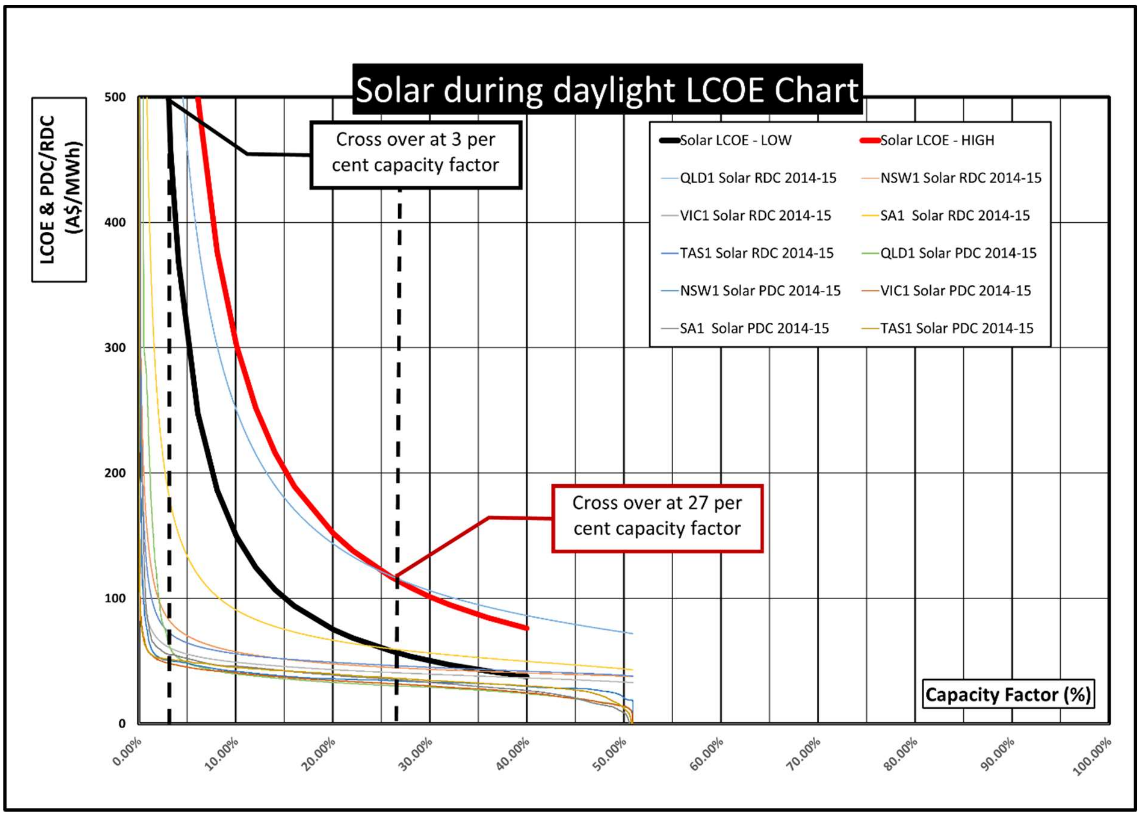
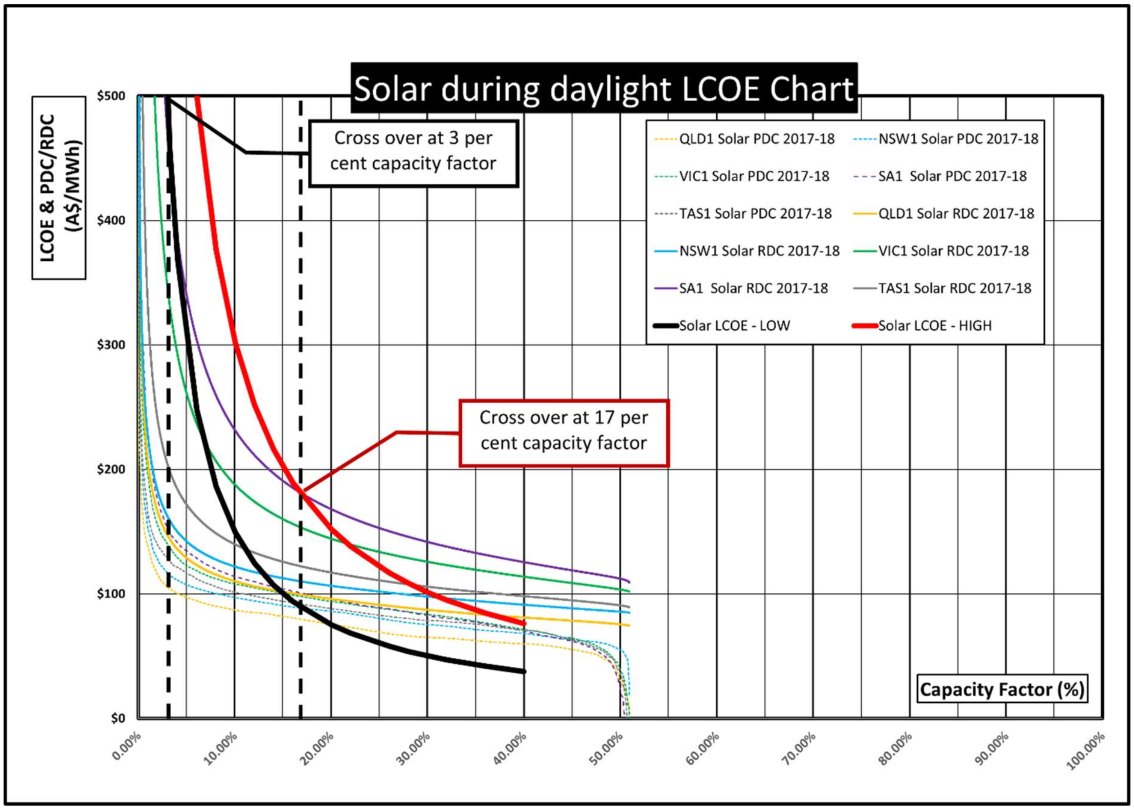


Figure 16 – 2017-18 Solar

16 For further discussion of this results, see section 5.2 of the *Wholesale electricity market performance report 2018*.



6.2.3 CCGT

CCGT generators in the NEM currently operate at capacity factors of between 20 to 65 per cent. In order to have an opportunity to recover its costs:

- For the 2014-15 low cost scenario, in ideal conditions a new entrant CCGT generator would need to operate at a capacity factor of 3 per cent or greater. For the high cost scenario, it would be unlikely to recover its costs for all levels of operation.
- For the 2017-18 low cost scenario, in ideal conditions a new entrant CCGT generator would need to operate at a capacity factor of 3 per cent or greater. For the high cost scenario, it would need to operate at 18 per cent or greater in South Australia and at 52 per cent or greater in Victoria. It would be unlikely to recover its costs in other NEM regions in the high cost scenario.

Figure 17 – 2014-15 CCGT

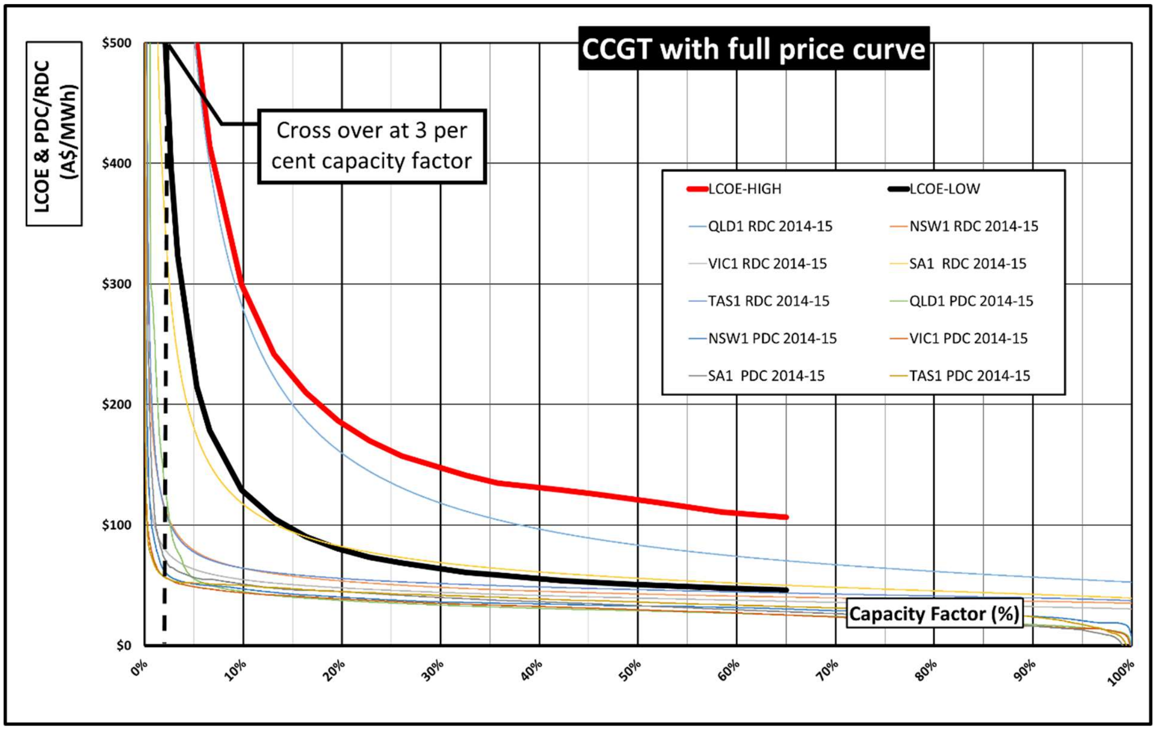
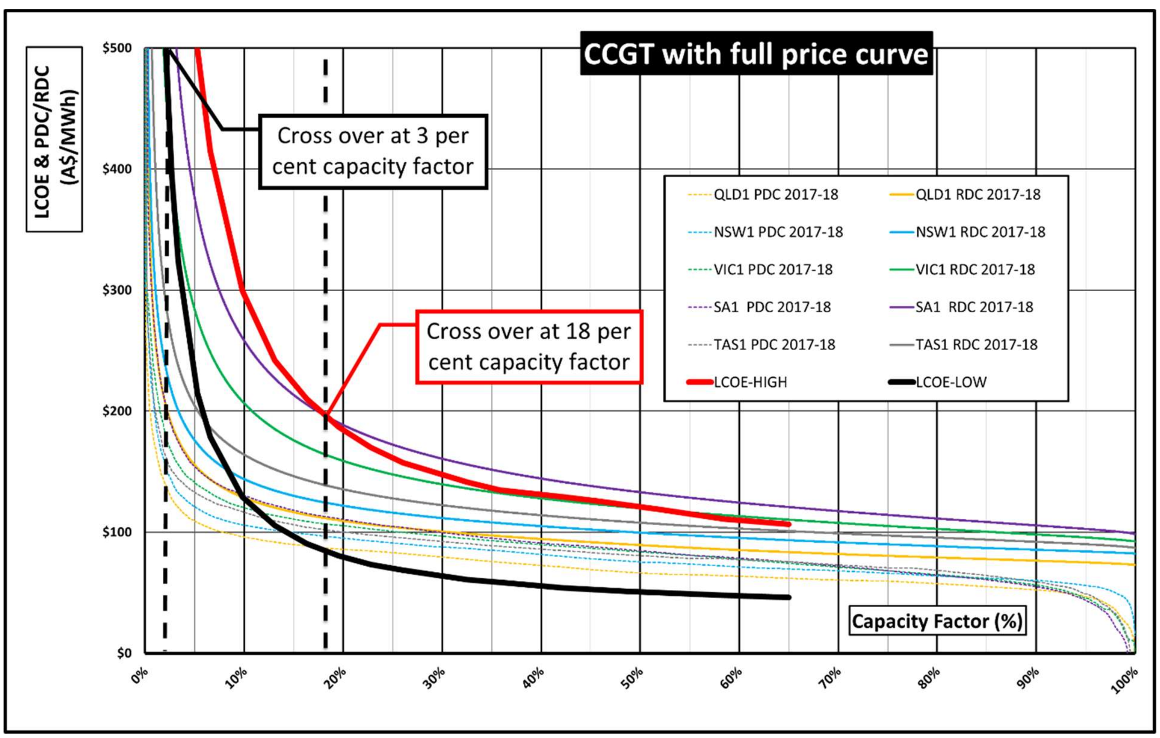


Figure 18 – 2017-18 CCGT



6.2.4 OCGT

OCGT generators in the NEM currently operate at capacity factors of between five to 25 per cent. In order to have an opportunity to recover its costs:

- For the 2014-15 low cost scenario, in ideal conditions a new entrant OCGT generator would need to operate at a capacity factor of 1 per cent or greater. For the high cost scenario, it would need to operate between capacity factors of between 3 and 7 per cent in Queensland. It would be unlikely to recover its costs in other NEM regions in the high cost scenario.
- For the 2017-18 low cost scenario, in ideal conditions a new entrant OCGT generator would need to operate at a capacity factor of 3 per cent or greater. For the high cost scenario, it would be unlikely to recover its costs at any level of production.

Figure 19 – 2014-15 OCGT

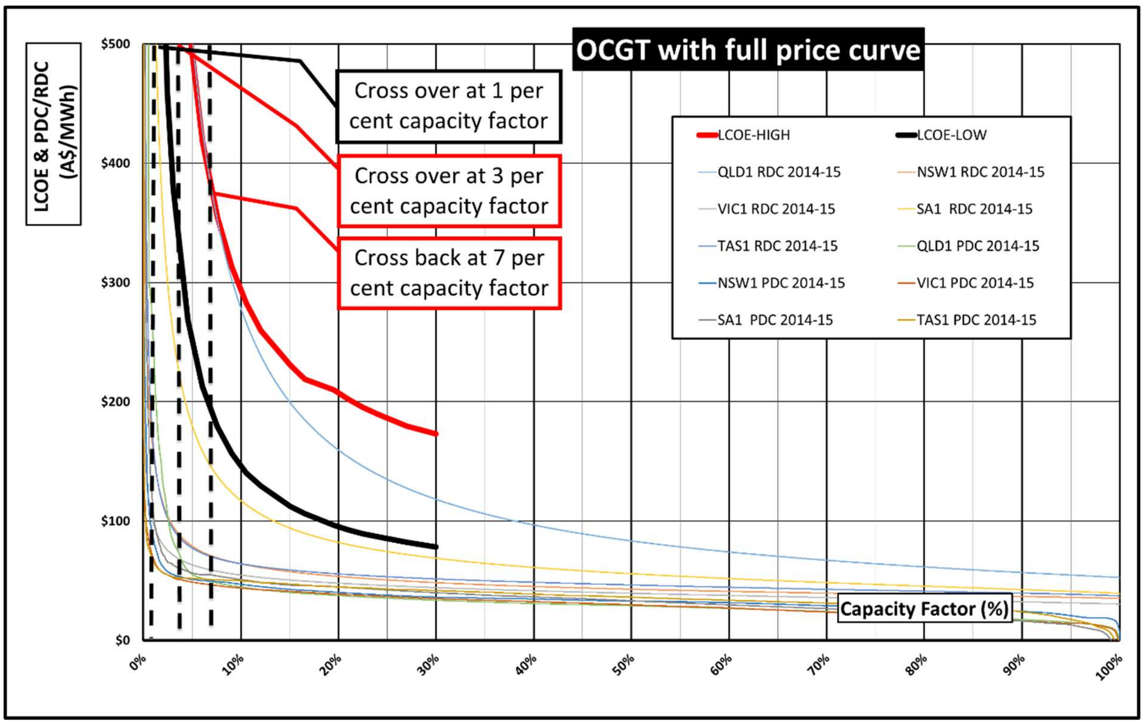
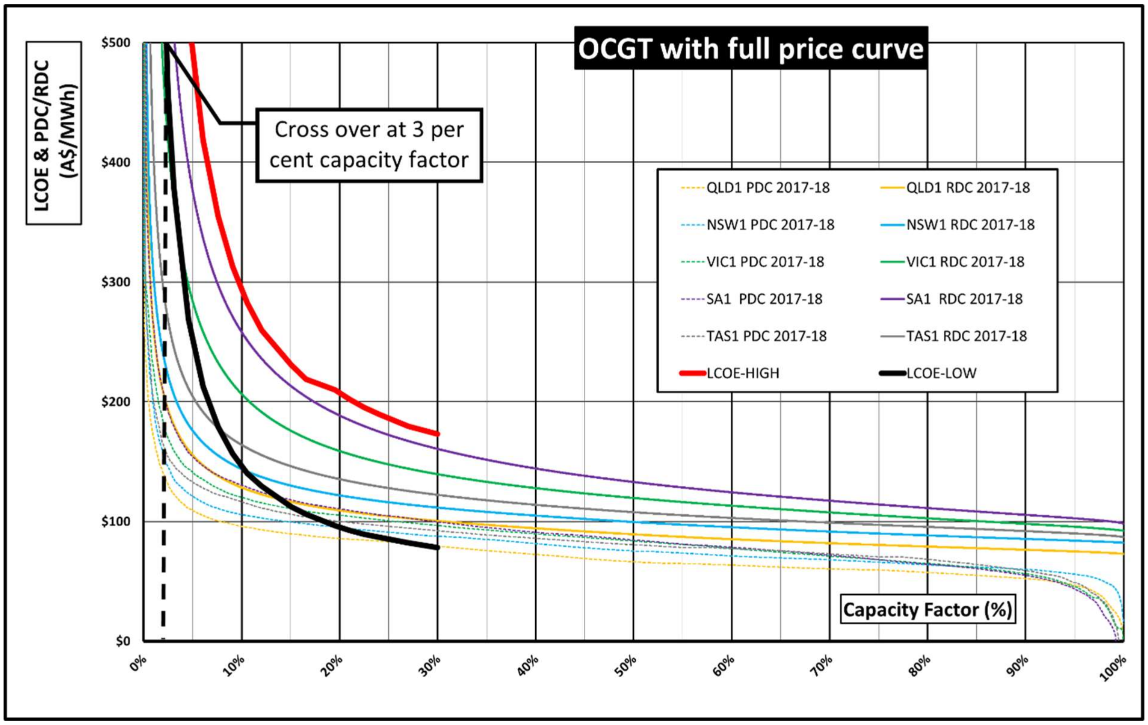


Figure 20 – 2017-18 OCGT



6.2.5 Black coal

Black coal generators in the NEM currently operate at capacity factors of between 60 to 90 per cent. In order to have an opportunity to recover its costs:

- For 2014-15, a new entrant black coal generator would be unlikely to recover its costs at any level of production.
- For the 2017-18 low cost scenario, in ideal conditions a new entrant black coal generator would need to operate at a capacity factor of 52 per cent or greater. For the high cost scenario it would be unlikely to recover its costs at any level of production.

Figure 21 – 2014-15 Black coal

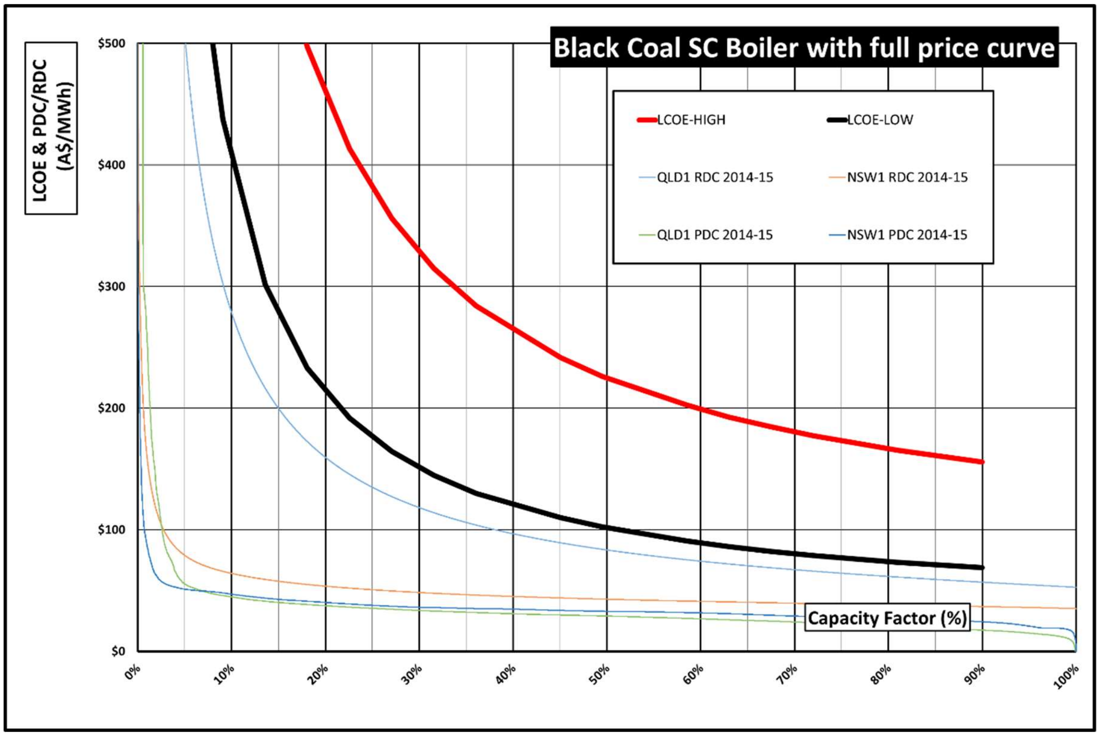
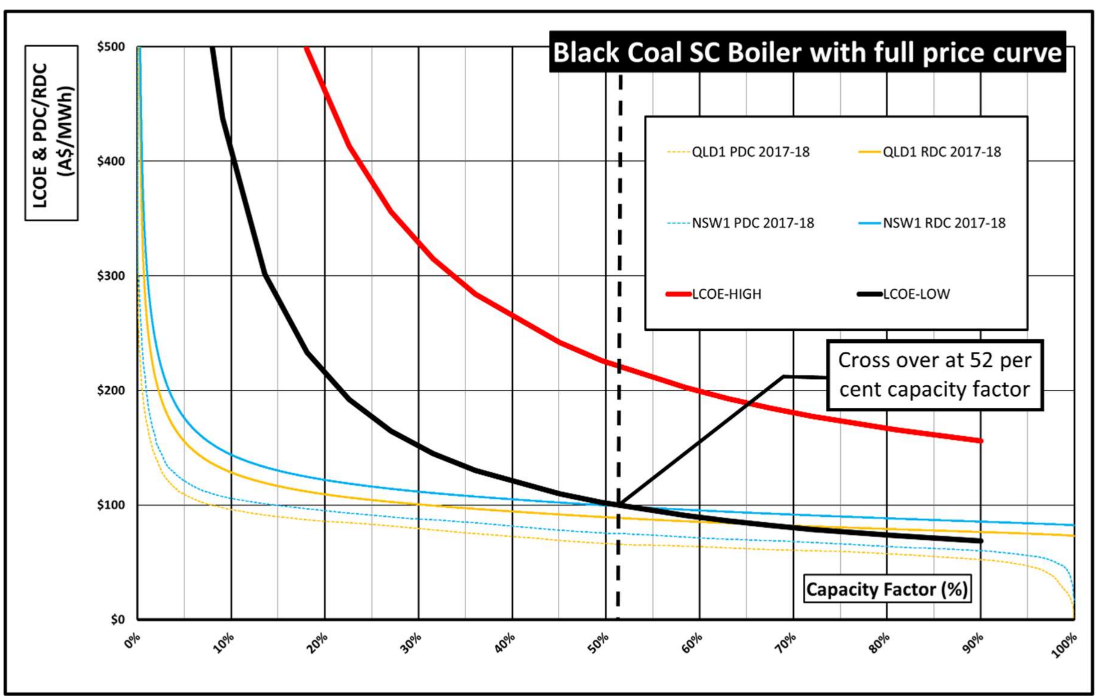


Figure 22 – 2017-18 Black coal



6.2.6 Brown coal

Brown coal generators in the NEM currently operate at capacity factors of between 45 to 80 per cent. In order to have an opportunity to recover its costs:

- For 2014-15, a new entrant brown coal generator would be unlikely to recover its costs at any level of production.
- For the 2017-18 low cost scenario, in ideal conditions a new entrant brown coal generator would need to operate at a capacity factor of 32 per cent or greater. For the high cost scenario it would be unlikely to recover its costs at any level of production.

Figure 23 – 2014-15 Brown coal

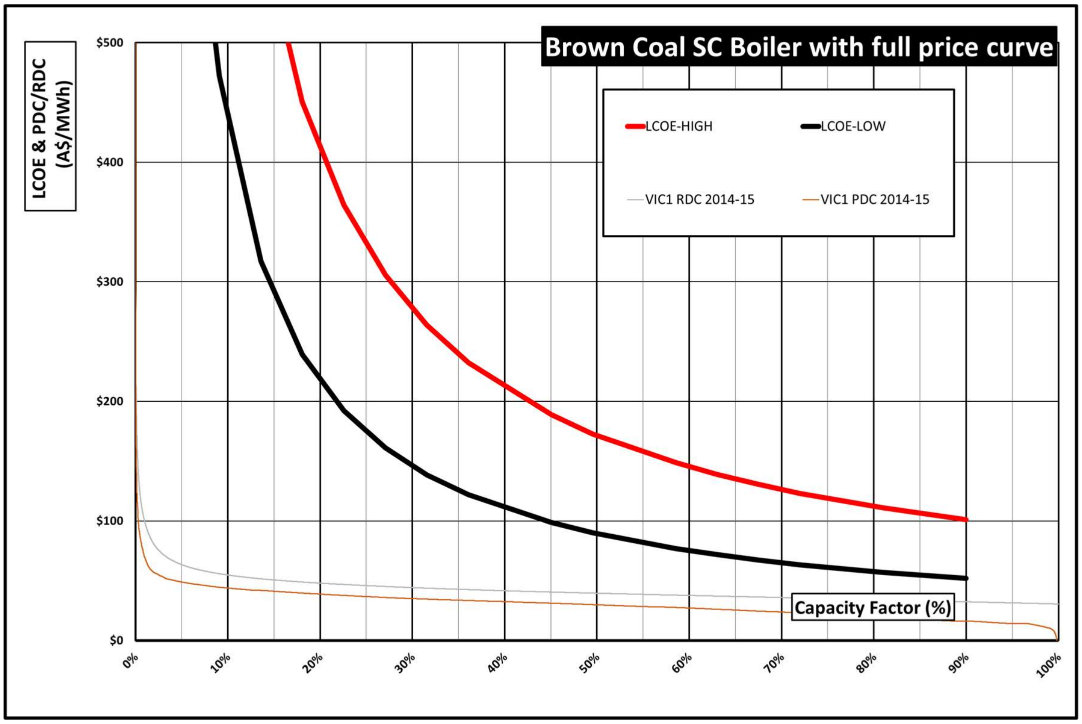
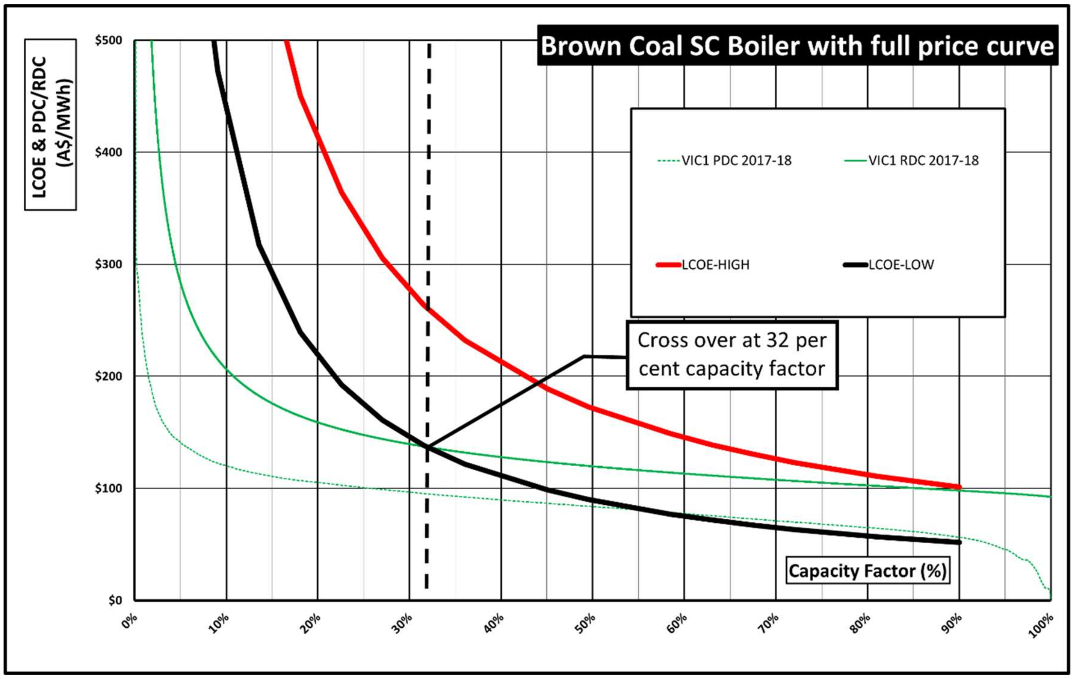


Figure 24 – 2017-18 Brown coal



6.2.7 RICE

RICE generators in the NEM currently operate at capacity factors below 5 per cent, however this does not reflect a technology constraint. In order to have an opportunity to recover its costs:

- For the 2014-15 low cost scenario, in ideal conditions a new entrant RICE generator would need to operate at a capacity factor of 2 per cent or greater. For the high cost scenario it would be unlikely to recover its costs at any level of production.
- For the 2017-18 low cost scenario, in ideal conditions a new entrant RICE generator would need to operate at a capacity factor of 2 per cent or greater. For the high cost scenario it would be unlikely to recover its costs at any level of production.

Figure 25 – 2014-15 Reciprocating internal combustion engines

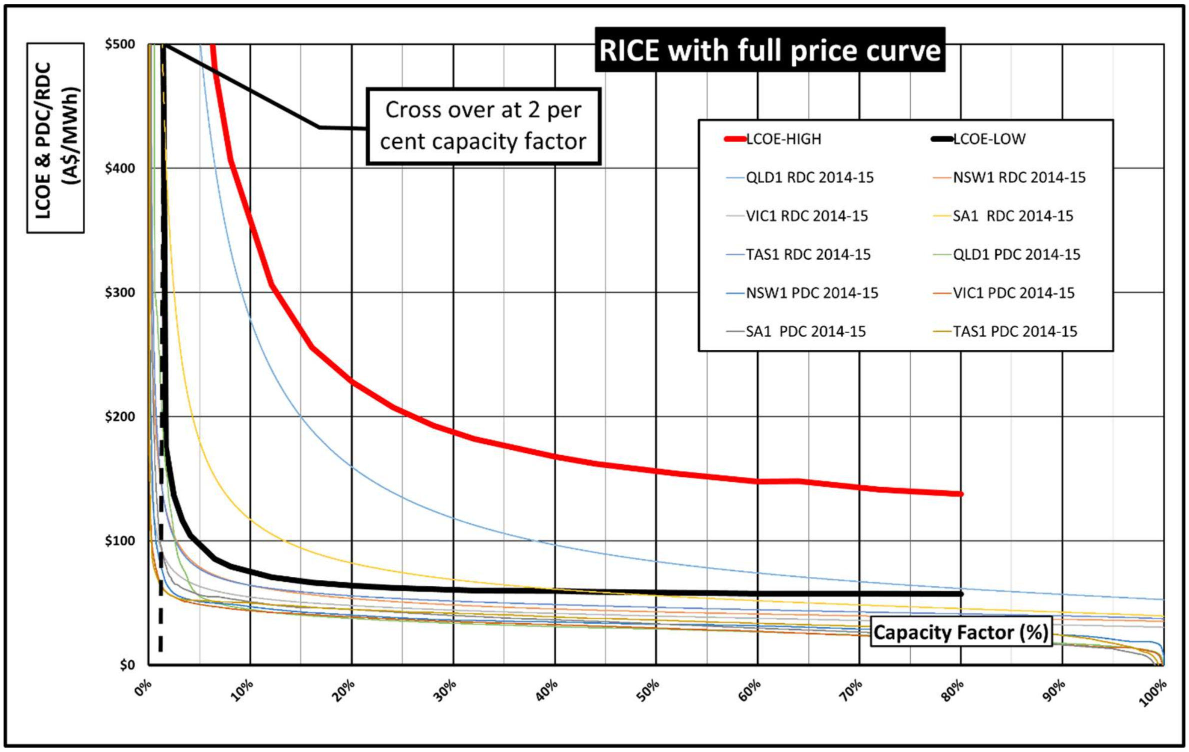
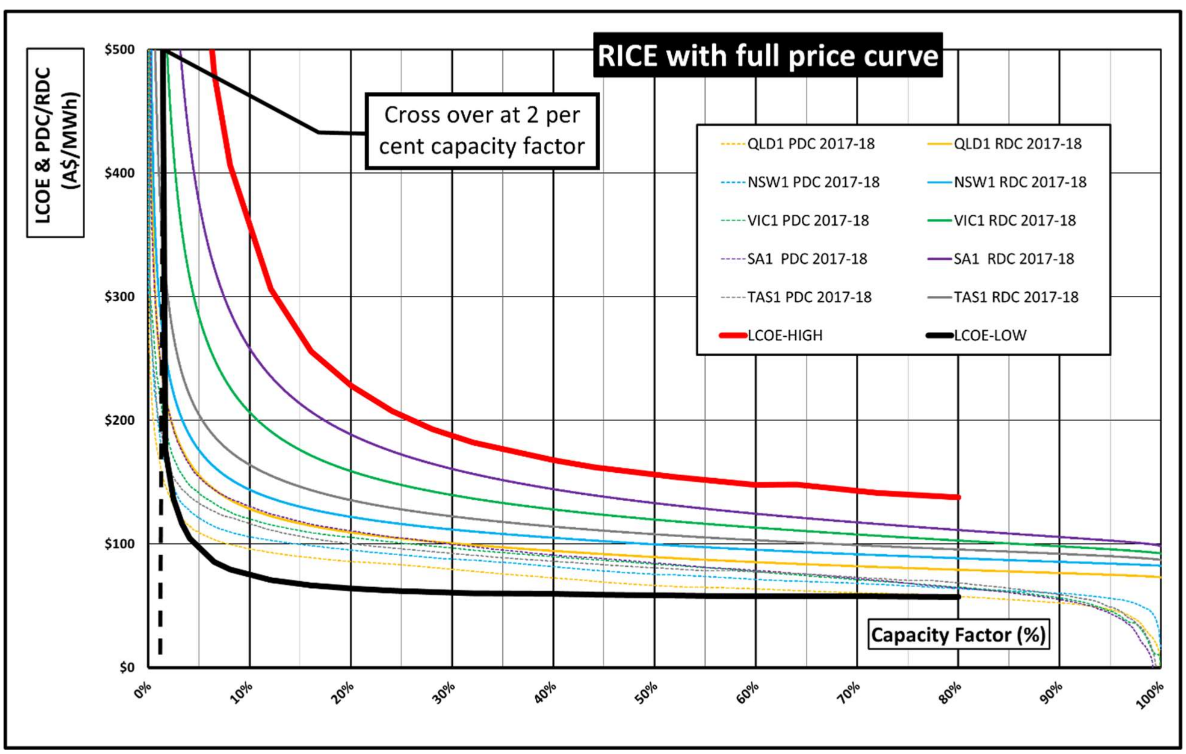


Figure 26 – 2017-18 Reciprocating internal combustion engines



Appendix A: Summary of comments on Staff working paper

We received three comments to our Staff working paper. Two were formal and non-confidential and have been placed on our website. One was informal and confidential. Of these comments, two were provided by generator participants, and one was from a consumer group.

Stakeholder	Comment	Response
EnergyAustralia	LCOE analysis needs to take into account plant limitations, such as minimum run times and start costs.	We have not included start costs or minimum run times at this time for simplicity. We may revisit this in future analysis.
	It is important to consider how to apply LCOE across different forms of generation, especially intermittent technologies and storage	We agree that different technologies require different consideration. We have not included storage technologies for the 2018 performance report.
	Intermittent generation technologies have no control over when they generate. The coincidence of intermittent production to the wholesale price needs to be considered.	We agree. We have constructed separate PDC/RDC for wind and solar that reflect the prices faced by those generators at times of production.
MEU	The AER should develop LCOE for each type of existing generation in each region of the NEM to measure market power.	For the 2018 performance report, we are focusing on the relationship between prices and new entry.
	If prices are high due to the exercise of market power, this forms a barrier to entry and new entrants will assess the market as not commercially sound.	We will be careful to consider any results of LCOE analysis in conjunction with the results of other analysis and tools we will use.
Confidential	The levelised cost of storage (LCOS) may provide a more useful point of reference for intermittent technologies, given many proposed projects incorporate some firming capacity.	We have not included storage technologies for the 2018 performance report. We will consider the best way to incorporate the cost of storage for future analysis.

	High price events generally do not occur in sequence, meaning generators may endure periods of below cost pricing. Discounting the RDC relative to historical spot price outcomes may address this.	For the 2018 performance report, we have not done this. However, we acknowledge this point as a limitation of the analysis to explore in the future.

Appendix B: LCOE References

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