LCOE and LCOS modelling approach, limitations and results

Wholesale electricity market performance report 2022

December 2022

AUSTRALIAN
ENERGY
REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Tel: 1300 585 165

AER reference: #14,751,253

Contents

Shortened forms

Shortened Form	Extended Form
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage System
CCGT	Combined cycle gas turbine
CPI	Consumer price index
EOH	Equivalent operating hours
EPC	Engineering procurement and construction
FOM	Fixed operation and maintenance costs
HELE	High efficiency low emissions
LCOE	Levelised cost of energy
LCOS	Levelised cost of storage
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
PHES	Pumped hydro energy storage
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 electricity 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 2022* (the performance report) we used levelised cost of energy (LCOE) and levelised cost of storage (LCOS) estimates for this assessment of price trends.[1] These estimates formed part of an indicator that was considered alongside a broad range of other factors in assessing the effectiveness of competition and efficiency of the market.

In an efficient, competitive market, with free entry and exit, it is expected that prices 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.

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.

1 AER, *Wholesale electricity market performance report 2022*, December 2022.

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.

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

1 We compared LCOE and price for a range of generation technologies

An LCOE and price comparison compares a new 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 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 2022 performance report, we estimated LCOE for the following technologies:

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

LCOE is a common estimation technique used for comparing the lifetime costs of different generation technologies. As in 2020, 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 do?

For our analysis, we reviewed a range of publicly available data on new entrant costs, collating results to produce high (worst case) and low (best case) estimate scenarios for each technology type (full references to our sources are in Appendix A: LCOE References). Using a number of assumptions, we then calculated the LCOE across a range of capacity factors, rather than assigning a single value to a technology.

In most cases, we compared LCOE to potential revenue in each NEM region for the 2020-21 and 2021-22 financial years. In cases where there is a practical limitation to the entry of a particular technology (for example, the unavailability of black 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. Also, we do not include regional cost differences for construction, transmission, land values etc. in our estimations.

Importantly, LCOE does not include storage technologies (such as batteries). For these technologies, we calculated LCOS estimates (Chapter 2).

1.2 Methodology

To calculate LCOE, we used the following algorithm (Figure 1.1 LCOE algorithm).[3]

Figure 1.1 LCOE algorithm

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

Where:

r = discount rate (percent)
n = life of the asset (years)
I_t = Investment expenditure in the year t
Mt = Operations and maintenance expenditure in the year t
Ft = Fuel expenditure in the year t
Et = Electricity generation in the year t

1.2.1 Calculation assumptions

We used the following assumptions in calculating LCOE:

- 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.[4] The capital costs perimeter is taken to be the boundary of the power station, and includes capital costs to EPC,

---

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

4 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.

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 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.
  - Land or other site specific expenses.
  - Exit costs including any site remediation or scrap values of retired plant and equipment.
  - Costs are averages and are therefore not adjusted for site specific or region-specific factors.
  - Forced outage rates are assumed. These are defined as breakdown or other outage periods when operation might otherwise have occurred.

1.3 Inputs

Generators face variable and fixed costs and LCOE includes estimates for both. There are also several other important input parameters into the LCOE calculation such as:

- capacity factor
- NPV
- Weighted Average Cost of Capital (WACC)
- heat rates
- fuel costs
- CPI
- lead times for construction
- payment milestones

1.3.1 Capacity factor

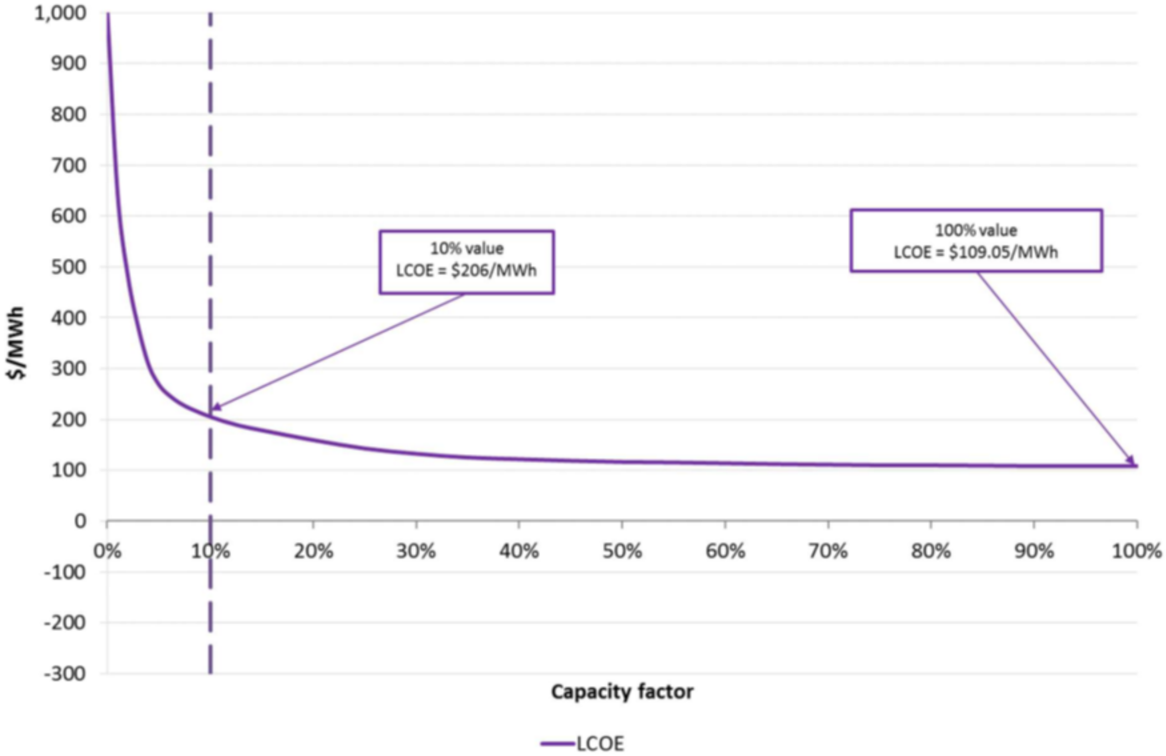
The capacity factor is an important parameter in calculating LCOE values. The capacity factor is the amount of energy produced by a generator as a proportion of its maximum possible production over a given period (Figure 1.2 Capacity factor formula).

Figure 1.2 Capacity factor formula

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

This parameter is significant in the LCOE calculation as the 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 (Figure 1.3 LCOE Curve).

Figure 1.3 LCOE Curve



In our example, for a generator producing 10% of the year, its levelised costs are $206 per MWh. Similarly, if the same generator produces all the energy it can for the entire year, its levelised costs equate to the value of the LCOE curve at 100%, or around $109 per MWh.

When calculating capacity factors, 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. As such we use nameplate rating in the calculation, for simplicity.

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. For our analysis, we have truncated our LCOE curves at the following capacity factors:[5]

- Onshore wind - 45%
- Offshore wind - 48%
- Solar - 51%
- CCGT - 65%
- OCGT - 25%
- RICE - 75%
- Black coal - 90%

These values reflect the typical operational capacity factors we observed for existing units in the NEM.

1.3.2 Considerations in NPV cash flow calculation

We consider the following in our NPV calculation:

- Currency is nominally in 2022 Australian dollars.
- We use the WACC as the discount rate.

  Capital construction costs are to go from a greenfields 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 many years.
- We assume a generator'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 loan, 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.

---

[5] 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.

- Variable operation and maintenance (VOM) costs are all costs that are zero if the generator doesn't operate, excluding fuel costs. We increase these annually in line with the CPI assumption.
- For natural gas and black coal fuel costs, we have used an upper and lower bound of recent prices.
- Major overhaul costs return the machine to 'as new' condition in terms of residual life. They are expensive, might typically cost 20% to 30% 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.
- While we consider the economic life of the assets we do not model any exit costs.

1.3.3 Weighted average cost of capital

WACC is a critical input because the NPV calculation uses it to discount all future cash flows. As we cannot know these values for a "levelised" company, we have made some bounded assumptions in understanding the WACC range.[6]

For our purposes in estimating new entrant LCOE, we will use a WACC range of between 7% and 9.5% for all technologies.

1.3.4 Heat rate

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.

A heat rate is 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 (Figure 1.4 Heat rate and efficiency formulas).

Figure 1.4 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 2022 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 between 8.0 and 9.5 GJ per MWh (38% to 45% efficiency).[7]

---

6 AER, Draft 2022 Rate of Return Instrument, June 2022

7 Catalogue of CHP Technologies, US Environmental Protection Agency, Combined Heat and Power Partnership (Sept 2017).

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

1.3.5 Fuel costs

In calculating fuel costs, we consider black coal (QLD and NSW), brown coal (Victoria) and natural gas as input costs for their respective technologies (Figure 1.4 Heat rate and efficiency formulas).

Figure 1.5 Fuel cost formula

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

We use upper and lower values from AEMO's ISP only, rather than trying to predict forward commodity prices over the next 30 years.

1.3.6 CPI

We examined CPI data from the Australian Bureau of Statistics, but we acknowledge that some costs are not related to the Australian economy alone.[8] Therefore, for our estimations, we use a 2% to 3% range for CPI inflation. We also acknowledge that the current CPI inflation rate is above our 2-3% range, however our CPI indexation factor feeds calculations for the next 30 years. We note that since the RBA introduced it's 2-3% inflation target in 1990, the inflation rate has not remained above the target range for more than a few consecutive quarters.

1.3.7 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.

1.3.8 Lead time for construction and payment milestones

We have used AEMO's data for assumptions of construction lead time by technology.[9] However, from that data the spend profile during the construction period is unclear. 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% 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.

---

[8] ABS, Consumer Price Index, Australia

[9] AEMO, 2022 ISP Input and Assumptions workbook, v1,Jul 22.

1.4 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 weather conditions

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).[10]

For the 2020-21 and 2021-22 financial years, we calculate a separate PDC and RDC for each

NEM region:

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

We also construct the RDC by region for solar and wind technologies, to reflect the prices those intermittent technologies are exposed to, which are weather and time of day dependent.

We discuss this further in section Application to wind and solar technology

---

[10] AER, Wholesale electricity market performance monitoring - Staff working paper on 2018 approach to LCOE analysis, 15 June 2018.

1.4.1 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.

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. This data set then forms the basis of the RDC.

1.4.2 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.

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

$$\left(\frac{\text{Sum of descending prices}}{\text{The count of periods}}\right)$$

4. Plot running average across a 0% to 100% time base for the full financial year.

1.4.3 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 coincident with a period of intermittent renewable generation. Therefore, the PDC and RDC for wind and solar energy are constructed differently:

- For wind, we took the 2020-21 and 2021-22 wind generation data from a site in each NEM region and applied an arbitrary threshold of output in excess of 5% of the nameplate rating as a proxy for windiness in that region. Wind generation below this threshold is taken as calm conditions and those prices are excluded from the data set. We then created the RDC from the adjusted data set.
- Solar energy is obviously constrained to daylight hours. As for wind, a solar site in each NEM region was selected and a 5% of nameplate threshold was applied as a proxy for sunshine being available (i.e. not overcast daytime). Where the threshold was not exceeded the prices were excluded from the data set. We then created the RDC from the adjusted data set.

1.5 Comparing LCOE and RDC

Comparing LCOE and RDC acts a high level indicator of the relationship between potential revenue and operating costs.

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 1.1: What drives investment?).

Box 1.1: 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.

We modelled both high and low LCOE estimates. If the RDC exceeds the high LCOE estimate at any point, then is likely an opportunity for a generator of that technology to fully recover its costs in that year. If the RDC only exceeds the low LCOE estimate, then a generator of that technology may only be able to recover its costs in that year in ideal circumstances. If the RDC does not exceed either LCOE estimate, then it is unlikely that prices are at a level for a generator of that technology to recover its costs in that year.

1.6 Limitations

LCOE and RDC comparisons are simple, unsophisticated measures, designed to provide a high level indicator that is accessible, transparent and comparable across different generation technology types. However, to avoid misinterpreting any results from this analysis, it is important to understand its limitations:

- This analysis focuses on new entrant generators that only sell electricity into the spot market and the revenue they might earn doing so. New entrants would consider other potential sources of revenue, such as ancillary services and risk management options in establishing a business model.
- We do not consider a portfolio approach to generation.
- We assume that a new entrant generator has the ability to choose strategies that influence when it generates, allowing it to target certain production levels.
- LCOE estimates exclude transmission constraints.
- 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.
- We use the same WACC across all technologies. 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.
- The RDC construction does not consider the impact of new entrants on prices or costs. New large generators could have a significant effect on price, especially in smaller regions where any new capacity might considerably add to existing capacity. Therefore, for simplicity, our analysis assumes that the new entrant is too small to affect the price.
- 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 operating equipment in a non-preferred way thereby incurring further costs.
- We have only calculated LCOE in 2022 Australian dollars using prices from both 2020-21 and 2021-22, which means that the LCOE estimates we produce may not represent the levelised costs of new entrant generation in a future year.

  This issue should not be as significant for mature technologies (such as coal) as for newer technologies in the NEM (such as large-scale solar). 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 observed trends.

1.7 Findings

The following section presents the results of our analysis. First, summarised as presented in the 2022 performance report. Then, we provide the full detailed results (section Detailed LCOE curves by technology).

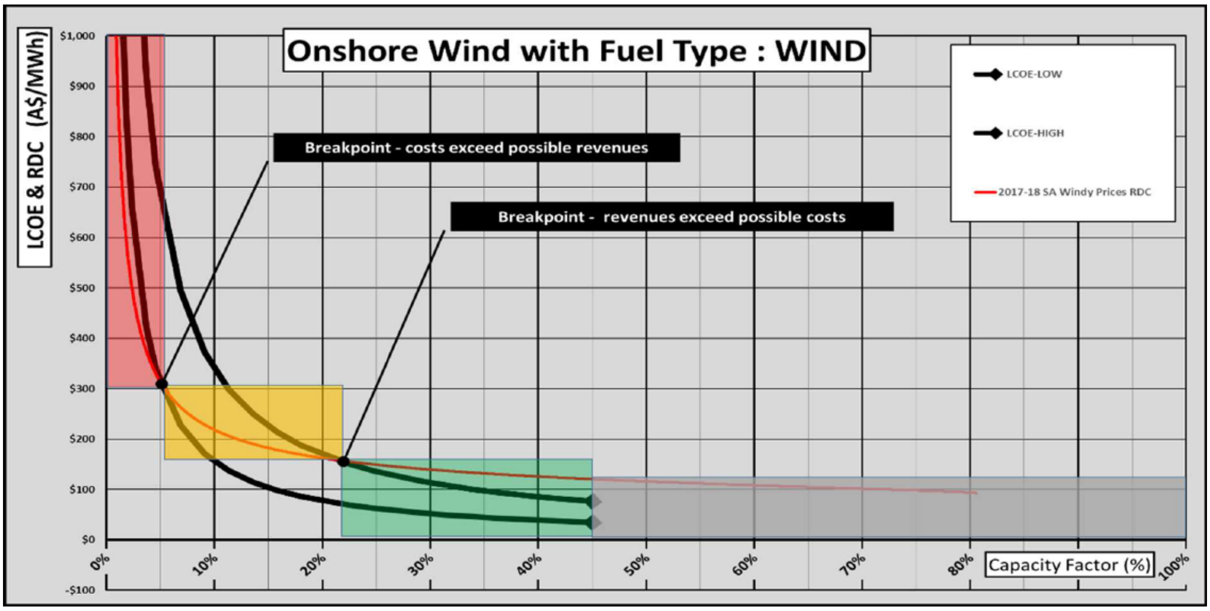
- Green coloured sections indicate capacity factors where a new entrant would be more likely to recover its costs (above our modelled high cost scenario).
- Yellow coloured sections show capacity factors in which a new entrant would potentially be able to recover its costs, in ideal conditions (above our low cost but below our high cost scenario).
- Red coloured sections represent capacity factors where a new entrant would be unlikely to recover its costs.
- Grey sections are levels of production at capacity factors which are typically beyond those currently observed for this technology type.

1.7.1 Summarised results

For simplicity, we have summarised our analysis for the years 2020-2021 and 2021-22 using colour-coded bar charts. In the summary charts, the colour shown indicates the likelihood of cost recovery for a new entrant at different capacity factors (Figure 1.6):

- 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 but below our high cost scenario).
- Red coloured sections represent capacity factors where a new entrant would be unlikely to recover its costs.
- Grey sections are levels of production at capacity factors which are typically beyond those currently observed for this technology type.

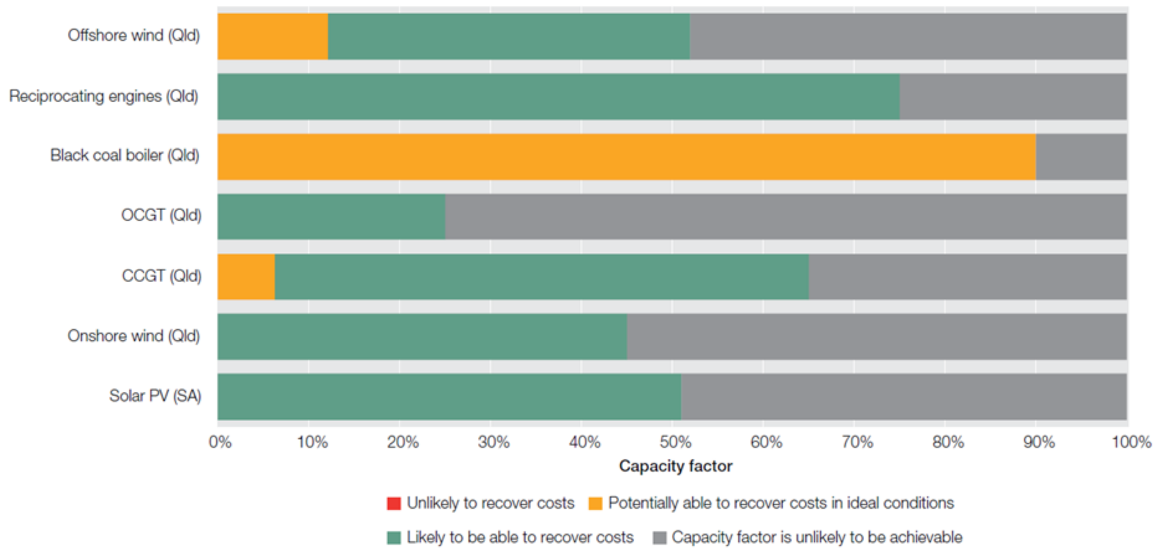
Figure 1.6 Interpreting the summarised results



For most technologies, our analysis suggest that prices are sufficient for a new entrant to recover their costs in both 2020-21 and 2021-22 (Figure 1.7 Summary of results for 2020–21 (Figure 7.2 in main report) and Figure 1.8 Summary of results for 2021–22 (Figure 7.3 in main report)).

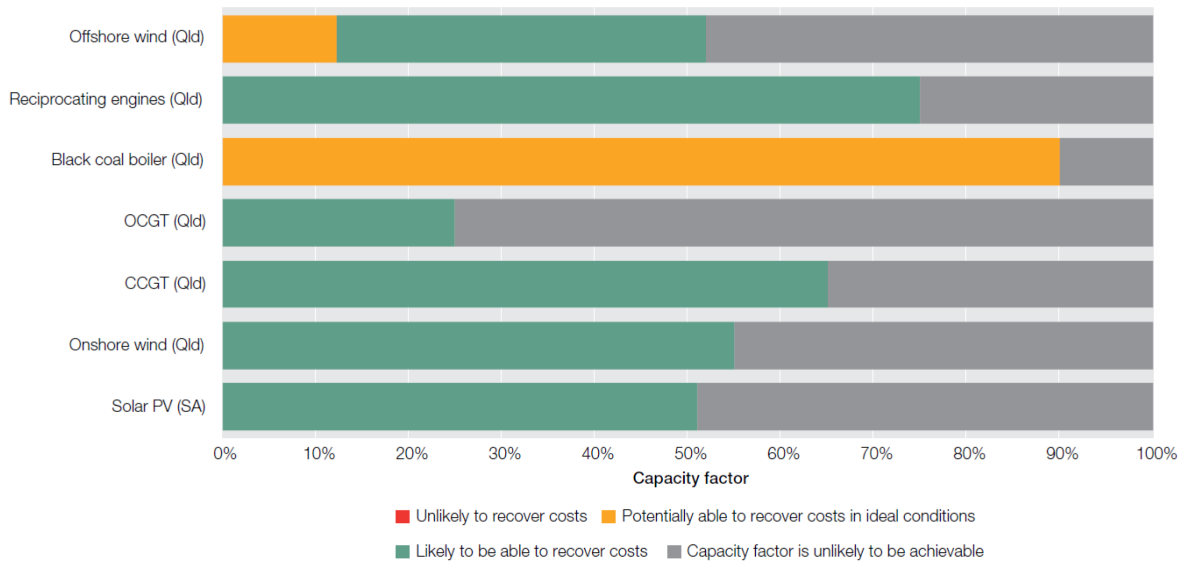
While black coal generators do not have as strong a signal, a new entrant may be able to recover costs in ideal circumstances.

Figure 1.7 Summary of results for 2020–21 (Figure 7.2 in main report)



Note: CCGT: combined cycle gas turbines. OCGT: open-cycle gas turbines.

Figure 1.8 Summary of results for 2021–22 (Figure 7.3 in main report)



Note: CCGT: combined cycle gas turbines. OCGT: open-cycle gas turbines.

1.7.2 Detailed LCOE curves by technology

In the following figures, we present the raw outputs of our analysis, comparing high and low LCOE curves for a technology against the RDC for each region. Where the fuel is natural gas, the gas price in each state was used to construct the summary bar charts in section 1.7.1. We used an average for the curves below.

Wind

With no effective fuel cost, price signals for wind generation investment are very positive. Wind generators in the NEM currently operate at capacity factors up to about 45%. Based on our estimations, in order to have an opportunity to recover its costs:

- For the 2020-2021 low cost scenario a new entrant wind generator would recover its costs at all levels of production. For the high cost scenario, it would need to operate at a capacity factor greater than 6% (Figure 1.9 Onshore Wind 2020-21)
- For the 2021-22 low cost scenario, high prices in Queensland meant that in ideal conditions a new entrant onshore wind generator would recover its costs at all levels of production (Figure 1.10 2021-22 Onshore Wind). For the high cost scenario it would need to operate at a capacity factor greater than 1%.

Figure 1.9 Onshore Wind 2020-21

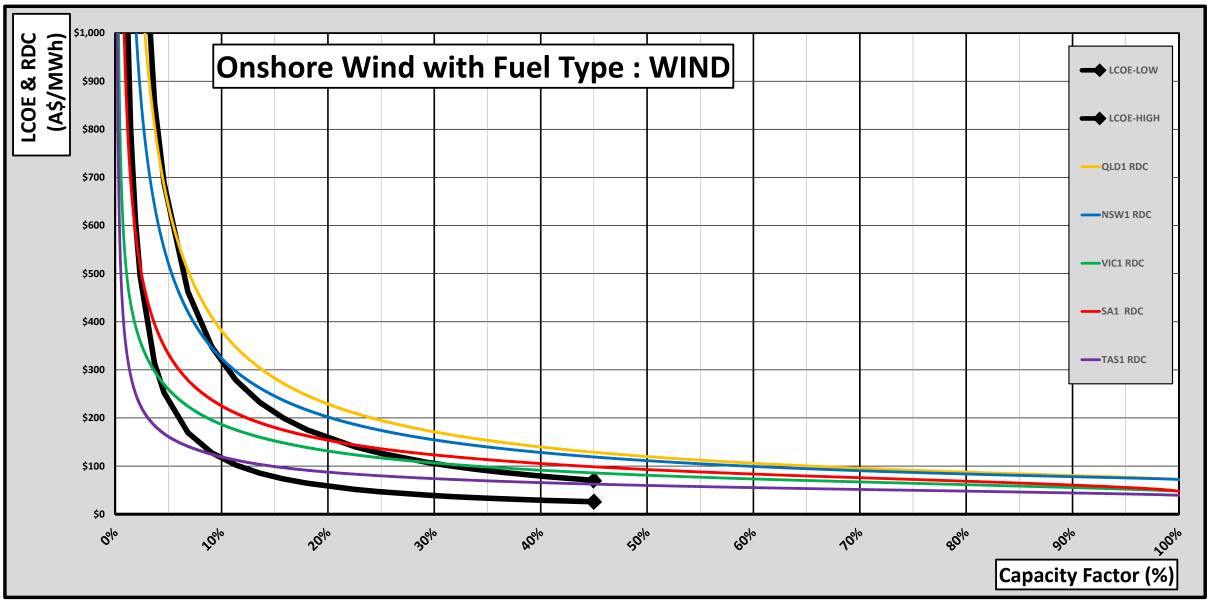
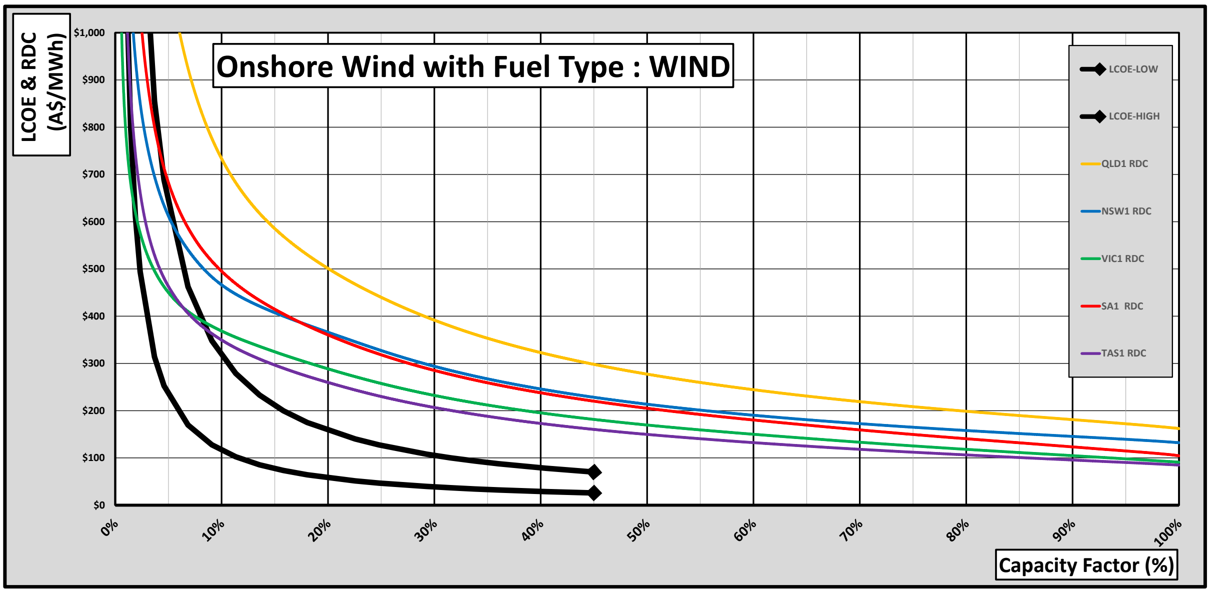


Figure 1.10 2021-22 Onshore Wind

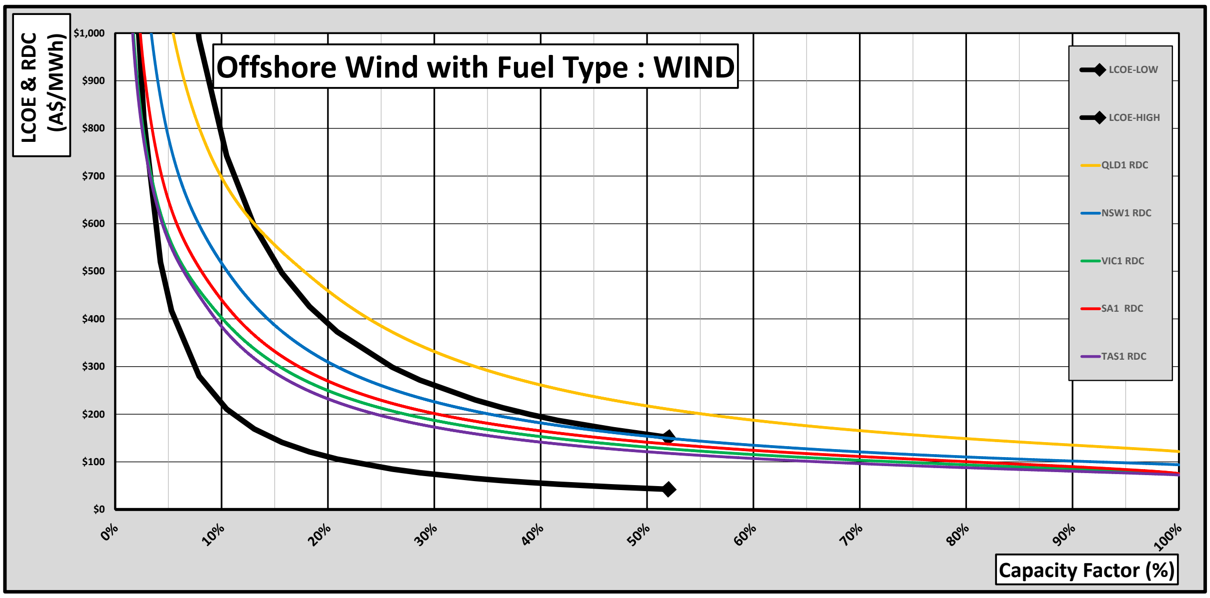


Offshore wind

Offshore wind farms are larger and can enjoy windier geography than onshore wind. There are currently no onshore wind farms connected to the NEM, but globally have been recorded achieving capacity factors of up to 51%.[11] Based on our estimates, in order for an offshore wind generator to recover its costs:

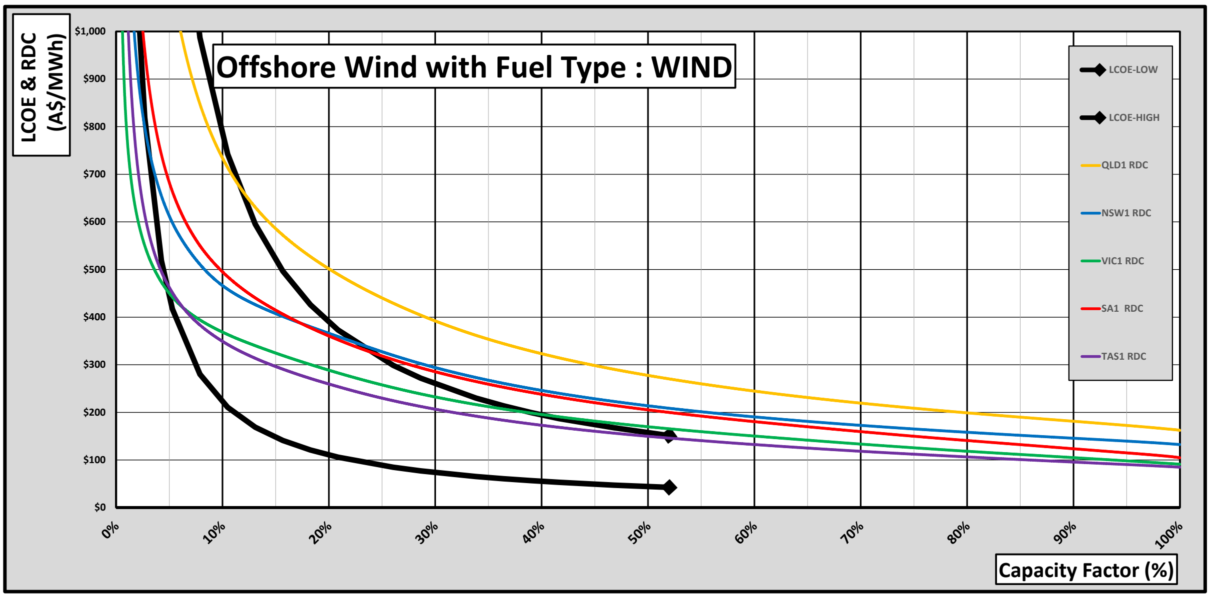
- For the 2020-21 low cost scenario a new entrant offshore wind generator would recover costs operating at any capacity (Figure 1.11 2020-21 Offshore Wind). For the high cost scenario, it would need to operate at a capacity greater than 12%.
- For the 2021-22 low cost scenario a new entrant offshore wind generator would recover its costs operating at any capacity (Figure 1.12 2021-22 Offshore Wind). For the high cost scenario, it would need to operate at a capacity factor greater than 11%.

Figure 1.11 2020-21 Offshore Wind



11 University of Michigan, Wind Energy Factsheet, 2022

Figure 1.12 2021-22 Offshore Wind



Solar

With no effective fuel cost, price signals for investment in solar generation were positive. Solar generators in the NEM currently operate at average capacity factors ranging from 17-58%. In order to have an opportunity to recover its costs:

- For the 2020-21 low cost scenario, a new entrant solar generator would recover costs at all levels of output (Figure 1.13 2020-21 Solar). The same was true of our high cost scenario.
- For the 2021-22 low cost scenario a new entrant solar plant would be able to recover it's costs at all level's of output (Figure 1.14 2021-22 Solar). The same was true of our high cost scenario.

Figure 1.13 2020-21 Solar

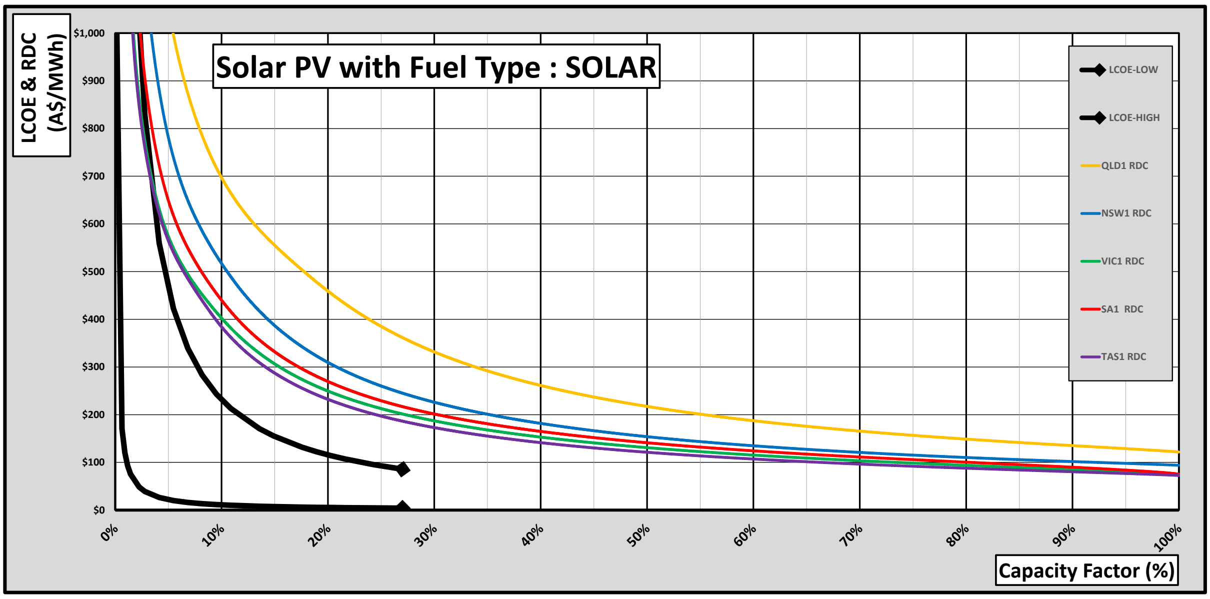
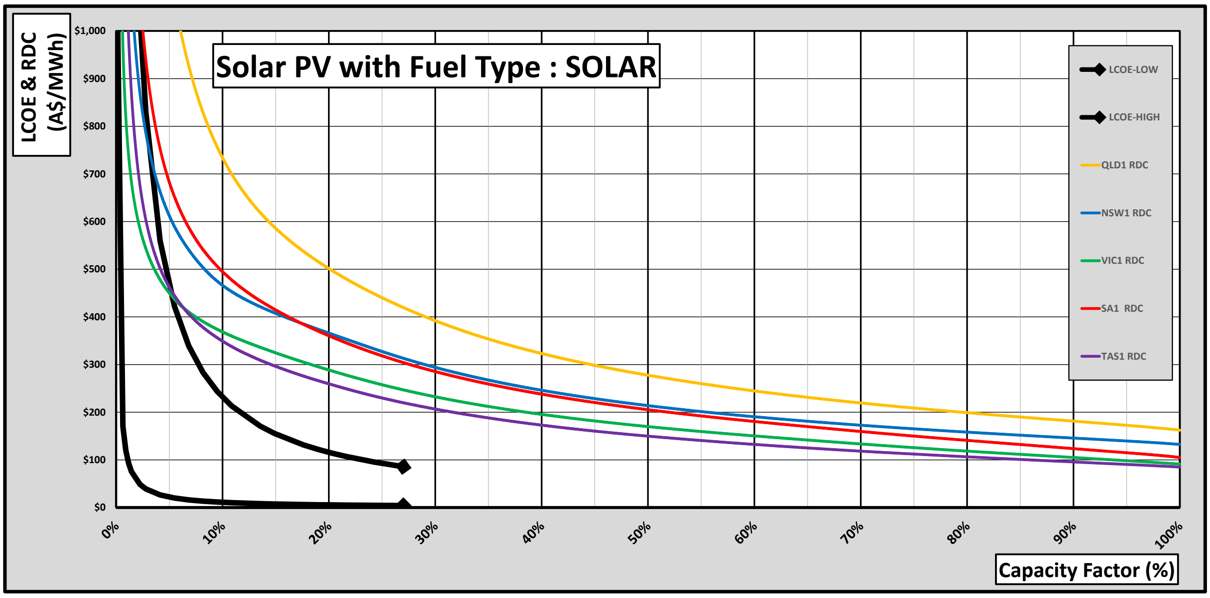


Figure 1.14 2021-22 Solar



CCGT

Increasing gas prices saw results from 2021-22 differ from 2020-21, however high prices in some regions still provide positive signals for investment. CCGTs in the NEM operate at capacity factors of between 10% and 65%. In order to have an opportunity to recover its costs:

- For the 2020-21 low cost scenario, a new entrant CCGT would recover its costs operating all levels of production (Figure 1.15 2020-21 CCGT). In our high cost scenario, it would recover costs by generating at a capacity factor greater than 6%.
- For 2021-22 low cost scenario, a new entrant CCGT would recover its costs operating all levels of production (Figure 1.16 2021-22 CCGT). For our high cost scenario, which included Gas at $13GJ (above the Australian government cap of $12/GJ)[12]. It would need to operate at a capacity factor greater than 6.5%

---

12 ABC, Coal and Gas Prices to be capped as national cabinet strikes deal, December 2022

Figure 1.15 2020-21 CCGT

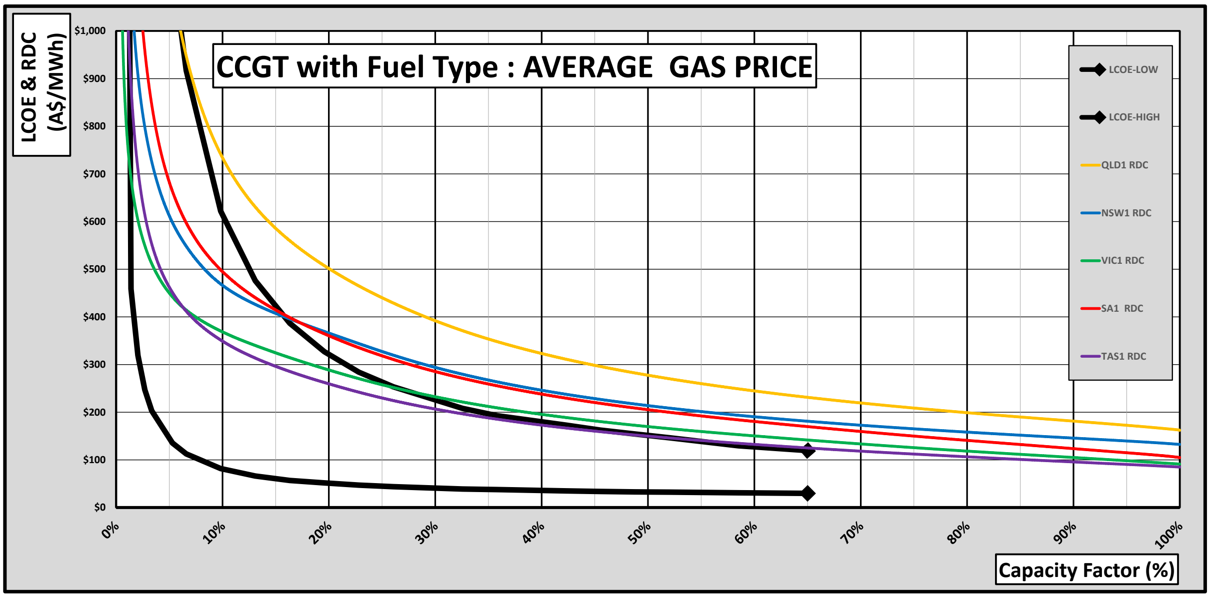
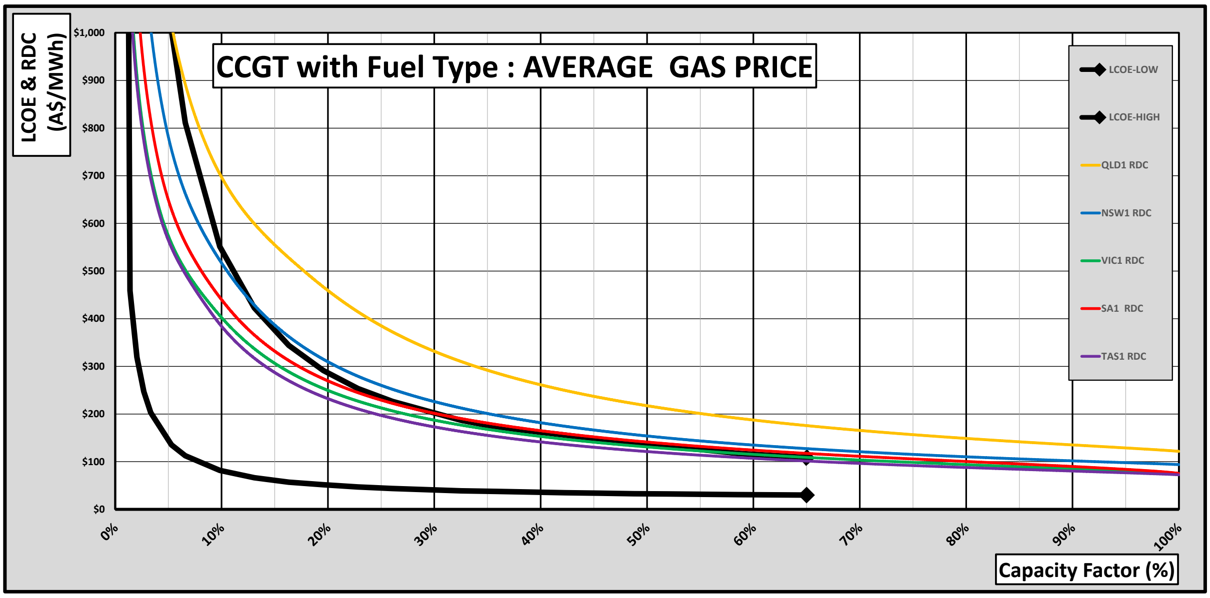


Figure 1.16 2021-22 CCGT



OCGT

Increasing gas prices saw results from 2021-22 differ from 2020-21, however high prices in some regions still provide positive signals for investment. OCGTs in the NEM operate at capacity factors of between 2% and 25%. In order to have an opportunity to recover its costs:

- For the 2020-21 low cost scenario a new entrant CCGT generator would have an opportunity to recover it's costs at all levels of production, the same is true of our high cost scenario (Figure 1.17 OCGT 2020-21).

- Fort the 2021-22 low cost scenario, a ne new entrant CCGT generator would have an opportunity to recover its costs at all levels of production. The same was true of our high cost scenario Figure 1.18 OCGT 2021-22)

Figure 1.17 OCGT 2020-21

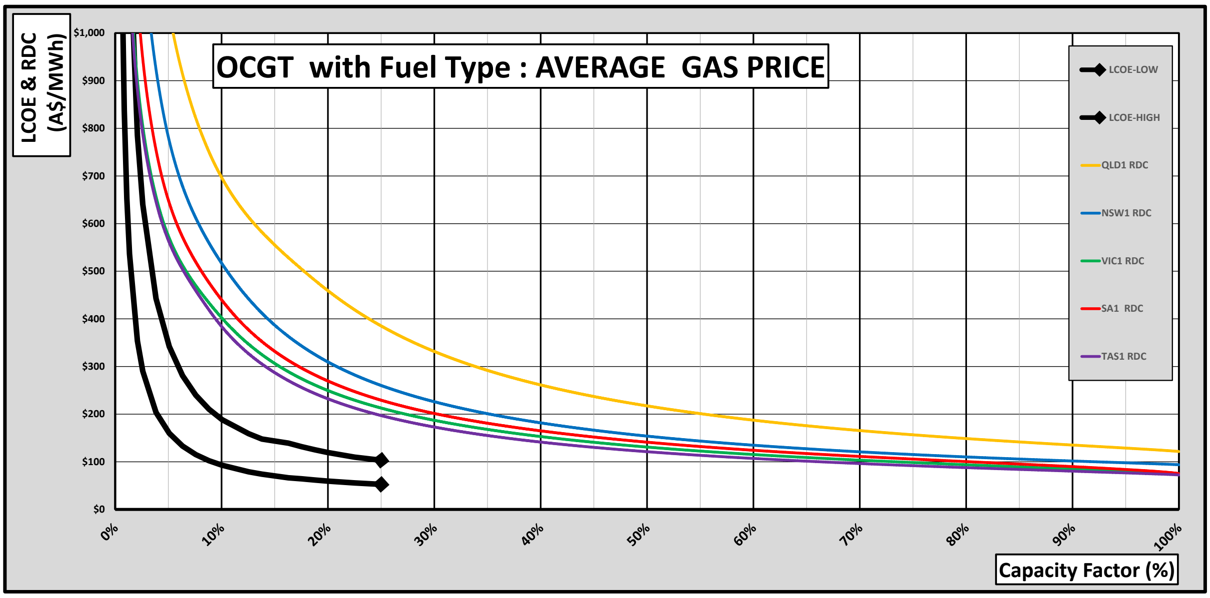
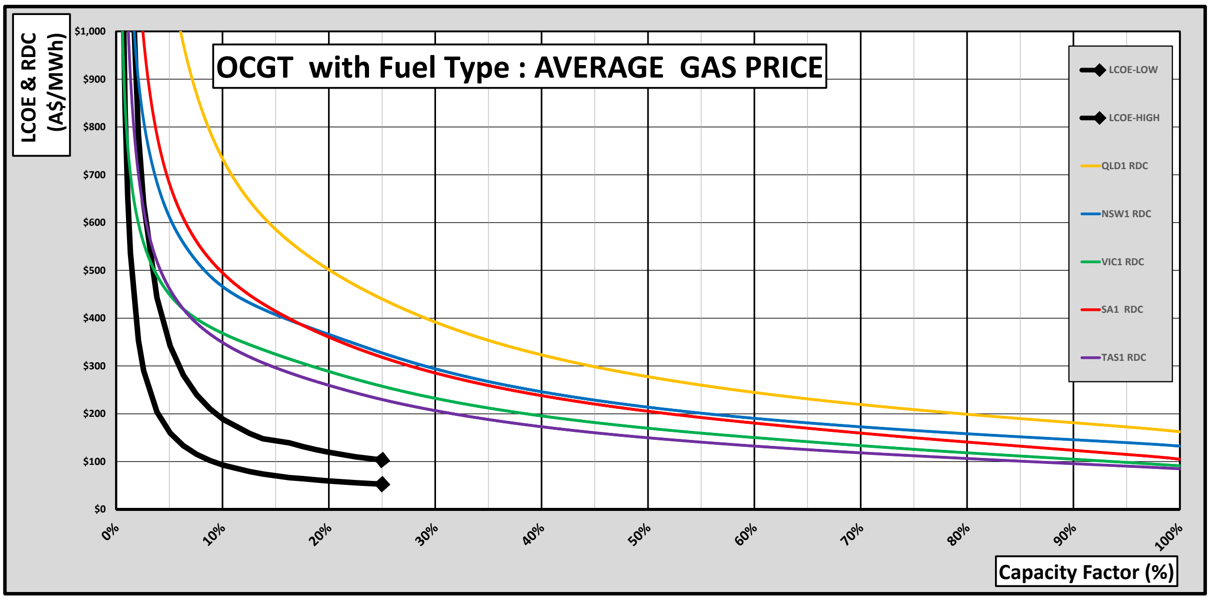


Figure 1.18 OCGT 2021-22



Black Coal

Increasing costs of coal saw our 2021-22 results differ from 2020-21, with high prices in some regions providing mixed signals for investment in coal generation. AEMO's maximum quoted capacity factor for a coal generator is 75%[13], though due increasingly frequent outages, aging coal generators in the NEM typically operate at a capacity factor lower than this. In order to recover its costs:

---

13 AEMO, 2022 ISP Input and Assumptions workbook, v1 Jul 22.

- For the 2020-21 low cost scenario a new entrant coal generator would recover its costs operating at a capacity factor greater than 2.1%, though in the next highest price region (NSW) this figure was 6.9% (Figure 1.19 Black Coal 2021-22). In our high cost scenario, it would be unable to recover its costs operating at any capacity.
- For the 2021-22 low cost scenario a new entrant coal generator would recover its costs operating at a capacity factor greater than 1.8% in Queensland, though in the next highest price region (South Australia) this figure was 5.2% (Figure 1.20 Black Coal 2021-22). For our high cost scenario, a coal generator would be unable to recover its costs operating at any capacity.

Figure 1.19 Black Coal 2021-22

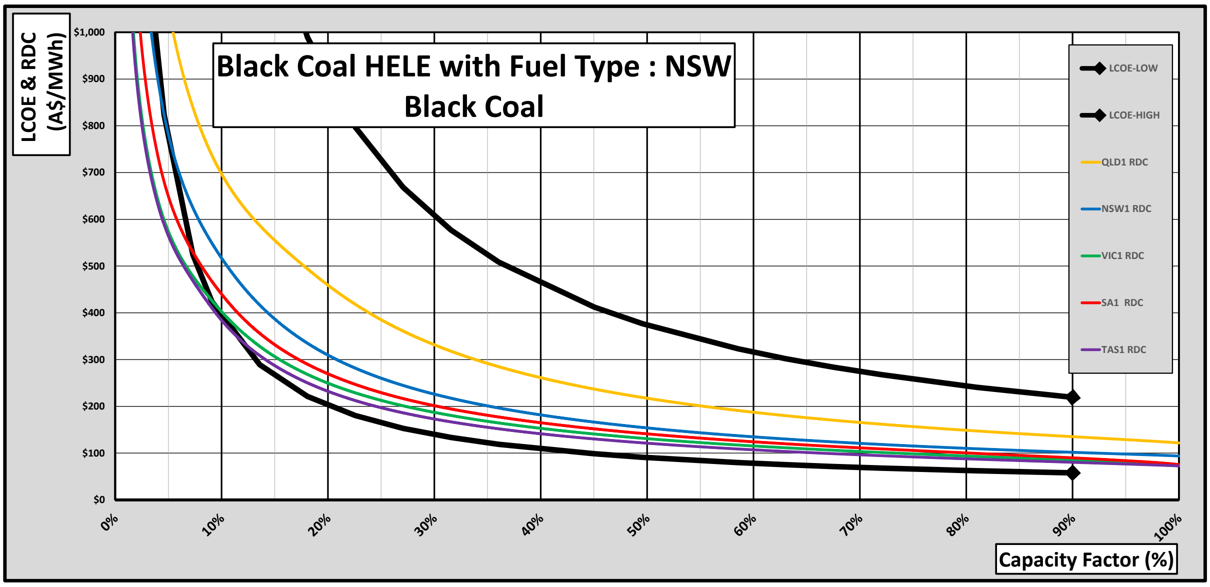
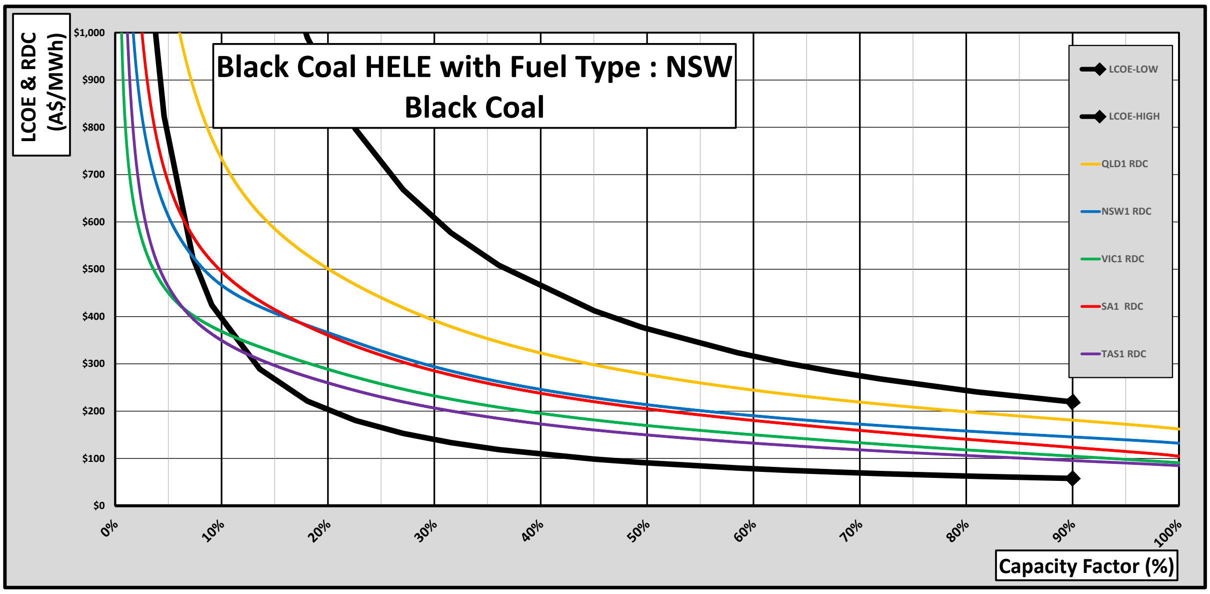


Figure 1.20 Black Coal 2021-22



Reciprocating Internal Combustion Engines (RICE)

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

- For the 2020-21 low cost scenario a new entrant RICE would have an opportunity to recover its costs at all stages of its capacity factor. This was also true of our high cost scenario (Figure 1.21 RICE 2020-21).
- For the 2021-22 low cost scenario a new entrant RICE would have an opportunity to recover its costs at all stages of production. This was also true of our high cost scenario (Figure 1.22 RICE 2021-22).

Figure 1.21 RICE 2020-21

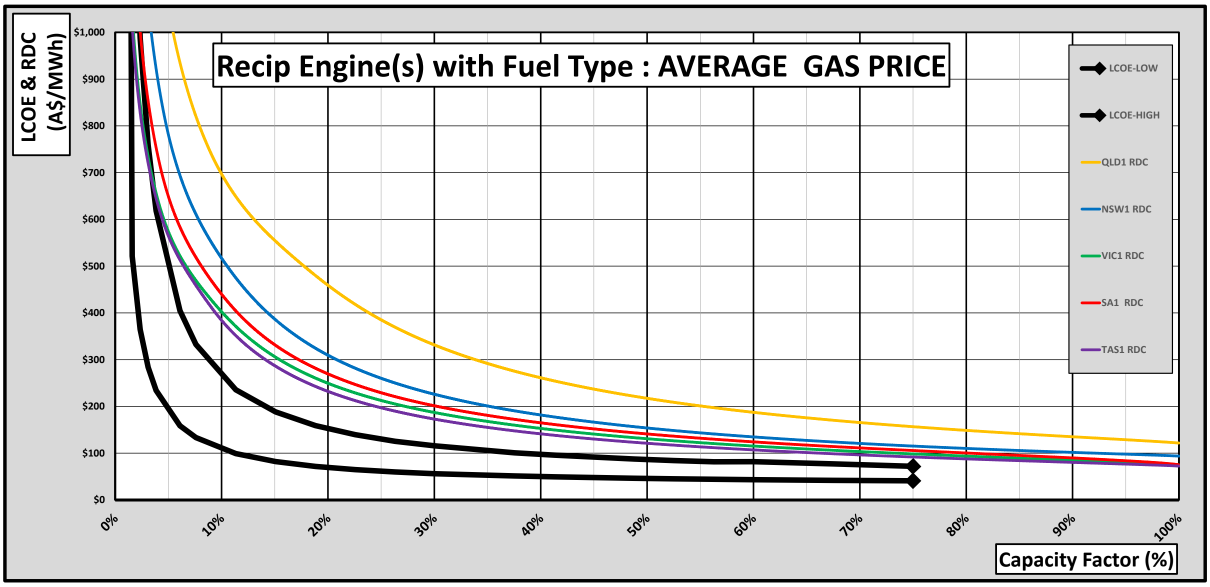
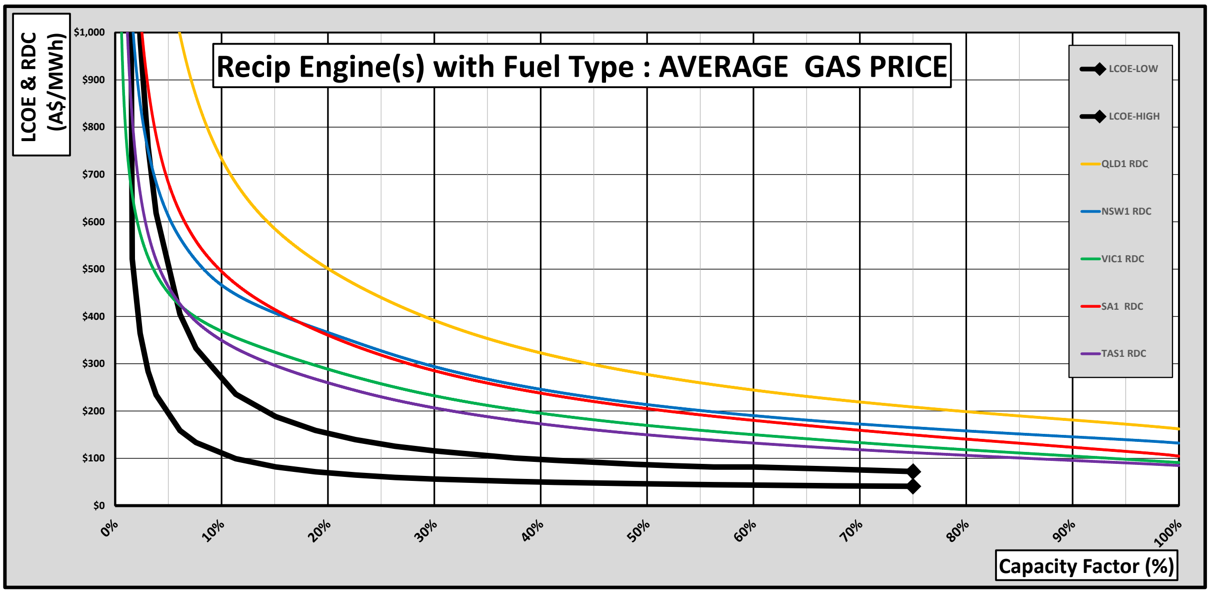


Figure 1.22 RICE 2021-22



2 We used LCOE as a base to assess LCOS

As a measure, LCOS builds on LCOE (Chapter 1). To maintain consistency, we have sought to retain much of the LCOE approach for this LCOS analysis. Where there are changes, this has been to accommodate the operational differences between generation and storage technologies. These changes include:

- LCOS has two main cost drivers: the first based on the power generation or nameplate capacity (in MW), and the second based on the energy storage capacity (in MWh). For example, a battery may have 100 MW of generation capability and 150 MWh of energy storage capacity.
- While the energy input cost for a generator is captured in its fuel cost, for a storage facility the energy input cost is the average price while the storage is filling. A storage participant is likely to store its energy over several trading periods, so an average, rather than individual, energy price is appropriate.
- The discharge of the stored energy can be considered as if it were generation and therefore can be treated similarly to electricity generation in LCOE.
- With fossil fuel-based energy generation, the energy is embedded in the fuel itself. However, for pumped hydro storage the stored energy relies on water (as the physical medium) and the energy given to it by raising its elevation (potential energy). For simplicity, the opportunity cost of water or other water management costs are excluded for this analysis, instead we focus on the cost of storage, as with other technologies.
- As energy storage must precede discharge, we have assumed a daily cycle of buying energy at the lowest price periods in the day before selling it back during the highest price periods of the day.
- We assess this daily cycle over a year, with the data sorted from most profitable trading days to worst, based on the spread between the highest and lowest prices each day. The daily buy (for storage) and sell (for generation) prices must therefore remain paired for this analysis.
- All storage devices do not deliver all of the energy stored because of round-trip efficiencies.
- That is, some energy stored is lost in the process and unable to be discharged. Different technologies have different efficiencies. We have accommodated this by assuming 11 (thirty minute) trading intervals for storage and eight trading intervals for discharge/generation, which implies a 72% round trip efficiency. For simplicity, we apply this 72% efficiency for all storage technologies in this analysis but we will update this assumption in any subsequent version of this analysis if necessary.
- Rather than use capacity factor as we do for the LCOE estimates, we use trading days as the independent variable in our LOCS estimates. Using trading days rather than capacity factors is more accurate because storage cannot generate continuously, as it must recharge and therefore cannot exceed a 50% capacity factor. Additionally, storage technologies are typically fast response, which allows them to optimise energy trades around daily price fluctuations.

By using these simplifying assumptions, the LCOS and price comparison provides a simple indicator in much the same way as the LCOE analysis does. If the price of discharge exceeds the cost of storage, it suggests an incentive for new entry might exist based on energy arbitrage alone.[14]

2.1 Our approach to LCOS

For the 2022 performance report, we surveyed a range of publicly available data on new entrant storage costs, collating results to produce high (worst case) and low (best case) estimate scenarios for each technology type considered. Using a number of assumptions and simplifications, we then calculated the LCOS across a range of trading days. This approach reveals where revenues are likely to exceed costs.

It should be noted that storage costs are difficult to generalise and, with the exception of pumped hydro, grid scale storage is not a mature technology. Therefore economic life, costs and cost trajectories are not yet as established as some of the more conventional generation technologies.

We compared LCOS to potential revenue exposure in each NEM region for 2020-21 and 2021-22. Subsidies and incentives were excluded from this analysis.

For the 2022 performance report, we have estimated LCOS for the following technologies

- Lithium-ion battery
- Lead-acid battery
- Vanadium flow battery
- Zinc-Bromine flow battery
- Pumped Hydro Energy Storage (PHES)

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: LCOS references.

Box 2.1 Different types of storage

For our analysis, we estimate LCOS for pumped hydro energy storage (PHES) and various battery technologies.

In its simplest form a battery is an electrochemical cell that can store and discharge electrical energy. These cells can be co-joined in various configurations to form very large batteries. The operation of the battery is to store electrical energy in a chemical process that can later be reversed to recover most of the previously stored energy. Many batteries are single use, such as the common AA or AAA batteries, but the batteries used for grid-scale storage are able to be recharged and discharged many thousands of times.

[14] Although this behaviour is not aligned with the strictly definition of arbitrage, we use this descriptor to distinguish this behaviour from other possible behaviours of storage technologies. For example, this analysis excludes consideration of ancillary services provision and any associated costs and revenues.

The batteries described in this paper are rechargeable batteries and generally have no moving parts, but the equipment that makes them functional may have moving parts.

The batteries we model include:

- Lithium-ion batteries, which have no moving parts in either the battery or its charge/discharge circuitry. Currently, all batteries in the NEM use lithium-ion technology.
- Lead-acid batteries have no moving parts internally but the charging system and parts of the discharge system may have moving parts. Lead acid batteries are less common for grid-scale storage applications but can be used in smaller off-grid power systems where ambient temperatures do not favour lithium-ion technologies.
- The vanadium and zinc-bromine flow batteries are named as such because they rely on a liquid electrolyte flowing around the battery circuit, and hence need pumps to function. They are readily scaled for grid applications, but are bulky and heavy, which makes them unsuitable for applications where space or weight are important. While there are no grid-scale applications of either flow battery technology in the NEM, a 10 kW/100kWh vanadium flow battery is operational in Busselton, Western Australia.

For PHES, water is repeatedly cycled between a high and low reservoir. The energy stored in the form of water that can be used to fuel potential future generation.

2.1.1 Modelling assumptions

We used the following assumption in calculating LCOS:

- For all technologies, we assumed a size of 100 MW of generation and 400 MWh of storage.
- The facility acts as a load when charging, then acts as a generator when discharging, on a daily cycle. That is, buy low now, sell high later, on the same trading day.
- Charging the storage technology at the lowest possible daily spot prices, which then becomes the fuel cost input for the subsequent generation.
- Charging for a period longer than the discharge (generation) period due to inefficiencies.
  - This analysis assumes a constant 72% efficiency for all technologies.
  - Better efficiencies will allow faster charging times.
  - This model applies all of the round-trip efficiency factors to the charging process, rather than more properly sharing the efficiencies separately between the charging and discharge processes.
  - One adverse consequence of this approach is that the storage is assumed to be able to deliver its full MWh. The physical situation is that the storage may have to be sized at say 10% more than the desired energy output (e.g. a 440 MWh battery may be required to provide a guaranteed 400 MWh discharge). We may address this in future approaches to LCOS estimates.

- The average charge and discharge spot prices are captured, paired and used to inform the fuel cost and RDC respectively.
- Trading days are ranked from highest to lowest sell price during the year. This is reflected in the RDC curves.
- There is the option of trading from one to 365 days per annum, but this analysis constrained the model to consider 12 to 365 days per year as lower and upper bounds. This assumption suggests storage technologies will target a minimum production level.
- Forced outages are assumed to be 0% because the technology will be inactive for about 60% of the time so outages are assumed to be taken when the technology is idle.
- The storages are assumed to be fully discharged each day. Therefore, 365 trading days means that 100 MW was discharged for 4 hours for every day of that year and the RDC represents the average price exposure for that period.
- We have not included regional cost differences for construction, transmission, land values etc. in our estimations.
- We have accounted for project cost variations by examining higher cost and lower cost ranges, resulting in two LCOS curves being created for each technology.
- While it is acknowledged that 4 hours discharge time is only one of the possible scenarios, we selected it as standard because it represents the potential time required for a CCGT to reach full power. CCGT's represent an efficient alternative to storage for firming intermittent renewable technologies.
- 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 conditions) and nameplate capacity.

2.2 Methodology

The simple algorithm at the core of the LCOS calculation is the same as for LCOE (Figure 2.1 LCOS Formula)

Figure 2.1 LCOS 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:
r = discount rate (percent)
n = life of the asset (years)
I_t= Investment expenditure in the year t
M_t = Operations and maintenance expenditure in the year t
F_t = Fuel expenditure in the year t

E_t = Electricity generation in the year t, which is calculated as the number of trading days (between 12 and 365) multiplied by a daily discharge of 400 MWh

2.2.1 Calculation assumptions

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

- NPV is a common formula and is therefore not repeated here. However, we do make specific assumptions for LCOS, which we detail in section 2.2.2.
- 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 EPC for both generation and BoP equipment.[15] 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".
  - Fixed and variable operating and maintenance costs—Fixed costs are independent of capacity factor and inflate at the CPI rate. Variable costs are dependent on capacity factor and inflate at CPI rate.
  - Fuel costs—for the storage technologies, the fuel costs are the spot prices at which the storage is undertaken, or the average of those prices if storage is over more than one spot price interval.
  - Major overhaul costs—major overhauls are defined as those that return the generation levels to the same residual standard and residual life as a new facility. Overhaul costs are modelled as being dependent on EOH and inflate at CPI rate. It is acknowledged that there is a time based degradation that should be additionally considered, however this is beyond the scope of this model.
- Costs are averages and are therefore not adjusted for site-specific or region-specific factors.
- Forced outage rates are assumed. These are defined as breakdown or other outage periods when operation would otherwise have occurred.
- Because PHES facilities typically have lives of more than 50 years, all technologies here are modelled out to 60 years to enable a like-for-like comparison of asset life, with overhauls as required to maintain asset functionality. However, in practice some storage technologies are likely to have a shorter asset life.
- Costs don't include:
  - The construction of new transmission lines, or the lines from the station to the nearest TNSP connection point, and any associated loss factors.
  - Fuel transmission or transportation costs are generally not relevant for storage technologies.

[15] 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 are not considered. (e.g. Site remediation costs less scrap value of retired plant).

Other limitations are explained in section Limitations when Comparing LCOS and RDC.

2.2.2 Specific assumptions in NPV calculation

We consider the following in our NPV calculation:

- Currency is nominally in 2021 Australian dollars.
- Discount rate used is WACC.
- Capital construction costs are to go from a greenfields site to a generation ready facility, including EPC and commissioning.
- The number of years over which capital costs are to be spread. For example, a battery may take less than 12 months to spend all its capital in getting generation ready, whereas a major hydro scheme may take many years.
- We assume a plant's construction costs commence at the start of the first year of generation. Plants which 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 our LCOS algorithm, so we have made some assumptions, including:
  - 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 energy production.
  - The spend profile during the construction period is based on distribution of the capital expenditure on an equal and constant percentage basis. For example, if it is a four year build, then we will apportion the costs as 25% for each year of construction.
  - 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.
  - 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 assumed CPI rate.
  - VOM costs are all costs that are zero if the generator doesn't operate. We increase these annually in line with the assumed CPI rate.
  - Major overhaul costs return the facility to 'as new' condition in terms of residual life and storage capacity.
  - We do not account for minor overhauls or inspections or exit costs in the cash flow model.
  - WACC is a critical input because the NPV calculation uses it to discount all future cash flows. While WACC is dependent on firm specific parameters, we cannot know these values for a "levelised" company, and have therefore made some bounded assumptions in understanding the WACC range. For our purposes in

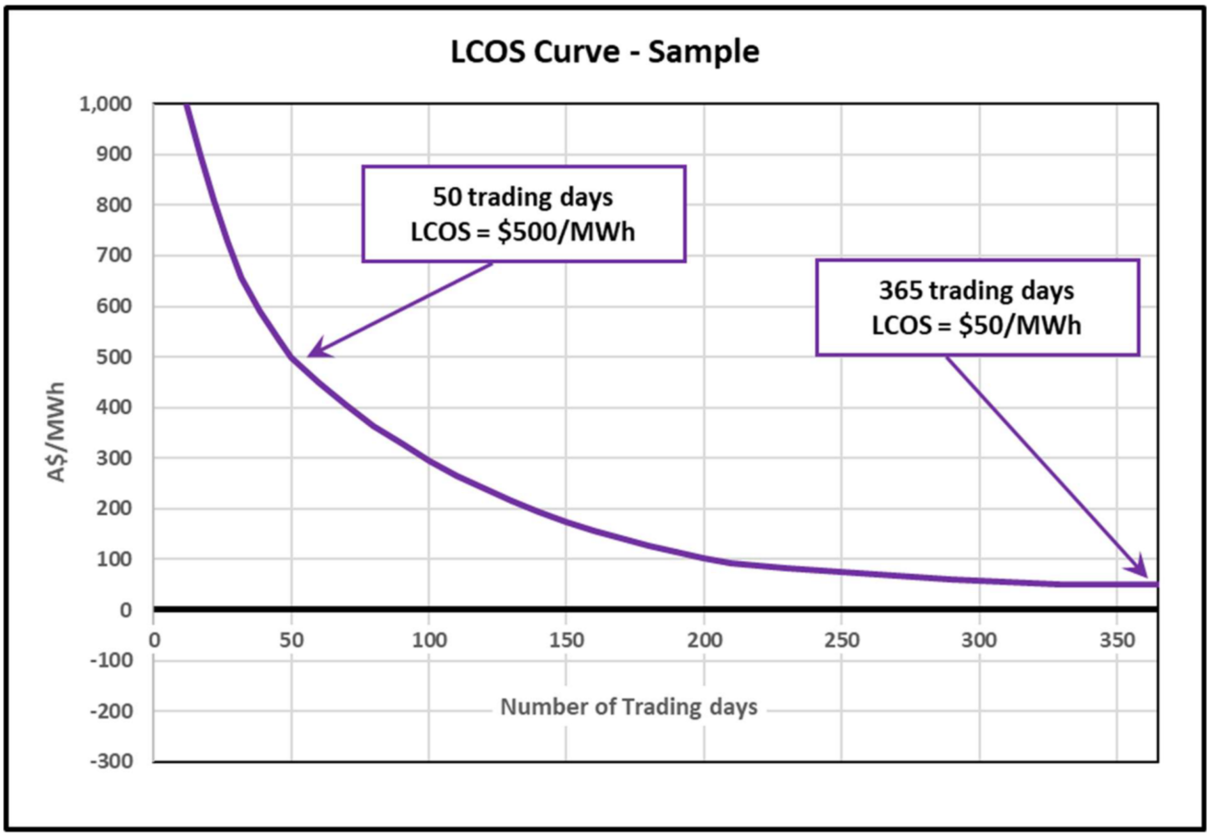
estimating new entrant LCOE, we will use a WACC range of between 7% and 9.5%. While we acknowledge that proven technologies might attract a lower WACC than unproven technologies, no such distinction is made for this model.

– We examined CPI data from the Australian Bureau of Statistics, but some costs are not correlated to the Australian economy alone, therefore, our model assumes a 2% to 3% range for CPI inflation.[16]

2.3 LCOS curve

In accordance with the methodology outlined, we distribute costs across the potential trading days for each technology. In doing so we construct a curve of LCOS estimates (Figure 2.2 Sample LCOS curve).

Figure 2.2 Sample LCOS curve



In our example, if a storage facility discharges energy for 50 trading days per year, its levelised costs are $500 per MWh. Similarly, if the same facility instead discharges energy every day of the year, its levelised costs equal the value of the LCOS curve evaluated at 365 days, or around $50 per MWh.

2.4 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. For our purposes, when a storage facility is charging, it receives the average price for our assumed 5.5 hour charging period and when discharging it receives the average price for our assumed four

---

16 ABS, Consumer Price Index, Australia

hour discharging period. We also assume that a storage facility will behave in such a way to prioritise the most profitable days over of the least profitable days, and that it is able to bid in a matter that allows it to determine when it charges or discharges. From this we can construct a proxy RDC by calculating the highest four hour average price for each per day and ranking these from most-to-least profitable. This is shown graphically in Appendix C: Buy/ Sell Price Analysis Methodology of this report. This trading strategy relies on daily price volatility being in excess of variable operating costs.

For the 2020-21 and 2021inancial years, we calculated an RDC for each NEM region:

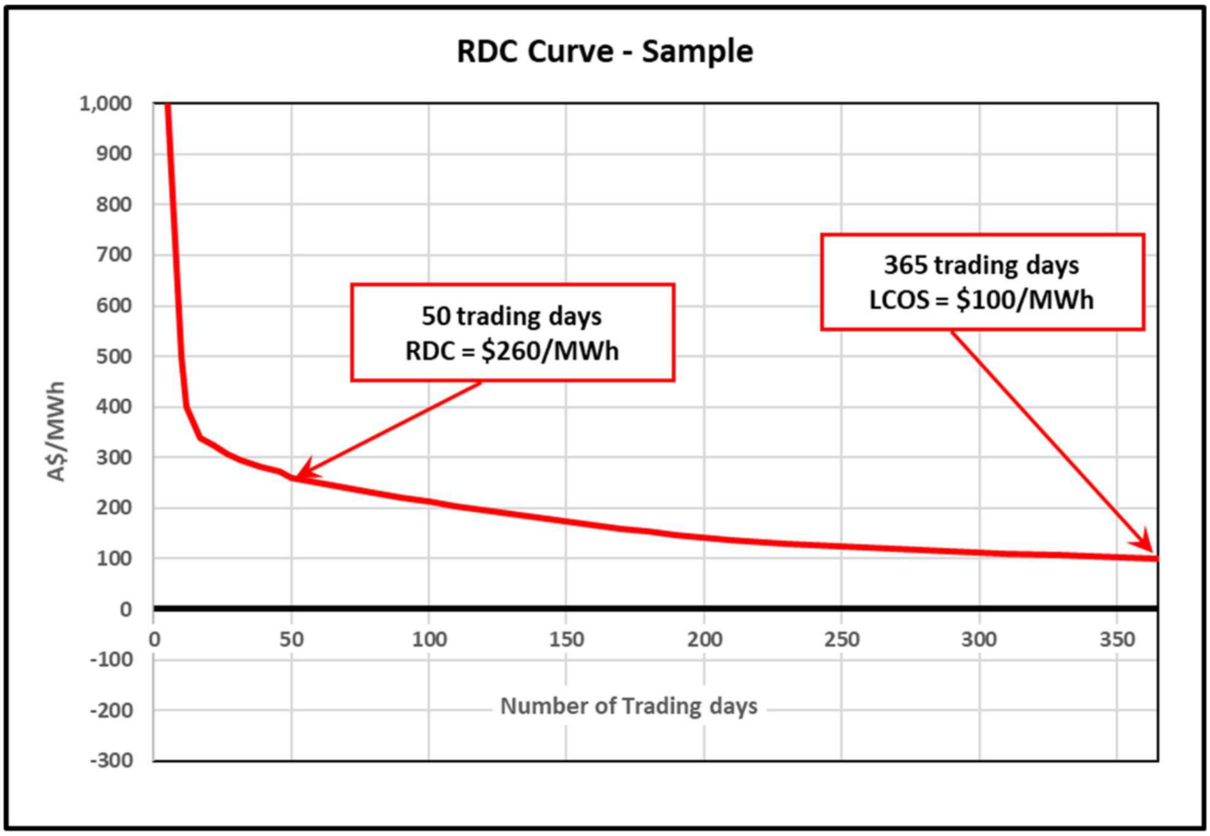
- Queensland
- New South Wales
- Victoria
- South Australia
- Tasmania

2.4.1 Revenue Duration Curve Construction for LCOS

In calculating the RDC, we take the following steps:

1. Take the regional reference price (RRP) for each region for every 30 minute period.
2. Find the best four hour (eight period) average spot price in the day, for each day of then financial year.
3. Sort RRPs from highest to lowest value to form the PDC.
4. Average the PDC to form the RDC. (e.g. the RDC on day 2 is the average of RRP_1 and RRP_2).
5. Plot RDCs across a one to 365 days base for the full financial year (Figure 2.3 Sample RDC).

Figure 2.3 Sample RDC

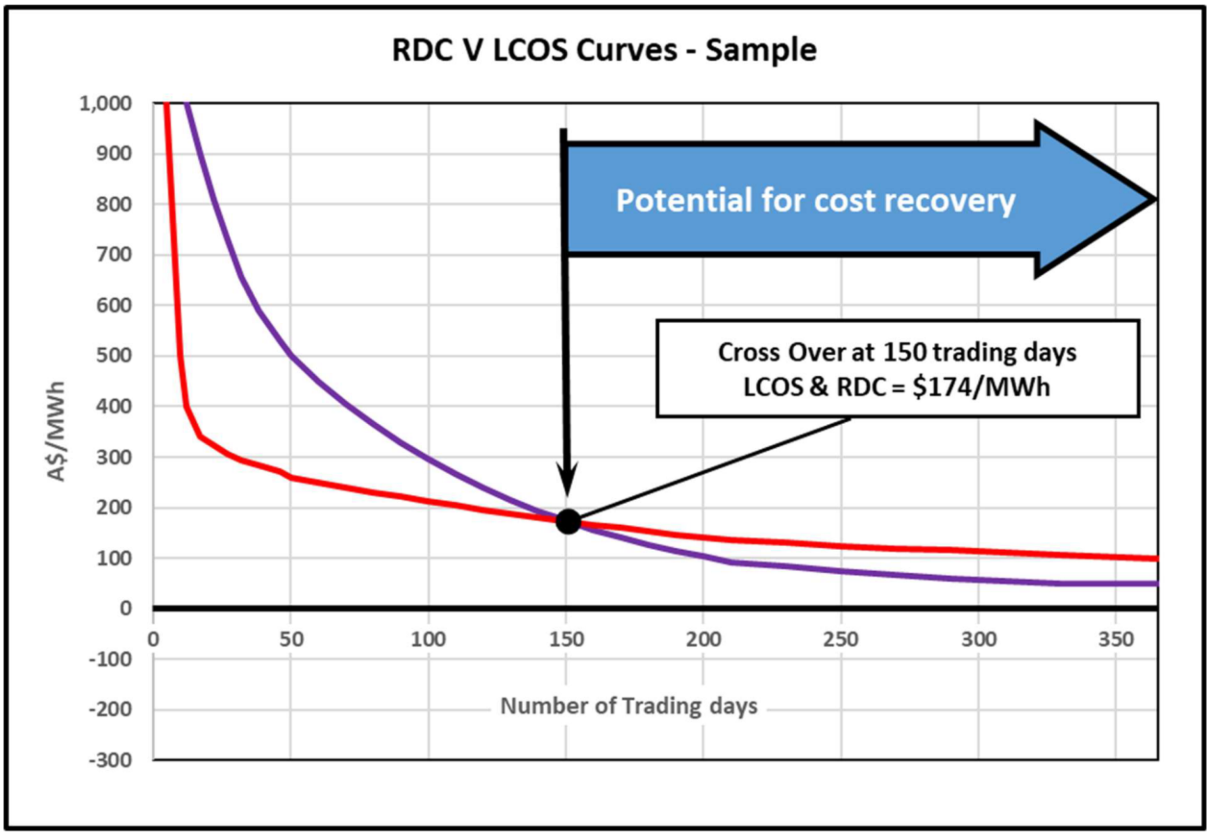


In our example, if a storage facility operates 50 trading days in a year, on average it will receive $260 per MWh for the energy it discharges. Similarly, if the same facility instead operates every day of the year, on average it will receive $100 per MWh.

2.5 Comparing LCOS and RDC

Illustrating the LCOS curve on the same graph as the RDC provides a high level visual indicator of the relationship between potential revenue and operating costs (Figure 2.4 Sample RDC and LCOS comparison).

Figure 2.4 Sample RDC and LCOS comparison



If the RDC exceeds the LCOS at any point, then there may be an opportunity for a storage facility of that technology to fully recover its costs in that year. In our example, if a storage participant operates for more than 150 trading days in a year, it will be able to recover its costs

A prospective storage participant 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.

2.6 Limitations when Comparing LCOS and RDC

LCOS paired with the four hour daily average RDC is a simple, unsophisticated tool designed to provide a high level indication of the potential of cost recovery for a given technology. This has the benefit of making it accessible, transparent and easily compared 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 storage facilities that only sell electricity into the spot market. New entrants would be expected to consider other potential sources of revenue, such as ancillary services, in establishing a business model. They also might consider risk management options, such as financial hedging, which would affect their revenues and bidding strategies.

- We do not consider a portfolio approach to storage/generation where many participants have a range of technologies in their generation fleet.
- We assume that a new entrant has the ability to choose bidding strategies that influence when it charges and discharges, allowing it to target certain production levels.
- Network congestion and constraints can affect a new entrant's ability to achieve the expected revenue.
- LCOS assumes that the facility is a price taker and is not able to influence the price by its presence in the market.
- We exclude transmission connection and other site specific or environmental costs from our estimations.
- We use the same WACC across all technologies. However, WACC is a unique parameter and will differ between companies and between technology types. Our modelled WACC values also do not vary over time, whereas a firm's WACC might change over time.
- We have calculated LCOS in 2022 Australian dollars. However, while some technologies are expected to transition to lower costs, particularly storage technologies, this paper has not speculated on the extent of that transition.

2.7 Findings

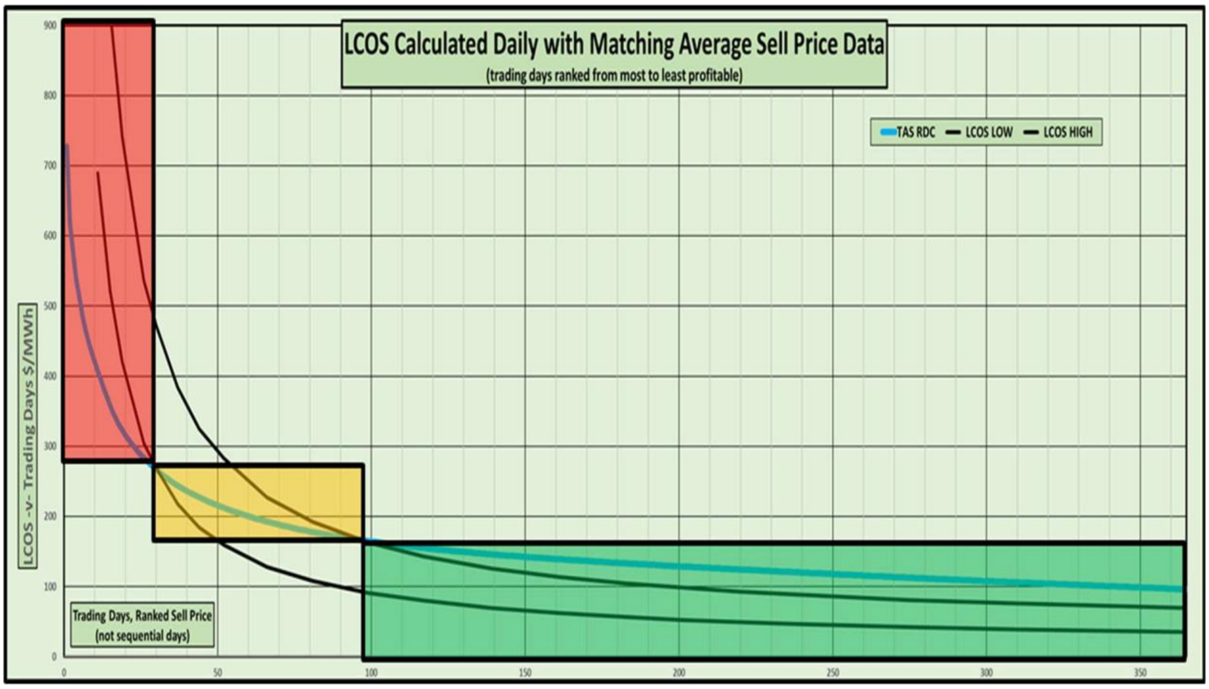
Below we discuss in further detail the results of our LCOS estimations. First, summarised as presented in the 2020 performance report (section Summary of results). Then, we provide the full detailed results (section Detailed LCOS curves).

2.7.1 Summary of results

We created high/low LCOS estimate curves and compared them to the regional RDC to those curves. Based on our findings, we have summarised our analysis using simple colour coded bar charts (Figure 2.5 Example LCOS and RDC curves with colours). For our findings:

- Where the RDC is below the lowest LCOS curve the potential for cost recovery is considered unlikely and hence it is colour coded red.
- Where the RDC is between the lowest and highest LCOS curves the potential for cost recovery is considered possible in optimal circumstances and hence it is colour coded yellow.
- Where the RDC is above the highest LCOS curve the potential for cost recovery is considered likely and hence it is colour coded green.

Figure 2.5 Example LCOS and RDC curves with colours



For all modelled storage technologies, our analysis suggest that prices are sufficient for a new entrant to recover their costs in both 2020-21 and 2021-22 (Figure 2.6 Summary of results for 2020-21 (Figure 7.4 in main report) and Figure 2.7 Summary of results for 2020-21 (Figure 7.5 in main report)).

Appendix D: Calculated Construction Cost Comparison offers a comparison of the construction cost calculations from this model compared with some recent battery projects in Australia.

Figure 2.6 Summary of results for 2020-21 (Figure 7.4 in main report)

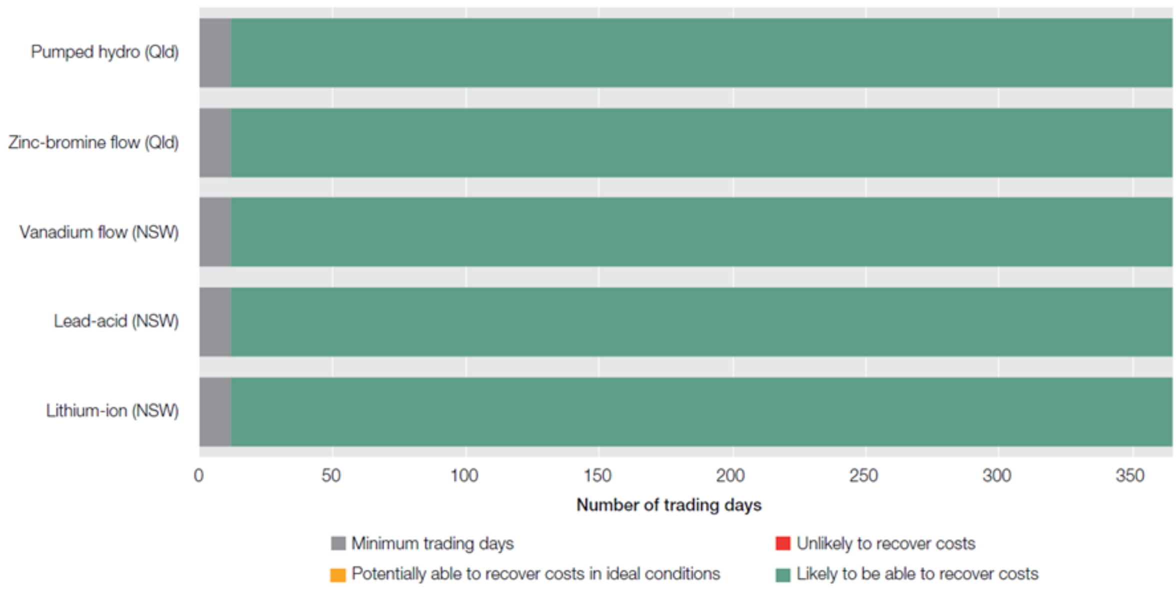
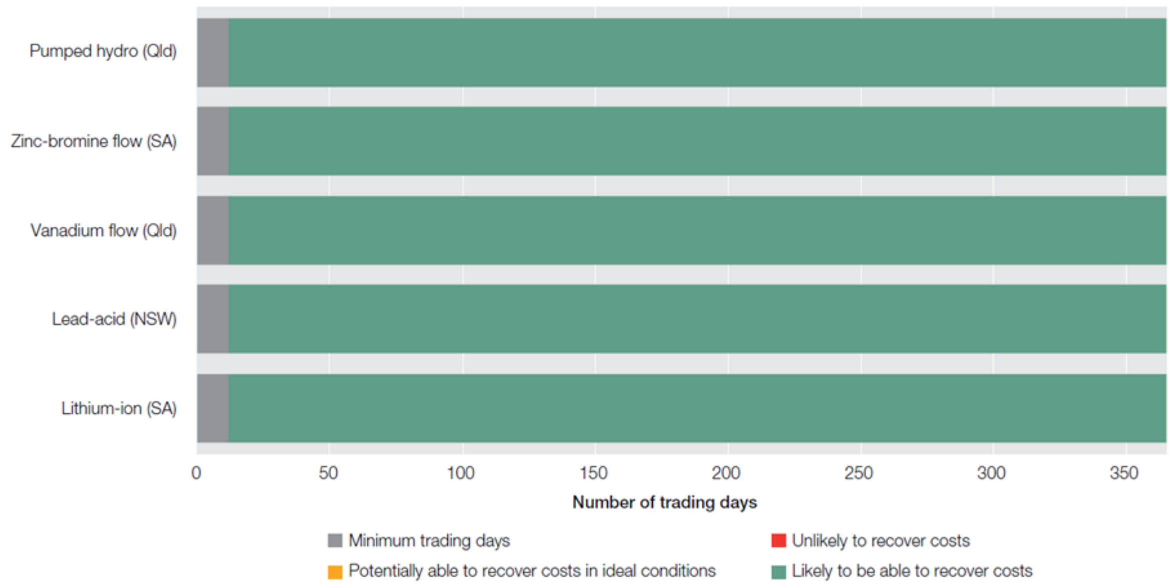


Figure 2.7 Summary of results for 2020-21 (Figure 7.5 in main report)



2.7.2 Detailed LCOS curves

The detailed charts of our full estimations follow. For each technology, there are two charts representing the financial years considered.

Lithium-ion battery storage

Based on our estimations, in order to have an opportunity to recover its costs:

- For 2020-21, a new entrant lithium-ion battery is likely to recover its costs at all levels of operation (Figure 2.8 2020-21 Lithium-Ion Battery storage).
- For 2021-22, a new entrant lithium-ion battery is likely to recover its costs at all levels of operation (Figure 2.9 2021-22 Lithium-Ion Battery Storage).

Figure 2.8 2020-21 Lithium-Ion Battery storage

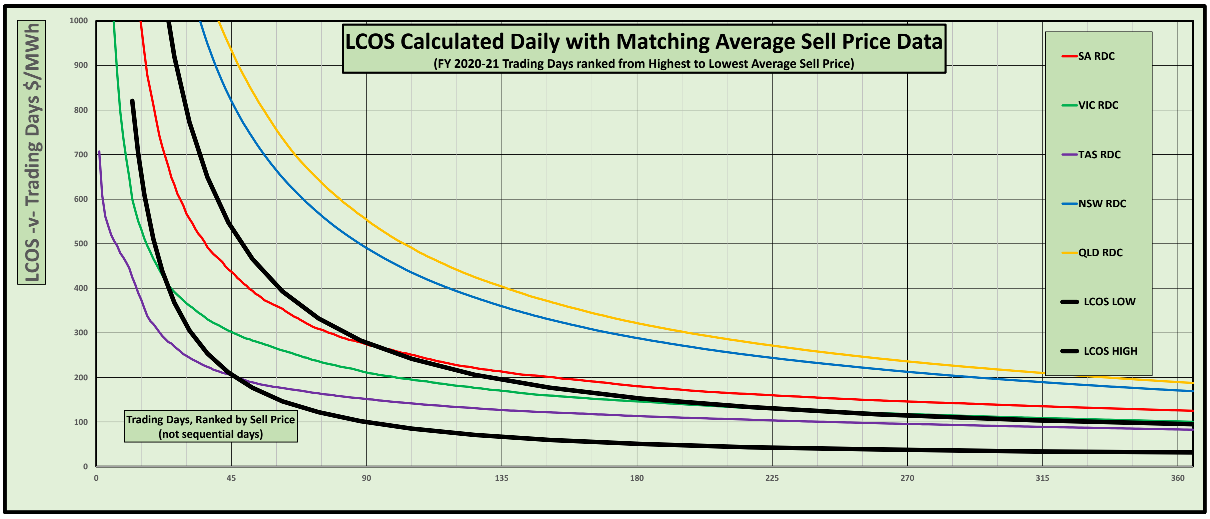
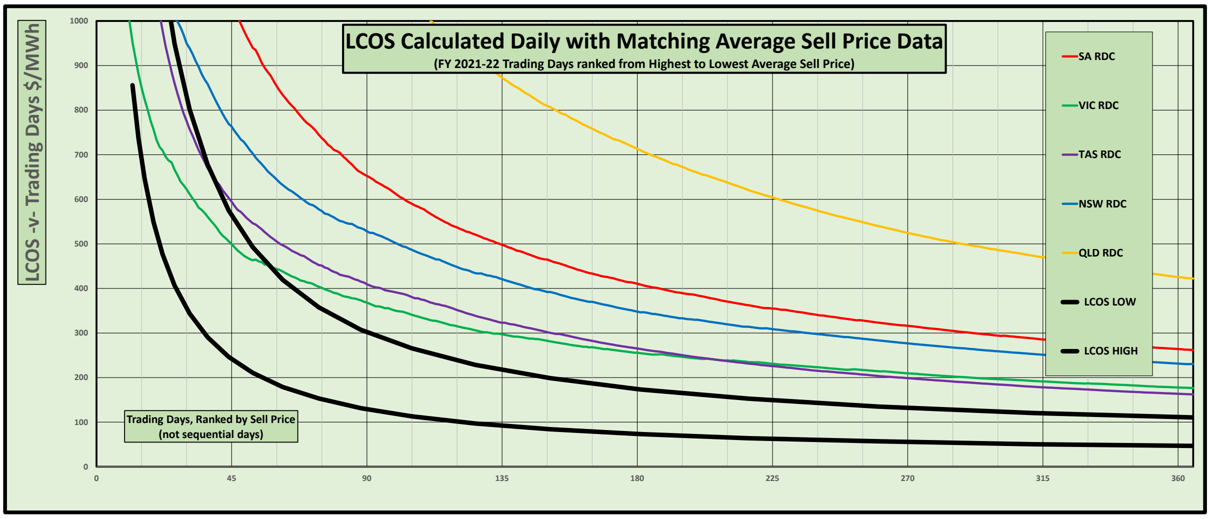


Figure 2.9 2021-22 Lithium-Ion Battery Storage



Lead-acid battery storage

Based on our estimations, in order to have an opportunity to recover its costs:

- For 2020-21, a new entrant lead-acid battery is likely to recover its costs at all levels of operation (Figure 2.10 2020-21 Lead-acid Battery Storage).
- For 2021-22, a new entrant lead-acid battery is likely to recover its costs at all levels of operation (Figure 2.11 2021-22 Lead-acid Battery Storage).

Figure 2.10 2020-21 Lead-acid Battery Storage

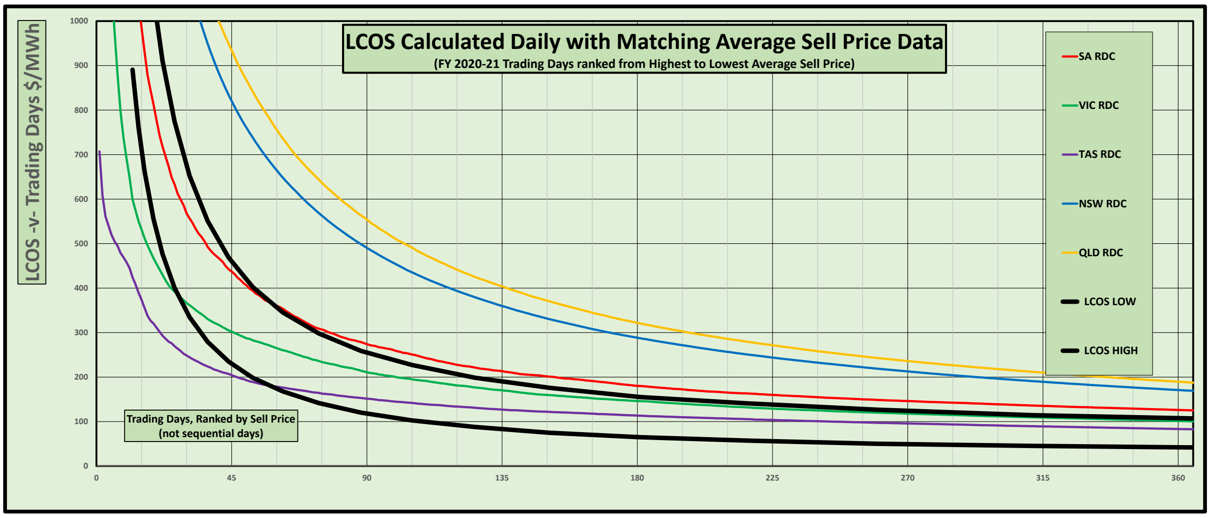
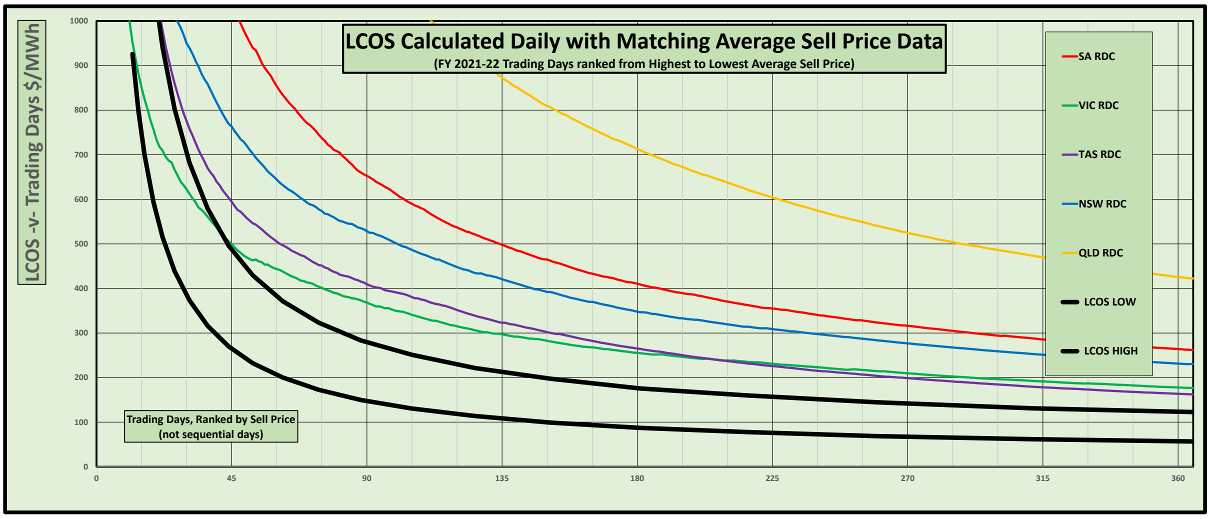


Figure 2.11 2021-22 Lead-acid Battery Storage



Vanadium flow battery storage

Based on our estimations, in order to have an opportunity to recover its costs:

- For the 2020-21, a new entrant vanadium flow battery is likely to recover its costs at all levels of output (Figure 2.12 2020-21 Vanadium flow battery storage).
- For the 2021-22, a new entrant vanadium flow battery is likely to recover its costs at all levels of operation (Figure 2.13 2021-22 Vanadium Flow Battery Storage).

Figure 2.12 2020-21 Vanadium flow battery storage

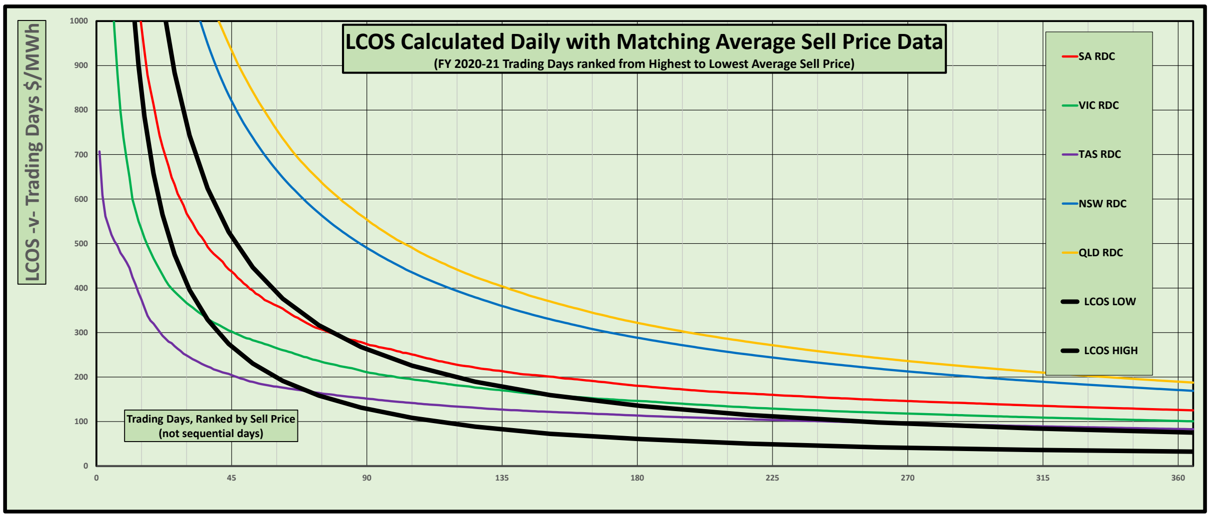
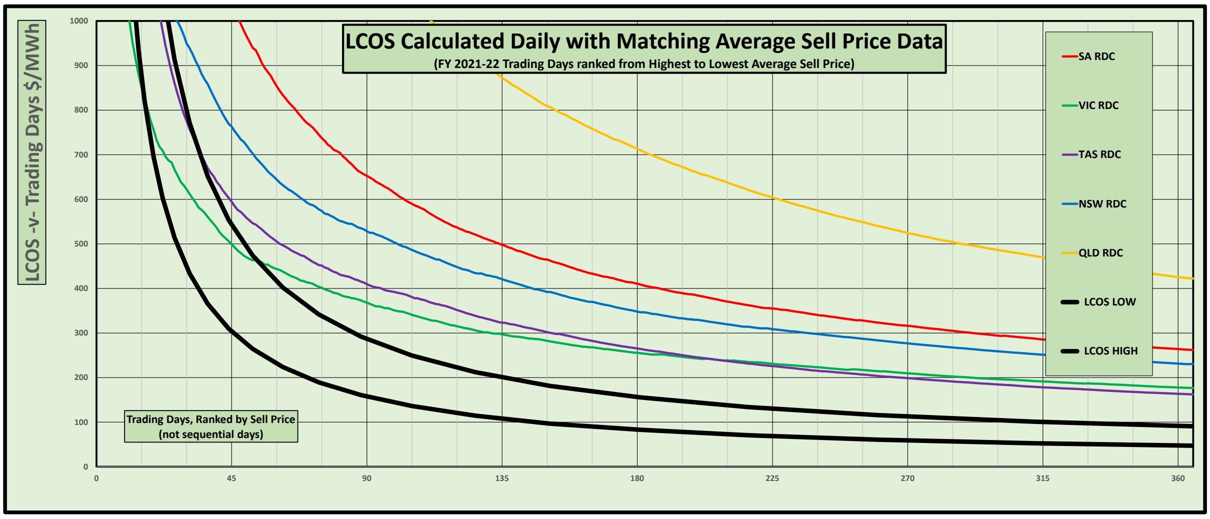


Figure 2.13 2021-22 Vanadium Flow Battery Storage



Zinc-bromine flow battery storage

Based on our estimations, in order to have an opportunity to recover its costs:

- For 20120-21, a new entrant zinc-bromine flow battery is likely to recover its costs at all levels of operation (Figure 2.14 2020-21 Zinc-bromine flow battery storage).
- For 2021-22, a new entrant zinc-bromine flow battery is likely to recover its costs at all levels of operation (Figure 2.15 2021-22 Zinc-bromine flow battery storage).

Figure 2.14 2020-21 Zinc-bromine flow battery storage

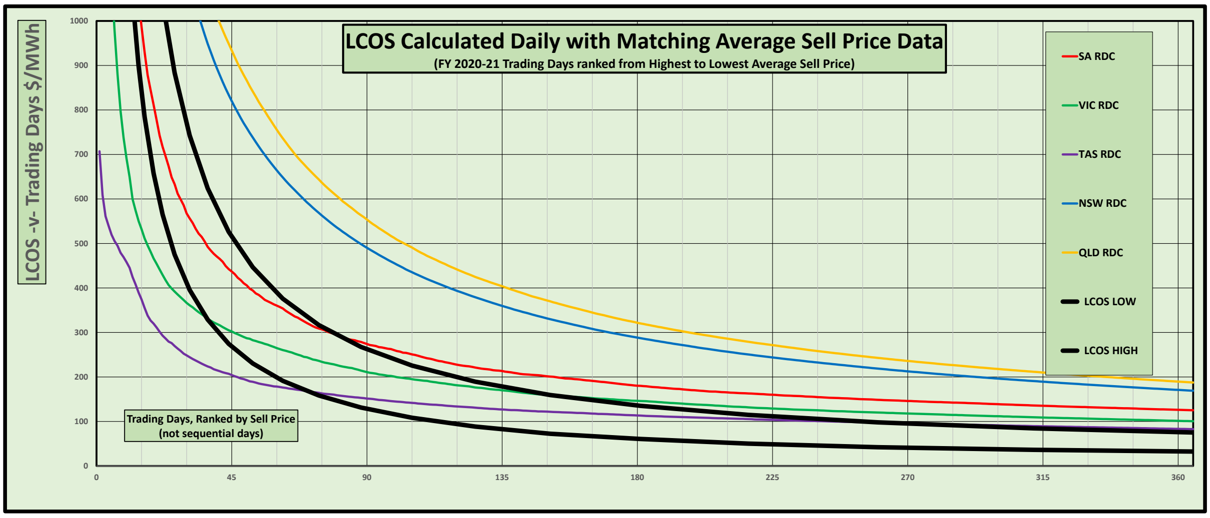
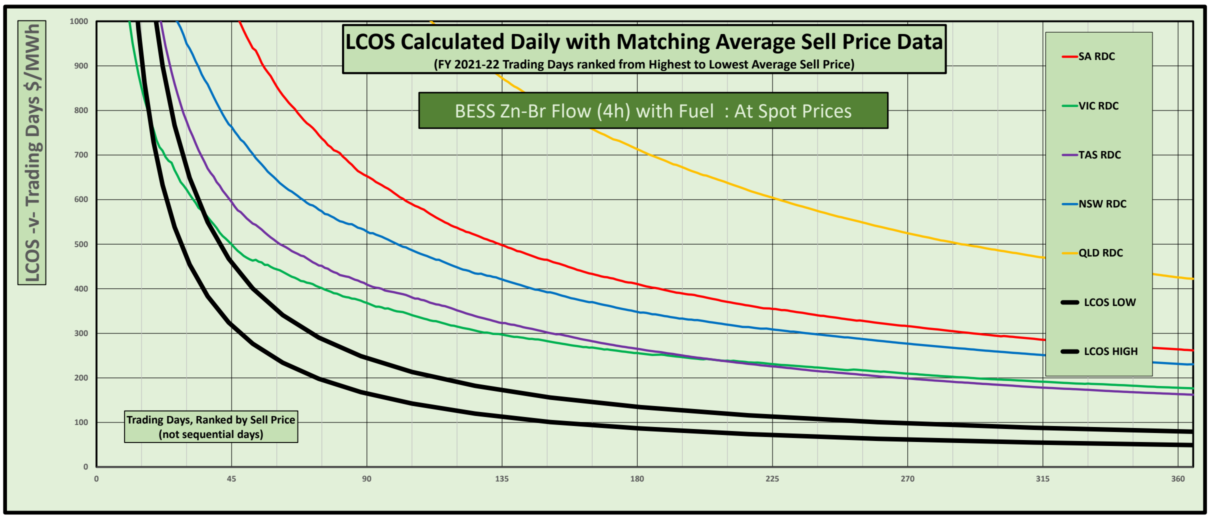


Figure 2.15 2021-22 Zinc-bromine flow battery storage



Pumped hydro energy storage

In order to have an opportunity to recover its costs:

- For the 2020-21, a new entrant PHES is likely to recover its costs at all levels of operation (Figure 2.16 2020-21 Pumped hydro energy storage).
- For the 2021-22, a new entrant PHES is likely to recover its costs at all levels of operation (Figure 2.17 2021-22 Pumped hydro energy storage).

Figure 2.16 2020-21 Pumped hydro energy storage

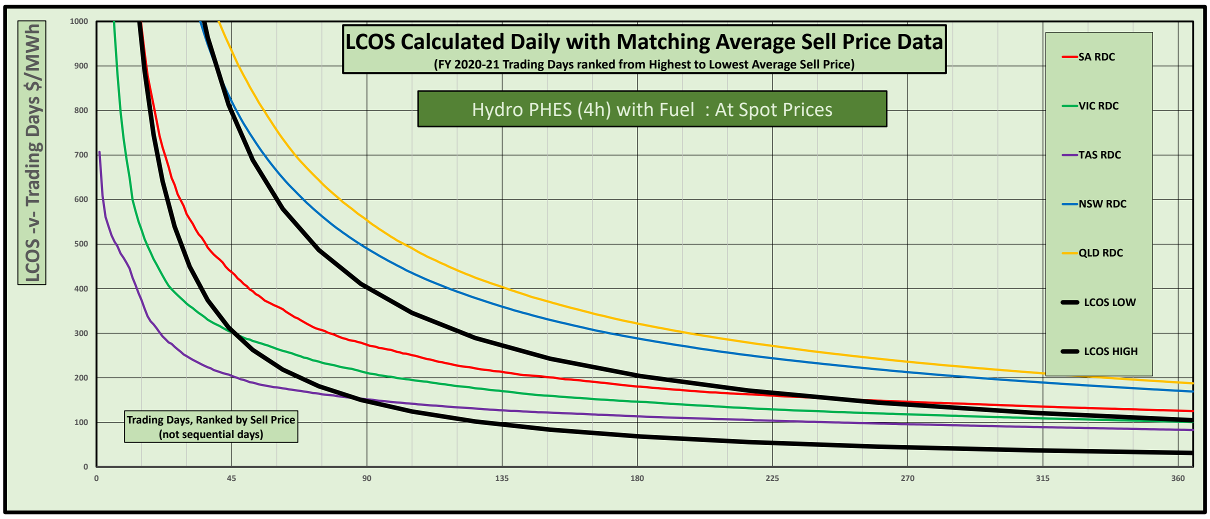
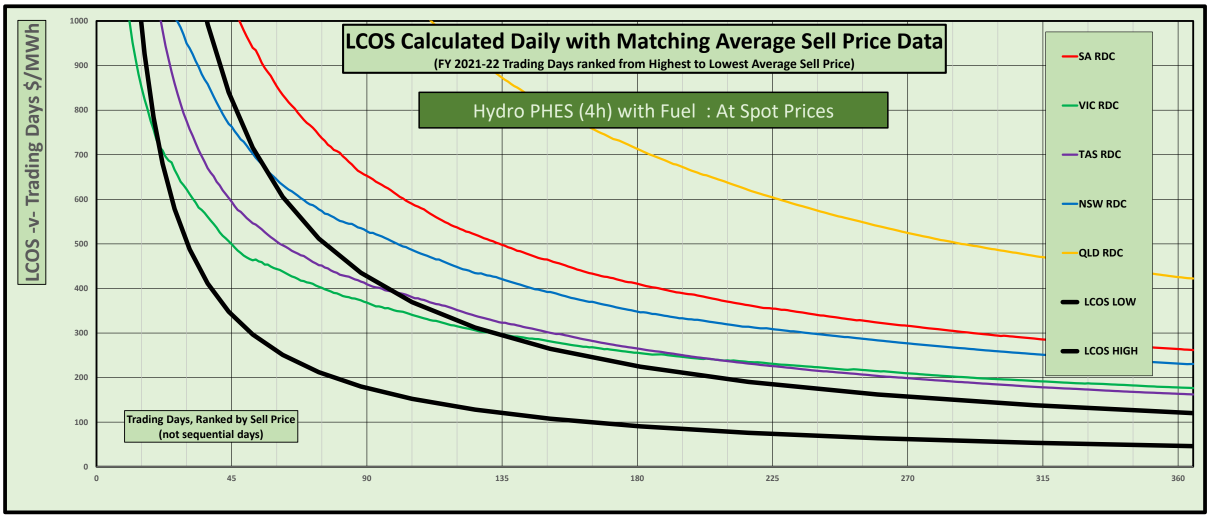


Figure 2.17 2021-22 Pumped hydro energy storage



Appendix A: LCOE References

ACIL Allen Consulting, Report to Australian Energy Market Operator - Fuel and Technology Cost Review. 10 June 2014.

AEMO 2022 Input and Assumptions workbook v1 30 Jun 2022 AEMO ISP

Aurecon 2021 Costs and Technical Parameter Review Consultation Report

Australian Energy Market Operator (AEMO) Reference: 512485 Revision: 1 2021-27-10 https://aemo.com.au/-/media/files/major-publications/isp/2022/iasr/aurecon-2021-cost-and-technical-parameters-review-report.pdf?la=en

Dr Alan Finkel AO, Ms Karen Moses FAICD, Ms Chloe Munro, Mr Terry Effeney, Professor

Mary O'Kane AC (Finkel Report), Independent Review into the Future Security of the National

Electricity Market - Blueprint for the Future. June 2017.

Gas Turbine World, 2022 GTW Handbook, Vol 37. 2022.

Gas Turbine World, 2018 GTW Handbook, Vol 37. 2022.

Gas Turbine World, 2017 Performance Specs, Edition 37. 2022.

Hayward, J.A. and Graham, P.W. (CSIRO), Electricity generation technology cost projections: 2017-2050. 2017.

International Renewable Energy Agency (IRENA), Renewable Power Generation Costs in 2021. July 2022.

LAZARD, LAZARD's Levelized Cost of Energy Analysis – Version 15.0, October 2021

Parsons Brinckerhoff, Thermal Power Station Advice - Reciprocating Engines Study. November 2009.

U.S. Department of Energy (US DOE), Combined Heat and Power Technology Fact Sheet Series - Reciprocating Engines. July 2016.

Appendix B: LCOS references

AEMO, 2022 Input and Assumptions workbook v1 30 Jun 2022 AEMO ISP

Aurecon, 2021 Costs and Technical Parameter Review Consultation Report

Australian Energy Market Operator (AEMO) Reference: 512485 Revision: 1 2021-27-10 https://aemo.com.au/-/media/files/major-publications/isp/2022/iasr/aurecon-2021-cost-and-technical-parameters-review-report.pdf?la=en

Graham P, Hayward J, Foster J, Havas L(CSRIO_ , GENcost 2020-21, July 2021
HydroWires Energy Storage Technology and Cost Characterization Report July 2019

US Dept of Energy PNNL-28866 Table ES.1

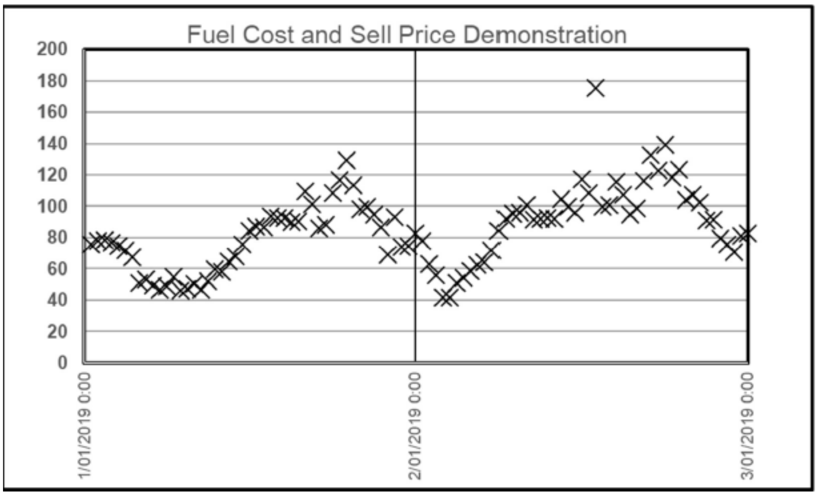
K Mongird V Fotedar V Viswanathan V Koritarov P Balducci B Hadjerioua J Alam https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance %20Characterization%20Report_Final.pdf

LAZARD, LAZARD's Levelized Cost of Storage — Version 7.0. October 2021

Appendix C: Buy/ Sell Price Analysis Methodology

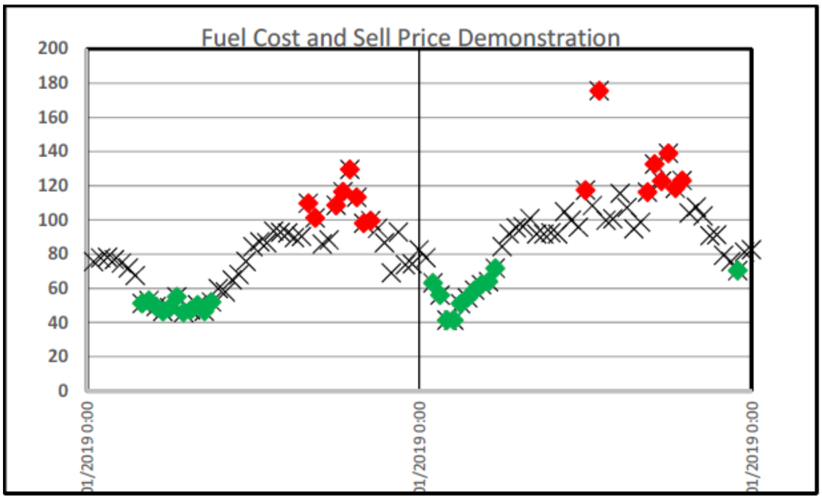
The following plot illustrates the logic of the construction of the LCOS RDC curve. This plot is for the RRP for first two days of 2019 in SA to illustrate the method (Figure C.1 South Australian energy prices 1 and 2 January 2019).

Figure C.1 South Australian energy prices 1 and 2 January 2019



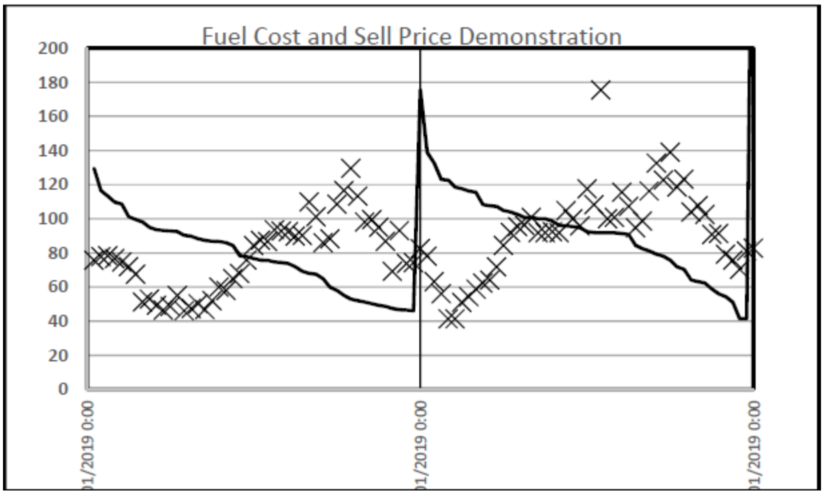
We note the low and high price data of interest (Figure C.2 Highest and lowest energy prices in SA, 1 and 2 January 2019).

Figure C.2 Highest and lowest energy prices in SA, 1 and 2 January 2019



By sorting these daily prices high to low we can construct the daily PDC (Figure C.3 South Australia Price Duration Curve, 1 and 2 January 2019).

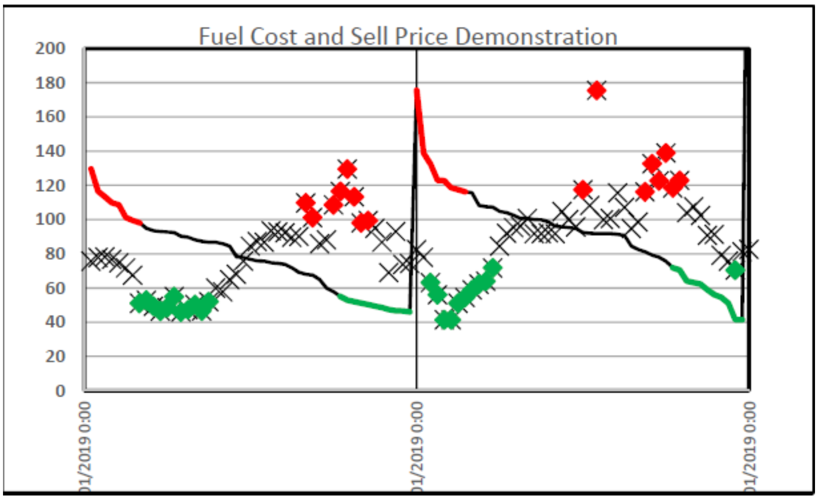
Figure C.3 South Australia Price Duration Curve, 1 and 2 January 2019



If we then take the average of the highest four hours of prices for the day, as the average sell price and the average of the lowest 5.5 hours for the day (72% efficiency) as the average fuel cost, then we have data to inform the fuel cost and the sell price for the day (Figure C.4 Highest and lowest prices in SA with Price Duration Curve, 1 and 2 January 2019).

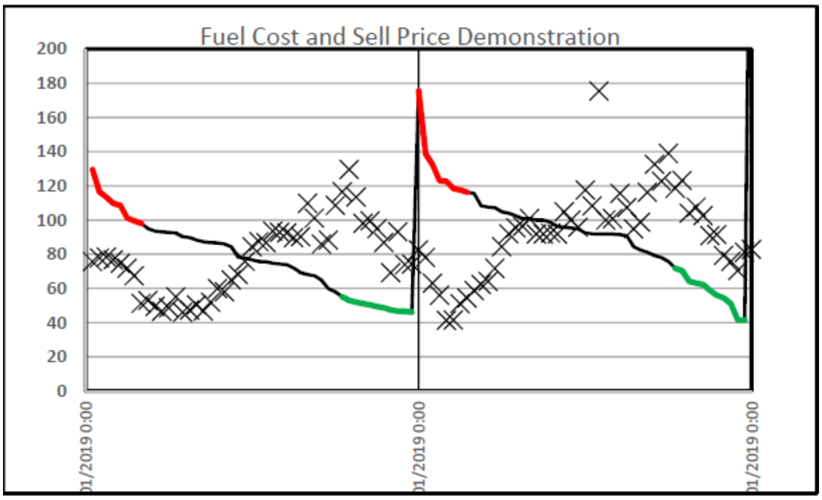
If we keep the colour coding it can be seen that the modelled “buy low/sell high, sell before you buy” outcomes are reasonably represented by this approach.

Figure C.4 Highest and lowest prices in SA with Price Duration Curve, 1 and 2 January 2019



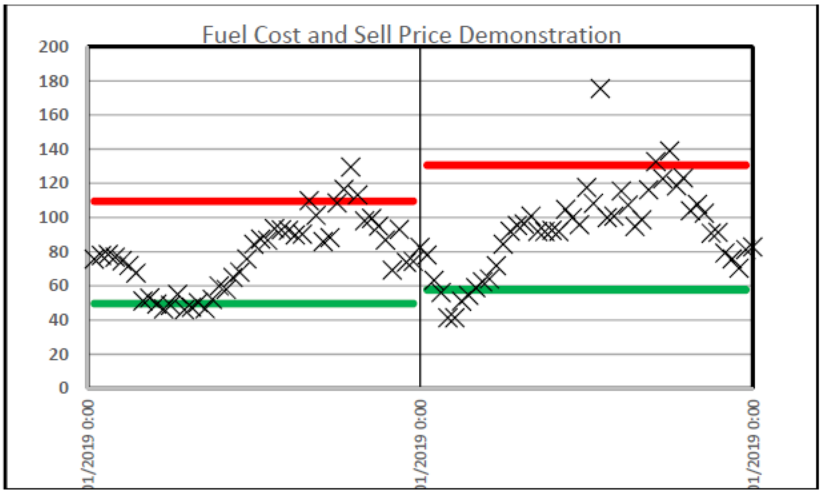
The sell prices (for the RDC) are the red lines and the buy prices (fuel cost) are the green lines overlaid on this daily PDC (Figure C.5 South Australian Revenue duration curve, 1 and 2 January 2019).

Figure C.5 South Australian Revenue duration curve, 1 and 2 January 2019



These averages are retained for each of the 365 days for subsequent ranking of the trading days from highest to lowest sell price. The next plot shows the average prices overlaid on the previous plot (Figure C.6 Highest and lowest average price periods in South Australia, 1 and 2 January 2019).

Figure C.6 Highest and lowest average price periods in South Australia, 1 and 2 January 2019



To declutter this plot, these averages are shown below along with the margin (Figure C.7 Margin between highest and lowest average price periods in South). The margin equals the high average sell price minus the low average fuel cost.

Figure C.7 Margin between highest and lowest average price periods in South Australia, 1 and 2 January 2019

As day 2 sell price exceeds day 1 sell price, day 2 would be preferentially traded. This process is repeated and then sorted by sell price (high to low) which gives a sequence of 365 days ranked highest to lowest, with paired buy prices (i.e. fuel costs) and margins for each day. The fuel costs are used in the LCOS algorithm and the averaged sell prices are used in the RDC curve construction.

Appendix D: Calculated Construction Cost Comparison

The below table lists some contemporary project costs for comparison with our cost estimates.

Table 1 Construction costs of battery storage projects commissioned since last report, compared to cost estimates.

Site (Lithium-Ion)	Victorian Big Battery[17]	Wandoan South BESS[18]	Wallgrove BESS[19]
MW	360	50	50
Low Cost (AUD $m)	$151.2	$64.4	$55.4
High Cost (AUD $m)	$274.9	$111.2	$73.4
Reported Cost (AUD $m)	$160	$120	$65.5

17 CEFC, Victoria gets 300MW big battery, 2021

18 Vena Energy Australia, Wandoan South BESS. 2022

19 ARENA, TransGrid Wallgrove Battery, 2022