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Review of alternative methods for extending LCOE to include balancing costs

Towards a method which can be included in the GenCost project

Paul Graham
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Copyright

Important disclaimer

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Acknowledgments

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Executive summary

A broad range of stakeholders require easily comparable cost data for electricity generation technologies. Levelised Cost of Electricity (LCOE) is the current best method but all stakeholders understand that this is no longer appropriate for a number of reasons. The primary concern[1] that this report is seeking to find a solution for is in regard to the inability of LCOE to capture the additional balancing costs that variable renewable electricity generation technologies are expected to increasingly require to ensure the electricity system has reliable and stable supply. We begin by considering whether it is possible and desirable to fix LCOE, moving on to what the options are for extending LCOE to be more useful and accurate for technology comparison.

This report reviews seven published studies which are relevant in developing a method for taking account of balancing costs. The review applies a set of criteria which are the breadth of balancing solutions included, the capacity to recognise the context in which the renewables are being deployed, ability to draw conclusions about separate technologies as opposed to combinations and the transparency and repeatability of the method.

Although all of the studies are useful and in some cases provide some tools that that may be useful for other purposes, the review concludes that the requirement to be able to study the broadest range of balancing solutions in a variety of relevant contexts leads the solution towards the use of electricity system models.

The major disadvantage of using electricity system models is that they are not highly transparent and only repeatable by those with access to the required skills and licence fees. There are two types of models that could be used. The first option is to utilise commercial dispatch models. These models provide the highest confidence that the balancing solutions will be reliable in the context of the Australian National Electricity Market (NEM). The major disadvantage is that finding a least cost balancing solution may require a high number of iterations since dispatch models do not optimise the portfolio of solutions and generation expansion models are known to provide poor solutions due to their over-simplified time slicing.

The second option is to adapt or develop a hybrid dispatch and balancing solution portfolio optimisation model. This option has some risks in terms of achieving a model that solves in reasonable time but is not too low a resolution representation of the NEM. The key advantage is that the model should be able to achieve a high degree of automation. It also optimises the operation of storage devices included. The optimisation model is currently preferred. Another choice open to stakeholder input is whether the model should be open source[2] or not.

[1] An example of another concern is that it is becoming more difficult to justifying applying the same weighted average cost of capital to technologies with very different climate policy risks. There are a range of solutions for this issue ranging from the simple (e.g. adding an arbitrary premium) to complex (e.g. adjusting costs by a probability density function of carbon prices). A universally accepted approach has yet to be agreed.

[2] This means that equations, code and full data and software implementation are published on the internet. However, this still might require access to the software interface (although at a fraction of the cost of a full commercial dispatch model).

Part I Review of alternative methods

Towards a method which can be used for the GenCost project

In this section we describe the objectives of the review and apply evaluation criteria to seven different approaches which have been selected for their relevance to the GenCost project needs. We also discuss two additional methods which are variants of one of the main seven.

For the GenCost project our expectation is that we need to select an approach for calculating balancing costs that can be broadly understood by all stakeholders, is accurate in the sense that it does not under or overestimate costs through errors of omission or method, produces a metric that is similar to an LCOE and can be re-created or repeated by other organisations (ideally is not a restricted or proprietary tool). Some of these objectives are at cross purposes. For example, ensuring that the tool is accurate may require a level of complexity which does not lend itself to being easily understood or repeatable. After reviewing the existing methods in Part I, we provide options for addressing the trade-off between different approaches in Part II.

1 Introduction

1.1 The case for fixing LCOE and the vision for its extension

For those individuals and organisations who are familiar with the workings of electricity market models, and who maybe have access to their own, maintaining a cost comparison method like Levelised Cost of Electricity (LCOE) is probably not a high priority. Whether extended or not, LCOE will always be a simplification of the expected financial performance of alternative electricity generation technologies relative to what a full market simulation reveals.

However, for the much larger community of non-modeller electricity industry stakeholders who want to understand why electricity models give the results that they do, or why investors are making certain technology choices, an LCOE measure is considered a very useful short cut.

Without LCOE it is difficult to compare technologies without using sophisticated models and the results of those electricity market models become more of a “black box”, to be taken on trust, to non-practitioner audiences (noting most practitioners do undertake some level of validation). This heavy reliance on a small number of practitioners is not a good outcome for either party and so it is perhaps in the best interest of all that we still have access to a more broadly available short hand cost comparison measure.

Ideally we want a source of comparable technology data, updated regularly that can be understood at a glance. LCOE has performed that role in the past but needs to be extended in light of the greater emphasis on variable renewables in the electricity system and their additional balancing costs which are not captured by LCOE calculations.

To be clear, LCOE has always been applied to technologies that perform different roles, none of which on their own are designed to provide firm electricity supply under all circumstances. For example, base load technologies are not designed for rapid load following. One could apply LCOE in its current method and make comparisons only within specific categories of supply e.g. baseload, load following, variable. However, this approach falls down on two counts. Firstly, the electricity market could be satisfied with multiple combinations of each supply category, so eventually we are forced to compare costs across categories in order to understand what the information means for the market and LCOE doesn’t provide enough information to do this. Secondly, the ability to combine renewables and storage means that renewables could potentially participate across other non-variable categories of supply making the concept of distinct categories invalid.

Another consideration is that, in regions with low variable renewable uptake, it is likely that the current system can absorb variable renewables using existing balancing capacity. As such the LCOE may not be misleading at all in those regions at present (or no more than it has always been for all technologies). However, as the share of variable renewables rise, which is a high expectation given their continuing cost reduction, LCOE is expected to become increasingly less useful as a comparative measure and as an indicator of electricity prices as more balancing capacity will need to be added alongside variable renewables for system reliability purposes.

Another concern in regard to LCOE is that it is becoming more difficult to justify applying the same weighted average cost of capital to technologies with very different climate policy risks. There are a range of solutions for this issue ranging from the simple (e.g. adding an arbitrary premium) to complex (e.g. adjusting costs by a probability density function of carbon prices). A universally accepted approach has yet to be agreed.

In this report we are confining the problem to how to extend LCOE by including the additional costs of balancing renewables. The aim of the GenCost project is to be able to provide an extension to the LCOE calculation which takes into account balancing costs. Balancing costs are not strictly defined. In broad terms balancing costs are about how system demand is met from a combination of technologies with a given amount of reliability but can include other system services that support stability. Some technologies will require a different combination of balancing technologies due to their inherent qualities. We take the approach that the amount of balancing required is context dependent as we will discuss further below.

Ideally, the solution, should simply stack an additional amount onto the existing LCOE calculation (Figure 1-1). Calculating that amount will involve calculating the optimal amount of additional balancing solutions and their costs. The focus here is to determine the most accurate and efficient new method to carry out that task.

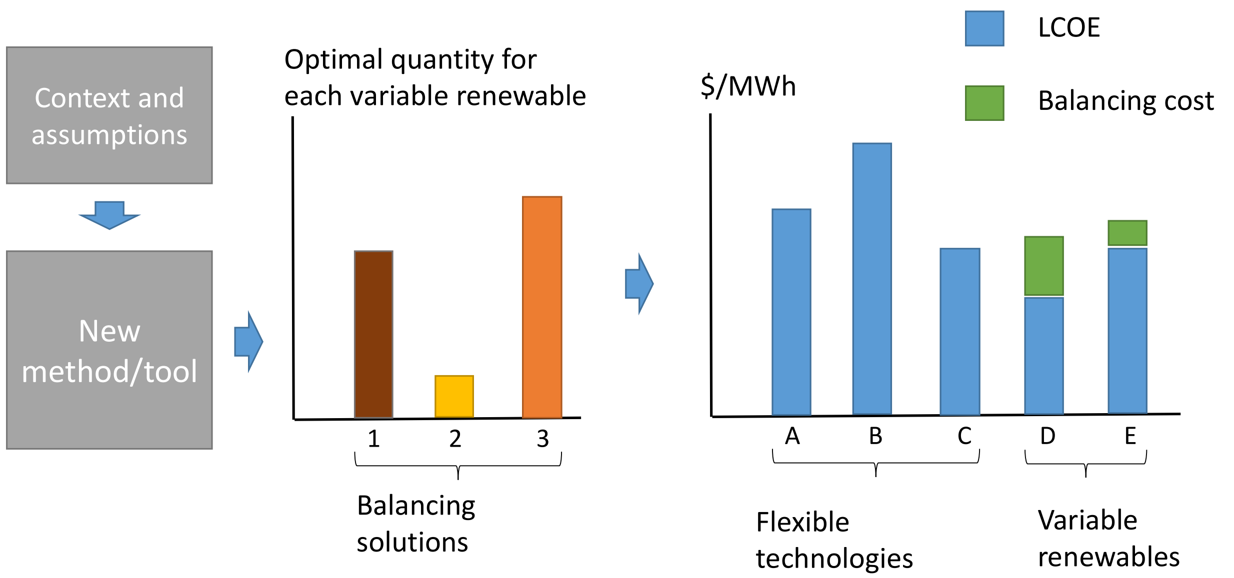

Figure 1-1: Vision for extending LCOE

1.2 Identifying techniques we can borrow or adapt to extend LCOE

For each of the items from the available literature included we summarise why we think the study has methods which are relevant, the calculation approach taken and any concerns about the methods in terms of being able to be adopted for the purposes of the GenCost project. Each of the studies included were developed for their own purposes which differ from that here but we only review the work for our own needs.

Beyond the broad objective of including balancing costs there are other criteria which will be considered during each method evaluation:

- **Breadth of balancing solutions considered**: We are interested in the least cost method of balancing. To be confident the solution is least cost it must include the widest possible set of solutions.
- **Context**: The cost of balancing depends on how much balancing is needed which means that context is important. A desirable method should recognise context. Not recognising context could mean that a method of calculating the cost of balancing is over or underestimated for a given location, time period or circumstance. Since balancing requirement is a system property we cannot ignore that a system may already have some existing balancing capacity. Existing balancing capacity should not be duplicated in calculating the cost of balancing a particular technology or combination of technologies (i.e. this would be an overestimate of costs).On the other hand existing capacity may retire and therefore we should be mindful that costs may change over time (i.e. time is an important context)
- **Transparency and repeatability**: The more complex a method becomes in terms of requiring complex or proprietary models the less transparent and repeatable will be the method. Ideally a method would be available in an open source modelling framework
- **Technology specificity**: Balancing costs are a system property whereas conventional LCOEs are a technology property. Ideally a method should include a way of referring the system costs back to a specific technology.

2 Review #1: ITP study for ARENA

2.1 Basic data

Full reference

The report and related Excel files are available for download. We reference this work by identifying all authors. However, the work is referred to as the ITP study for brevity. ITP is the organisational affiliation of the lead author.

Lovegrove, K., James, G., Leitch, D., Milczarek A., Ngo, A., Rutovitz, J., Watt, M. and Wyder, J. 2018a, *Comparison of dispatchable renewable electricity options: Technologies for an orderly transition*, Australian Renewable Energy Agency, Canberra, https://arena.gov.au/projects/comparison-of-dispatchable-renewable-electricity-options/.

Lovegrove, K., James, G., Leitch, D., Milczarek A., Ngo, A., Rutovitz, J., Watt, M. and Wyder, J. 2018b, *Levelised cost calculator*, Australian Renewable Energy Agency, Canberra, https://arena.gov.au/projects/comparison-of-dispatchable-renewable-electricity-options/.

Funding body

ARENA

2.2 Overview

2.2.1 Relevance

The report proposes a new metric which provides insights into the costs of dispatching renewables and storage systems which is relevant for the problem of balancing renewables. Specifically it proposes a method for calculating the cost of electricity on the basis of a given matching the right amount of variable renewable capacity to storage, to achieve a minimum LCOE for a defined amount of hours of dispatchable generation.

In their own words:

> *This study uses LCOE to compare dispatchable renewable options where the LCOE is presented as a function of the hours of stored energy (for solar or wind inputs) or the hours of delivery per day (for bioenergy or geothermal systems) that is achieved*

The report also clarifies some concepts with regard to how to include the cost of the different power and energy technology components at different scales.

This analysis seeks to find LCOEs for dispatchable generation solutions that can provide the balancing variable renewables. It does not examine how much of that would be required to provide sufficient balancing.

2.2.2 Calculation approach

For variable renewables, the method optimises the amount of renewable capacity that minimises LCOE for given amounts of storage capacity in hours using an hourly model of variable renewable electricity supply for a year of historical data (in this case New South Wales variable renewable output profiles). This amounts to trialling alternative ratios of storage to renewable capacity to find the one with the lowest cost. Storage is assumed to be preferentially charged (as opposed to output being sent to the grid) and discharge is assumed to occur at a set time consistent with meeting the target number of hours.

Note that, the amount of variable renewables assumed to be required for the charging of storage is smaller than the total amount of renewable generation that is delivered when combined with the storage technology.

For flexible renewable energy generation, the hours of storage target was used as the assumption for the hours of output per day (i.e. determined their capacity factor).

2.3 Evaluation against criteria

2.3.1 Breadth of balancing solutions considered

Aside from flexible renewables, storage is the main balancing technology considered for variable renewables. The potential use of demand management and oversizing of variable renewables was discussed but not included formally in the least cost optimisation.

The capacity of existing balancing capability in the system or the ability of the transmission system to connect to additional balancing resources were not considered since this was not a system analysis. As such this method is not considered least cost for the broader concept of balancing variable renewables in a system.

2.3.2 Inclusion of context

Given this is not a system study, the main element of missing context in this approach is that it does not recognise existing flexible generation in the system and how this impacts the need for balancing costs. Under the method, any hour per day of balancing that is required is always achieved by building new dispatchable renewable and storage capacity, whether the system can already provide that balancing by other means or not. As such, the results from this method are more relevant for the long term when existing balancing capacity may be retired or in South Australia where substantial retirements have already taken place. At present, beyond South Australia, storage capacity may not be immediately required. Even in South Australia, we do not know how many dispatchable hours and subsequent storage capacity are relevant.

Another context limitation is that the report only used New South Wales solar and wind data, however the method could be applied to other locations where data is available.

2.3.3 Transparency and repeatability

No specific equations or working are provided. However, this method would be reasonably amenable to replicating in an open source format due to its moderate level of complexity. An Excel file format that is to be made available for download won't be able to re-optimise storage and renewable capacity ratios but will allow users to change input assumptions.

2.3.4 Technology specificity

This method is able to provide individual assessment of the costs of technology-storage combinations such as "Utility PV/Batt", "Utility PV/PHES", Utility PV/H2", "Wind/Batt", etc as well as standalone technologies such as solar thermal with storage, biomass and geothermal. They also calculate the cost of a combined solar and wind farm output called Grid VRE with storage.

2.3.5 Other issues

The use of the number of dispatchable hours per day to set the capacity factor for biomass and geothermal could be misleading to some audiences. However, the reason this approach is taken is because the report is interested in their ability to support variability. Were this not the focus, for technologies that are not cost constrained in their ability to provide firm power, the hours per day that maximise capital utilisation would be the main concern. The higher hours per day (20 and above) are probably the only relevant outputs for geothermal given near zero operating costs. However, some biomass plants might be constrained by feedstock inputs to lower daily utilisations. To get the best financial returns from biomass inputs, the report finds that, as the share of variable renewables increases, it might make sense to build digesters and additional biogas storage capability configured to supply the power block of a gas peaking plant.

2.4 Brief note on IRENA's Electricity storage cost-of-service tool

Full reference

The tool may be downloaded from:

http://www.irena.org/publications/2017/Oct/Electricity-storage-and-renewables-costs-and-markets

Sources of data and additional technical description of the tool (including equations in Annex 2) are available in the following publication:

IRENA (2017), *Electricity Storage and Renewables: Costs and Markets to 2030*, International Renewable Energy Agency, Abu Dhabi.

Relevance and differences to ITP's study

IRENA has provided a spreadsheet tool which calculates the cost of storage in providing a range of services. It includes a wider range of storage technologies than the ITP study, including compressed air energy storage and flywheels, for example. Rather than providing a continuum of costs as a function of hours of operation as in the ITP study, IRENA provide 12 different applications which are defined by differences in scale, energy to power ratio, cycles per day and electricity prices. The tool is flexible enough that users can define their own applications using these four parameters to create customised results. For the purposes of this report, this feature of the tool means it might be possible to define balancing renewables as a set of new applications (using these four parameters) and use the tool to calculate the cost of using the different storage options to achieve the applications. This approach would require a separate or add-on tool[3] to define the variable renewables balancing application needs and condense those needs into the four parameters.

The common point with the ITP study is that the focus is on storage and consequently, using this tool would have the same “breadth of balancing solutions considered” limitations. A key difference is that the IRENA storage cost tool requires the user to either select or define the need/application before calculating the cost of the storage. This could be considered superior to ITP’s approach in the sense that no application is defined in the ITP study and so it was not clear how to interpret when and where the identified costs of storage in hours should be applied. On the other hand the IRENA storage cost tool doesn’t have a specific variable renewables balancing application. Existing tool applications such as “energy shifting” and “peak shaving” are relevant in this context but represent specific contexts that may be too narrow. Further applications would need to be defined as already discussed.

A second key difference is that IRENA provide this tool as a publicly downloadable Excel file and it therefore has a higher degree of transparency and repeatability than the ITP study[4]. On the other hand, it is performing a relatively simple task. The energy to power ratio of the storage options are not optimised in the IRENA tool but relate back to the selected application.

[3] This tool would need to simulate the gap between demand renewable output and the operation of existing flexible generation and so would be an electricity market model or something similar.

[4] However, the authors of this study have indicated they are likely to release a spreadsheet in due course.

3 Review #2: The MEGS report

3.1 Basic data

Full reference

Boston, A., Bongers, G., Byrom, S. and Staffell, I. 2017, *Managing Flexibility Whilst Decarbonising Electricity - the Australian NEM is changing*, Gamma Energy Technology P/L, Brisbane, Australia

Funding body

Australian National Low Emissions Coal Research and Development (ANLEC R&D). ANLEC R&D is supported by Australian Coal Association Low Emissions Technology Limited and the Australian Government through the Clean Energy Initiative.

3.2 Overview

3.2.1 Relevance

Boston et al (2017) provide a new approach for including the balancing cost of renewables both in terms of reliable supply and system stability. These are both addressed by using a NEM dispatch simulation model which explicitly includes the existing NEM reliability of standard for 0.002% unserved energy and a hard minimum constraint on inertia as a proxy for system strength and stability.

As with other reports reviewed the authors did not set out to make a contribution to extending LCOE, but rather to create something separate and more useful.

3.2.2 Calculation approach

The analysis is conducting using a model called MEGS – Modelling Energy and Grid Services. This model is similar to a UK model called BERIC (Balancing Energy, Reserve, Inertia and Capacity). While no equations are provided, from the verbal description in the appendix the core of the model is a fairly standard electricity system dispatch cost minimisation problem which mimics the dispatch system for the NEM itself (we will call this a dispatch model for short).

Relative to other commercial dispatch models, some key differences in this dispatch model are:

- There is an explicit hard inertia constraint for each state
- Only a single demand year is included in the sense that the model has not included new demand data (from a load or energy perspective) when exploring future years. However, were such data or the time to develop data available to the authors there doesn't appear to be anything inherent in the approach that would prevent it from including future demand projections. The selection of the weather year was most concerned with selecting

a representative weather year from 10 years of data using an analysis tool customised for such purposes.

- To reduce computation time, the model steps forward every 2.5 hours (rather than half hourly[5] or hourly). Note, the next point implies that each day may be solved as a set of interdependent sequential points.
- Storage technologies (batteries and hydro) must balance all charging and discharging in a single day – there are no multi-day/week/season storage management strategies (this is probably the most unrealistic for hydro)
- Most dispatch models link with a longer term generation capacity expansion model to determine the capacity available in the simulation year. Boston et al. (2017) instead describe a procedure whereby they add low emissions technologies and remove existing capacity to achieve a given emission level (including a subsidy for low emissions technologies to ensure they are dispatched to proxy the effect of emission reduction policies). This approach is possibly more input driven than others. The more traditional approach is used when future scenarios, including the Finkel review technology set are applied.

In regard to the inertia constraint, only existing rotating plant were allowed to provide it. Synchronous condensers and new pumped hydro were not included.

3.3 Evaluation against criteria

3.3.1 Breadth of balancing solutions considered

The discussion on page 9 and 10 implies that battery storage was considered the only solution for covering long periods of low renewable outputs described as a renewables "drought"(with the text highlighting that within five years each state experiences a 9 day "drought"). Battery storage is a suboptimal solution for delivering long periods of energy output. Other types of storage or gas peakers would likely delivery lower costs for this type of need. Later in the report, a 2050 case study does allow OCGT to contribute and is found to assist in reducing system costs. The modelling approach does not require that only battery storage is included so this is something that could likely be addressed with modest effort.

Interconnections between states are considered and reduce the length of renewable "droughts" and sensitivity analysis indicates additional transmission capacity could reduce system costs under high renewable shares.

3.3.2 Inclusion of context

System costs are presented on the basis of different contexts, primarily the amount of emissions reduction that can be achieved from different technology mixes relative to 2017 as well as 2030

[5] This was user defined rather than an inherent limitation in the model. Half hourly mode is available.

and 2050 case studies which also explore alternative technology mixes. However, the modelling system is flexible enough in that it would also be able to provide other contexts such as the costs for different state regions, future time periods and shares of different technologies (rather than the abatement they achieve).

3.3.3 Transparency and repeatability

While the appendix of the report provides a summary of the modelling framework, there does not appear to be any publicly available documentation in terms of equations or data for either the MEGS or BERIC models. It is therefore assumed these are proprietary models (i.e. owned by the authors with their details not published due to the commercial value of the intellectual property). The public availability of the equations would help to solve some uncertainties we have identified in the modelling approach (e.g. lack of detail on the set of technologies that can contribute to meeting the inertia constraint).

3.3.4 Technology specificity

The modelling outputs are presented as system costs that relate to scenarios which include the choice of abating emissions either by adding more renewables (solar photovoltaics and wind), more combined cycle gas or more coal with CCS. It would be possible under this framework to break out renewables further by adding one of each renewable independently rather than as a mix.

3.3.5 Other issues

The modelling reports that 4hrs of storage at 10% of renewables capacity was built. It is unclear why this ratio was chosen or why it did not change as the share of renewables changed. With this ratio fixed, it appears the MEGS framework relied more heavily on oversizing renewable capacity to ensure sufficient energy during low renewable output periods (comments elsewhere in the report suggest high renewable curtailment in high energy periods).

The approach of assigning a fixed ratio of batteries to renewables may also explain comments earlier in the report which finds renewables immediately add costs to the electricity system at any scale. It is difficult to reconcile this approach to the fact that renewables have been added to the system for the last decade without storage and with system costs not changing significantly until the last few years (which relates to a number of new factors, such as retirement of fully amortised plant and higher gas prices, rather than simply a rising renewable share).

4 Review #3: Levelised Avoided Cost of Electricity (LACE)

4.1 Basic data

Full reference

EIA (Energy Information Administration) 2013, *Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement*, US DOE.

For recent results, see

EIA (Energy Information Administration) 2018, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2018*, US DOE.

Funding body

United States Department of Energy

4.2 Overview

4.2.1 Relevance

The EIA's levelised avoided cost of electricity (LACE) is included in this review because it is a concept that indirectly indicates how LCOE can be adjusted for balancing costs by taking into account the different operating times and capacity at peak of technologies. LACE calculates the potential revenue available to the project owner for a given technology reflective of its ability to provide both energy and capacity into selected representative periods of each season a year. The energy value is a weighted average of the marginal cost of electricity dispatch during the selected periods, further weighted by the number of hours of assumed operation in each time period. The capacity value is the marginal cost of meeting system planning reserves weighted by the estimated capacity credit for each technology. Definitions and details are provided below under the calculation approach discussion.

This approach captures the balancing costs of renewables in two ways. The first is that as more variable renewables supply electricity to a particular time period the lower will be the marginal generation price during that time period and therefore the lower the revenue it can receive. Conversely, flexible technologies are likely to receive higher prices in periods when variable renewables are not operating due to a tighter market. To some extent, this approach provides a formula for valuing the amount of diversity and flexibility in energy provision. It also calculates the value of the capacity of flexible and variable renewables at peak time, with the latter being lower and receiving a lower capacity payment component.

EIA propose that each technology has its LCOE and LACE calculated and that if the LACE value is lower this indicates that the market does not value that technology and it should not be built even though its LCOE may be relatively low. Conversely, a low LACE value but high LCOE is indicating that the market is seeking capacity that suits that technology's energy and capacity capabilities. To put it another way, net economic value=LACE-LCOE. If net economic value is negative then investment should not proceed and the LCOE is over-valuing the benefits of the technology to the system. If net economic value is positive then investment should proceed and LCOE is under valuing the technology to the electricity system. If net economic value is zero then investment can still proceed and LCOE s an accurate measure of the value of the technology to the electricity system.

4.2.2 Calculation approach

The formula for calculating LACE is published in EIA (2013) and is reproduced here including the following definitions:

$$LACE = \frac{\sum_{t=1}^{Y}(marginal\ generation\ price_t * dispatched\ hou\quad _t) + (cap\ payment * cap\ credit)}{annual\ expected\ generation\ hours}$$

Where:

***LACE** is the levelized avoided cost of electricity, expressed in units of $/MWh.*

***t** is the time period and **Y** is the number of time periods in the year. NEMS represents nine time periods for electricity capacity planning purposes; each of the three seasons of the year (winter, summer, and fall/spring) includes a representation of peak hours, intermediate hours, and off-peak hours. The summation is performed for all of the periods in the year.*

***Marginal generation price** is the cost of serving load to meet the demand in the specified time period. This price is typically determined by the variable cost (fuel cost plus variable O&M) of the most expensive generating unit that needs to be dispatched to meet energy demand. This price may also be impacted by the cost of meeting any environmental or portfolio policy requirements by the marginal generators (that is, the cost of purchasing renewable energy credits for a non-qualifying generator).*

***Dispatched hours** is the estimated number of hours in the time period the unit is dispatched. This number is consistent with the utilization parameters assumed for the LCOE calculation.*

***Capacity payment** is the value to the system of meeting the reliability reserve margin. It is determined as the payment that would be required to incentivize the last unit of capacity needed to satisfy a regional reliability reserve requirement.*

***Capacity credit** is the ability of the unit to provide system reliability reserves. For dispatchable units, the entire nameplate capacity is allowed to participate in the reliability capacity market (capacity credit of 1 or 100%). For intermittent renewables, the capacity credit is derated as a function of the availability of the resource during peak load periods and the estimated probability of correlated resource-derived outages within a given region. For example, the capacity credit is the probability that if the wind is not blowing in on part of the region, it is or isn't blowing in a different part of the region.*

__Annual expected generation hours__ are the number of hours in a year that the plant is assumed to operate; the derivation is identical to that described in the LCOE section above.

The marginal generation price is sourced from the EIA's National Energy Modelling System (NEMS) which includes an electricity module. The electricity module includes 9 time slices per year: Sumer, Winter and Spring/Autumn by Daytime, Nighttime and Shoulder.

Based on a worked example provided by EIA (2013), the dispatched hours is essentially the average annual capacity factor for a flexible plant, but for variable renewables depends on average output across a region for a given weather year during the selected representative time periods. The annual expected generation hours is the average annual capacity factor. The capacity credit is the expected output at peak demand with might be 100% for flexible plant but for variable renewable plant will be the average output across a region for a given weather year during peak times. The capacity payment is the fixed annual operating costs of a gas peaking plant – the logic being that this is the cost of capacity avoided.

4.3 Evaluation against criteria

4.3.1 Breadth of balancing solutions considered

LACE considers balancing solutions to the extent that the EIA National Energy Modelling System includes them in its electricity modelling. For example, if the generation price during the Daytime time slice is not too low, that might indicate that NEMS has deployed storage. We have chosen not to review the current NEMS technology mix. The relevant point is that this method is able to include a broad range of solutions within the NEMS system and reflect those in the LACE calculation formula as different marginal costs of generation at different time periods

4.3.2 Inclusion of context

LACE can be calculated for each year and region and for a number of alternative renewable share and greenhouse gas abatement scenarios. Various government policies may impact the generator price and therefore the LACE calculation.

4.3.3 Transparency and repeatability

The equation for calculating LACE is highly transparent. It could be repeatable if EIA published all input data. However, if all input data is not published then only those with access to NEMS can calculate the LACE for United States technologies. For Australian analysis we would need access to an Australian adapted NEMS or an Australia model which produces the required outputs. The key outputs are generation prices are different representative times of the day and year and consistent data for the amount of generation from each technology at those times of year. Most Australian electricity models do produce this data. As such the repeatability of this method would be limited to those organisations with electricity models.

4.3.4 Technology specificity

LACE has the same technology specificity as LCOE. It can be calculated for each individual technology independent of the balancing solution.

4.3.5 Other issues

Interpretation

A key question for this method is whether it actually gets to the heart of measuring the balancing costs and whether the calculated LACE can be interpreted in a straightforward way. In theory if an electricity system does not value variable renewable technologies (or to put it another way is showing low generator prices for the periods where it is producing output) then the LACE value will be low. However, this low LACE value could represent several things occurring in the market. The first is the market might have a lot of excess capacity causing low prices (which could also imply a lot of balancing capacity if the excess capacity is flexible). Another is it might indicate a lack of balancing capacity. For example, if a significant amount of non-diverse renewables have been deployed without storage we would find low prices in time periods where their generation is highly coincident. Conversely a high LACE value for variable renewable technologies could indicate a tight supply market, or one with strong emission taxes or a market where adequate balancing capacity has been deployed in the time periods when variable renewables operate and hence additional balancing costs are low.

This potential for mixed messages around what the LACE calculation is saying about additional balancing costs versus other market supply-demand and policy factors that are impacting the electricity generation price is problematic from the point of view of clarity of message.

In theory, we could construct experiments using an electricity model and LACE calculation whereby we remove the influence of other factors such as demand and capacity imbalances and policies and search for levels of balancing for each technology that result in the highest possible LACE value. If LACE values were found that met or exceeded the LCOE, this would indicate the level of balancing required so that investment in that technology should proceed. This would be useful in itself. However, the LACE value can’t be directly interpreted as an LCOE with the addition of balancing costs to be compared with other technologies. We could instead take the average generation price from the electricity model as an indicator. However, this makes the LACE calculation somewhat redundant.

The LACE formula

The use of the fixed operating and maintenance costs of gas peaking plant as the value of capacity at peak seems somewhat limited. With the potential for storage to replace some of the roles of gas peakers, this assumption for the capacity payment would need to be reviewed.

4.4 Brief note on AER's LCOE working paper

Full reference

Australian Energy Regulator (AER) 2018, *Wholesale electricity market performance monitoring: Staff working paper on 2018 approach to LCOE analysis*, AER, Australia.

Relevance and differences to LACE

The AER's 2018 working paper is relevant here under the LACE method because it shares some common objectives and approaches. For the purposes of monitoring electricity system performance the Aer would like to know whether new entrants who would appear to be competitive are being prevented from entering the market by other barriers. The method for assessing whether technologies are competitive compares the LCOE for each technology by the percentage of hours a year they operate with price and revenue duration curves. The price duration curve (PDC) simply represents the percentage of the year that prices prevail while the revenue duration curve (RDC) is derived from the PDC and is the average revenue that is earned as a function of the percentage of hours of operation.

The EIA compares the LCOE to the LACE to determine whether investment in a technology can proceed from a financial point of view (if the LACE is greater than LCOE). The AER compares the LCOE and the RDC and concludes investment may be financially viable if the RDC exceeds the LCOE.

Compared to the RDC the LACE is more accurate as a measurement of financial viability since it directly matches the price periods with the times a plant is operating. The RDC is only useful as a measure of revenue for plant which are flexible enough to choose to operate in price periods ranked from highest to lowest. The lowest cost renewables have no such capability. However, the RDC can be calculated from readily available market data, whereas the LACE requires access to an electricity model.

5 Review #4: CSIRO electricity system modelling

5.1 Basic data

Full reference

The relevant model equations are presented in Appendix B of:

Campey, T., Bruce, S., Yankos, T., Hayward, J., Graham, P., Reedman, L., Brinsmead, T., Deverell, J. 2017 *Low Emissions Technology Roadmap: Technical report*. CSIRO, Australia. Report No. EP167885

https://www.csiro.au/en/Do-business/Futures/Reports/Low-Emissions-Technology-Roadmap

Funding body

The model was developed as an internal CSIRO strategic project but was refined further during the course of two projects:

Electricity Network Transformation Roadmap: co-funded by CSIRO and Energy Networks Australia

Low Emissions Technology Roadmap: funded by the Department of Energy and Environment

5.2 Overview

5.2.1 Relevance

In 2016-17 two projects required CSIRO to examine the cost, technology mix and greenhouse gas emissions associated with high renewable share (up to 100%) electricity generation for Australia. The challenge under these scenarios is to be able to provide the model with enough information so that it is correctly calculating unit costs, which are somewhat dependent on the technology mix, and selecting the least cost technology mix consistent with those unit costs. Electricity system modelling typically starts with a long-term generation expansion model which optimises investment simultaneously for all time periods over the planning period. Such models typically represent a year by using only a small number of time slices, each representing a relatively large proportion of the year. A major concern is whether such a coarse resolution for time periods can be used to adequately capture the operation of variable renewables and their supporting technologies such as storage. For example, time slicing representation that distinguishes both seasons of the year and hours of the day can be used to capture the average output of variable renewables in each of those time slices. However, it would not capture the fact that once in every 5 to 10 years there could be a continuous period of a week or weeks when renewable output is very low. Furthermore, different storage technologies are appropriate for different storage time scales (hours, days, seasonal).

To provide more confidence that the costs associated with managing variable renewables were being captured within a long term electricity generation investment model, CSIRO constructed an additional model at a faster time scale and shorter time horizon, which minimises the cost of meeting electricity demand for each half hour of one year. This faster time scale model selected the least cost combination of the mix of renewables, storage and non-renewables such as peaking gas to ensure that a particular renewable share was met. In effect, this model calculated the balancing costs for any given share of variable renewables. Equivalent balancing costs were imposed back on the longer term electricity generation expansion model to ensure total system costs included all balancing costs.

5.2.2 Calculation approach

A cost minimisation problem was solved for each state independently and included the equivalent annualised capital cost of generation and storage technologies. It is important to note that the fast time scale optimisation problem was not solved sequentially each time step but simultaneously for all half hours for a full year. As a result, owners of storage had effectively perfect foresight about future (weather driven) demand and supply conditions and adjusted their charging and discharging decision accordingly to minimise costs for the system.

Modelled constraints included the need for supply to meet demand in each half hour, normal battery and generation plant operating constraints and a requirement for a minimum share of non-synchronous generation capacity. Electricity demand and the amount of remaining capacity of hydro and non-renewable plant in each state was also imposed on the fast time scale model as existing context, as projected by the electricity generation investment model. The model was solved for one year, at five-yearly time steps from 2020 to 2050 (that is, 2020, 2025, 2030… 2050).

As identified in the MEGS modelling, the selection of a representative weather and a consistent demand year is an important step. Ideally we should choose a typical year (if such a year exists), explore all available historical weather years, or make some adjustment to a selected year to account for extreme events. We chose the latter approach. In the ten-year renewable resource data available we selected the week with the lowest renewable output. We took this week of low renewable resource availability and inserted it in our selected weather year as a repeated three week event to make sure that the electricity system could continue to provide reliable supply through a worst case event that might be expected to occur in the 30 year planning period.

The three most significant simplifications made by the CSIRO model are the absence of inter-state interconnections, no ramp rate constraints on generation and no direct representation of the bidding and dispatch process (which is implied only, and assumes no gaming in bidder behaviour). Another simplification is that, like the MEGS model, technologies are represented as aggregate blocks of capacity, not individual plants. Were aspects of the model to be adjusted to include these additional characteristics then it would move towards replicating the behaviour of a commercial dispatch model with the exception of the forward looking behaviour associated with the minimisation of costs simultaneously over all time periods.

The outputs of the half-hourly generation and storage operations model include the costs and amounts of installed storage, reductions in variable renewable capacity factors due to curtailment, the generation share of different variable renewables and requirements for peaking gas or other synchronous generation.

5.3 Evaluation against criteria

5.3.1 Breadth of balancing solutions considered

The CSIRO model includes, of storage technologies, only battery and existing hydro storage and conventional synchronous generation. However, it would be relatively simple to widen these categories to include a broader set of storage technologies, such as solar thermal, and other devices for providing inertia.

The CSIRO model is not in a position to consider the role of inter-regional transmission in balancing renewables. This would require more substantial structural changes to the model.

5.3.2 Inclusion of context

System costs are presented on the basis of different contexts, primarily the scenarios relating to different levels of renewables penetrations in different years and in different state regions. The modelling system is flexible enough in that it could also represent other contexts such as specific targeted levels of greenhouse gas emissions or renewable energy mixes.

5.3.3 Transparency and repeatability

The published equations and some input data provide significant transparency. However, only a limited number of organisations would be capable of building the model from the equations into a software framework that would produce the model outputs. It does not reach the standard of providing equations, code and software.

5.3.4 Technology specificity

Technology specificity is an issue because the model is currently configured to select the least cost mix of renewables rather than focus on a particular renewables. However, new equations could be introduced into the model to force it to focus on one technology at a time and calculate the balancing costs associated with adding that technology to the electricity system.

5.3.5 Other issues

The appropriate extent of forward looking storage behaviour

The primary reason that the CSIRO model lacks some of the basic assumptions of an electricity dispatch model, such as state interconnection, is because of the decision to configure the costs minimisation problem to solve for all half hours within a year simultaneously. This makes the model too large to include all of the features of a dispatch model which only solves each half hour sequentially (making models solved sequentially a factor of 17,520 times smaller). The decision to solve each time period simultaneously was to ensure the model included forward looking behaviour. Forward looking behaviour is required to realistically simulate the behaviour of storage technologies. The decision to charge or discharge storage is fundamentally dependent on whether the current half hour is the most optimal period in which to take that action, which is dependent upon whether there are any better future periods in which to take that action. Given that weather forecasting is reasonably accurate over several days, we can assume that the storage owners will be able to predict future market conditions with reasonable accuracy and make decisions on that basis. Furthermore one would assume that hydro generation might consider seasonal rain forecasts in making decisions about charge and discharge rates.

However, while forward looking behaviour is necessary for storage operation modelling, a full year look ahead capability is probably neither realistic, nor an efficient use of computational power. It would be preferable to include more features of a dispatch model and reduce the computation resources requirements by shortening the decision time horizon to a day or days.

6 Review #5: NEMO

6.1 Basic data

Full reference

The National Electricity Market Optimiser has been published in several relevant report and papers:

Blakers, A., Lu, B. and Stocks, M. 2017, *100% renewable electricity in Australia*, ANU.

http://energy.anu.edu.au/files/100%25%20renewable%20electricity%20in%20Australia.pdf

Elliston, B., Diesendorf, M. and MacGill, I. 2012, Simulations of scenarios with 100% renewable electricity in the Australian National Electricity Market, *Energy Policy*, vol. 45, pp. 606-613.

Elliston, B., I. MacGill, and M. Diesendorf 2013, Least cost 100% renewable electricity scenarios in the Australian National Electricity Market, *Energy Policy*, vol. 59: pp. 270-282.

Elliston, B., J. Riesz, and L. MacGill 2016, What cost for more renewables? The incremental cost of renewable generation - An Australian National Electricity Market case study. *Renewable Energy*, vol. 95: pp. 127-139.

Funding body

The model was developed through funding provided by ARENA to the University of New South Wales. However, the first reference above indicates that the Australian National University had also invested in the model.

6.2 Overview

6.2.1 Relevance

NEMO represents a system modelling approach designed to discover the cost of high variable renewable share systems by considering what additional resources would be required to ensure the National Electricity market reliability standard is met.

It introduces two new concepts which are defined as follows:

- The Levelised Cost of Generation (LCOG) which is the weighted average cost of generation assuming no curtailment for all technologies that contributed to electricity generation during a given year. Costs are amortised according to the usual LCOE formula.
- The Levelised Cost of Balancing (LCOB) which includes all of the costs of storage, additional transmission for connecting diverse renewables, transmission losses storage round trip efficiency losses and variable renewable curtailment losses. These costs are amortised.

Subsequently an LCOE for the electricity system in that year is calculated as the sum of LCOG and LCOB.

6.2.2 Calculation approach

Like the CSIRO model and MEGS, NEMO simulates chronological time in a given year. It is more akin to the CSIRO model in that it aims to optimise the balancing solutions for high renewable shares. However, it takes an iterative optimisation approach rather than optimising all time periods simultaneously. That is, NEMO solves each hour in a year sequentially and at the end of each year reviews the outcome for gaps in reliability and reruns the year for improved solutions. This essentially represents an iterative search procedure which requires running a model many times compared to the alternative of running a model once that internally optimises the solution but at the cost of a much slower model solution process.

Key features and assumptions of the model include:

- Hourly time resolution but with samples years form 2006-2010
- 43 supply regions across the NEM
- A transmission expansion plan is imposed
- Peak demand and electricity generation is assumed to be constant in future years
- Reliability is assessed with and without demand management.

6.3 Evaluation against criteria

6.3.1 Breadth of balancing solutions considered

The Blakers (2017) version of NEMO includes pumped hydro energy storage, renewable diversification, demand management scenarios and a single transmission plan. In principle, a broader set of storage technologies, different scales of demand management, fossil fuel peaking plant and options for alternative transmission plans may be able to be included. However, it is unclear whether a large number of alternative variable renewable peaking solutions begins to erode the advantages of the iterative approach by making the set of solutions over which the iterations need to occur too large.

6.3.2 Inclusion of context

In most publications the key context explored is 100% renewable shares. However, the modelling system is flexible enough in that it would also be able to provide other contexts such as varying levels of greenhouse gas emissions or renewable energy mixes.

6.3.3 Transparency and repeatability

Elliston (2012) is most often cited as being the original source description of the model but does not provide equations, only a qualitative description. On the other hand, the entire model is provided as source code at https://nemo.ozlabs.org/ and runs on the open source Python platform. The open source approach is commendable. However, even with this approach, only a limited number of organisations would be capable of using the model to produce outputs.

6.3.4 Technology specificity

Technology specificity is an issue because the model is currently configured to select the least cost mix of renewables rather than focus on a particular renewable. However, new equations could be introduced into the model to force it to focus on one technology at a time and calculate the balancing costs associated with adding that technology to the electricity system.

6.3.5 Other issues

The appropriate extent of forward looking storage behaviour

Given that NEMO is a sequential dispatch model, it is unclear that storage behaviour is optimal. The main tool for controlling storage behaviour is placing storage providers in a merit order such that they are dispatched whenever they have available capacity and the price threshold has been met. In reality, storage providers will be more strategic, looking ahead beyond the current hour to consider when the higher price period may occur and how to get the most utilisation out of their investment over an entire day, week, season and year.

7 Review #6: Power system generation mix model

7.1 Basic data

Full reference

The Power System Generation Mix Model (PSGMM) is described on the following internet address and pdf document:

https://epc.com.au/index.php/nem-model/

https://epc.com.au/wp-content/uploads/2018/08/ReliableAffordableElectricPowerGeneration_Booklet.pdf

Funding body

The information states that the model was built by Electric Power Consulting (EPC) of which Robert Barr is the main employee. Additional contributing authors for the model are:

Barry Murphy, Former Chairman & CEO Caltex Australia

Dr Mark Ho, President Australian Nuclear Association

Martin H Thomas

Barrie Hill, Managing Director SMR Nuclear Technology Pty Ltd

7.2 Overview

7.2.1 Relevance

To some extent every model of the Australian electricity market is relevant to providing a system approach to extending calculations of the levelised cost of electricity. However, since this model is specifically marketed as providing both a Levelised Cost of Electricity (LCOE) and a System Levelised Cost of Electricity (SLCOE) it is included in this report. EPC define the SLCOE as:

> *The average cost of producing electric energy from the combination of generation technologies chosen for the entire system over its entire lifetime, discounted back to today at 6% per annum*

It is also stated that this includes costs for required expansions in transmission.

7.2.2 Calculation approach

Details on PSGMM are limited but it appears to be a NEM dispatch simulation which uses data from a single year (2018) for demand and variable renewable supply profiles. The generation mix is supplied by the user.

There are no transmission constraints or network losses and state demand appears to be stacked into a single NEM-wide demand profile. Storage technologies are given simple instructions: always charge if energy is available and not already full. Batteries charge first but are dispatched last. Pumped hydro is charged last and dispatched first.

Cost assumptions from AEMO's Integrated System Plan are used except that no future cost reductions for variable renewables and nuclear costs are based on their own estimates.

7.3 Evaluation against criteria

7.3.1 Breadth of balancing solutions considered

PSGMM includes pumped hydro, battery storage and renewable diversification. Demand management and transmission are not examined. In principle, a broader set of balancing solutions could be included but there is no method for optimising them. The approach relies on examining a number of user defined cases. More extensive iteration or optimisation is required to have any confidence the cases examined represent optimal mixes of balancing technologies. Where storage is included, its daily operation is not optimised but rather subject to simple, myopic rules.

7.3.2 Inclusion of context

The examples shown in the published material include the current NEM and various options for replacing coal as well as representations of the mix from AEMO's Integrated system plan in 2040 and a 100% renewables scenario (which is common to other studies e.g. NEMO, CSIRO). However, the modelling system is flexible enough in that it would also be able to provide other contexts such as varying levels of greenhouse gas emissions or renewable energy mixes.

7.3.3 Transparency and repeatability

The published material provides only limited detail about the model. There are no equations. The exact method for calculating the system levelised cost is not described in any further detail beyond the definition already provided above.

7.3.4 Technology specificity

Similar to other system approaches reviewed, technology specificity is an issue. However, the cases could be modified to focus on one technology at a time and calculate the balancing costs associated with adding that technology to the electricity system.

7.3.5 Other issues

The appropriate extent of forward looking storage behaviour

Given that PGMM is a sequential dispatch model storage behaviour is not optimised but is rather determined by simple rules which do not take account of the future state of the market. In reality storage providers will be more strategic, looking ahead beyond the current hour to consider when the higher price period may occur and how to get the most utilisation out of their investment over an entire day, week, season and year.

8 Review #7: Value adjusted levelised cost of electricity (VALCOE)

8.1 Basic data

Full reference

International Energy Agency (IEA) 2018, *World Energy Model: 2018 version*, IEA OECD, Paris.

https://www.iea.org/media/weowebsite/energymodel/WEM2018.pdf

Funding body

International Energy Agency

8.2 Overview

8.2.1 Relevance

The IEA have developed VALCOE as part of their latest version of their World Energy Model (WEM) which is used to deliver the 2018 *World Energy Outlook*. As the name suggests, the value-adjusted levelised cost of electricity (VALCOE) is an LCOE that has been adjusted to take account of the differences in value each technology provides to the electricity system (relative to the average).When new electricity generation capacity is needed in the WEM, the model makes its choice between different technology options on the basis of their regional value-adjusted levelised cost of electricity (VALCOE). This is an approach that is very different from most long term electricity planning models in Australia which select new generation based on intertemporal least cost optimisation which includes all cost elements (capital, fuel, O&M) separately and constrains selection of those technologies to meet a load curve which has been segmented to include a number of different "time slices" to represent load variability over the year. The choice of using VALCOE to select technologies likely reflects the need to simplify approaches when working at a global scale. However, each region has its own hourly model upon the calculation of VALCOE is based.

8.2.2 Calculation approach

The VALCOE makes three adjustments to LCOE: energy, value and flexibility. The value adjustments are calculated from outputs of an hourly electricity market model. The equation for calculating VALCOE is as follows:

$$VALCOE_x = LCOE_x + (E_x - \bar{E}) + (C_x - \bar{C}) + (F_x - \bar{F})$$

After LCOE, the second term is the energy adjustment (E) which is the difference between the output weighted revenue per MWh received by technology X and the output weighted average system revenue per MWh (i.e. the average price). The third term is the capacity adjustment (C) which is the difference between the capacity revenue received by technology X and the average system capacity revenue. The capacity revenue is calculated from the capacity payments per kilowatt divided by the operating hours of each technology. The fourth term is the flexibility adjustment (F) which is the difference between the flexibility value of technology X relative to the average flexibility. Whereas the second and third terms of the equation were calculated from model outputs (e.g. prices) and technology characteristics, the flexibility value is based on a flexibility value multiplier, which is user defined and constant over time. The flexibility multiplier is multiplied by a base flexibility value which is assumed to increase with rising variable renewable energy shares, up to a maximum equal to the full fixed capital recovery costs of a peaking plant.

8.3 Evaluation against criteria

8.3.1 Breadth of balancing solutions considered

In the hourly dispatch models applied in each region, the WEM allows for the optimal deployment of demand response and storage technologies for balancing purposes. The exact process for doing this is not clear but implies some iteration between exploring how large the gap is and then selecting from a menu of responses based on the pricing available during those gap times. It considers the greater need for transmission under increasing renewable shares but does not optimise the amount of transmission.

8.3.2 Inclusion of context

Being a global system modelling approach the WEM explores specific regional contexts, each year to 2040, inclusive of taking account of existing capacity and retirements. The World energy Outlook considers several scenarios.

8.3.3 Transparency and repeatability

The published material provides several equations for calculating the VALCOE in broad terms and an equation for each subcomponent (the energy, capacity and flexibility values). However, the data for several of the variables in these equations must be inputted from the WEM regional hourly dispatch models. No documentation or equations is provided for this model. While the basic equations of a standard dispatch model are fairly well known, the WEM dispatch model has two non-standard features - capacity constraints and also some type of iterative procedure for selecting demand response and storage capacity. Outside of this model, the flexibility value in the VALCOE equation also requires some user input and is poorly defined.

8.3.4 Technology specificity

This approach provides a unique VALCOE for each technology. And indeed, in the WEM, the VALCOE is directly used to select the type of technology that will be deployed to meet electricity demand growth or replace retiring plant.

8.3.5 Other issues

How to interpret VALCOE

The IEA developed VALCOE for their own particular purpose (to guide investment decisions in a multi-regional global electricity model) but our purposes here is to understand whether it might be applicable to creating a technology comparison metric. VALCOE awards extra value (removes value) relative to the standard LCOE if a technology provides more (less) of three electricity services (energy, capacity and flexibility) than the average. This does appear to be a good comparison metric in that it defines the services that are of value and adjusts LCOE so that the relative ability to provide those services is taken into account.

The value of VALCOE itself does not reveal any insights beyond its use to create relative rankings. It is not a cost measure, nor net-revenue. It is cost adjusted by differences in value/revenue which has no intrinsic interpretive value than for comparison purposes.

A final interpretive issue is that the VALCOE formula assumes the electricity dispatch system has a capacity market which is true for Western Australia but not for the National Electricity Market (NEM). The IEA point out that they understand such markets do not exist in all regions but that this abstraction is necessary to discover the value of capacity. This is a reasonable approach in a global regional model but might represent an area for misunderstanding if implemented in an Australian adaptation of the approach. Model results would be impacted by the inclusion of a capacity constraint and diverge from observable NEM behaviour.

9 Summary of review evaluation

Table 9-1 provides an overview of how each of the methods review scored against the criteria. The legend for the table is as follows:

- Leading but not necessarily perfect – Blue/High
- Falling short but with some options for improving – Green/Medium
- Missing a crucial element and not easily fixed – Yellow/Low.

In comparing these methods it should be remembered that they were not necessarily designed with our purpose in mind and therefore these ratings are not a judgement on the quality of the work which in most cases was designed for a different but related purpose in mind. They have been artificially brought together in this review and compared because of their relevance.

Table 9-1: Summary of evaluation of methods for including balancing costs against selected criteria

Criteria	ITP	MEGS	LACE	CSIRO	NEMO	PGSMM	VALCOE
Breadth of balancing solutions considered	Low	Medium	Medium	Low /Medium	Medium	Low/ Medium	Low/ Medium
Context	Low	High	Medium	High	High	High	High
Transparency	Medium	Low	High	High	High	Low	High
Repeatability	Low/Medium	Low	Low/ Medium	Low/ Medium	Low/ Medium	Low	Low
Technology specificity	High	Medium	High	Medium	Medium	Medium	High

To summarise the MEGS, LACE, NEMO, PGSMM, VALCOE and CSIRO methods are generally capable of including a broad range of variable renewable balancing solutions while the ITP work is only designed to consider storage technologies or dispatchable renewables. CSIRO's model and the WEM regional models underlying VALCOE would require significant work to include transmission.

The CSIRO, MEGS, NEMO, PGSMM, VALCOE and LACE frameworks include system models and can therefore include a broad range of contexts. However, the LACE approach includes a US energy system model and would need to be adapted or replaced to be relevant to Australia. Under the VALCOE approach, Australia is not represented as a separate world region and is therefore too high level. However, the approach could be adapted to be applied in an Australian model. MEGS and PGSMM lack future data on demand but there is no limitation in their framework if data is available to them. The ITP framework does not include any representation of the application of technologies to the electricity system and therefore we cannot be confident the identified balancing costs are necessary.

The CSIRO, VALCOE and LACE frameworks provide details of equations used which, given the complexity of this topic, is very important to ensure the method is fully understood. While ITP does not provide equations the method is simple enough that the uncertainty is low. The MEGS framework is complex and only explained at a high level. NEMO is provided as source code but the underlying equations are less easy to follow for those not familiar with that code. Organisations with access to experienced personnel and modelling systems could likely repeat or recreate the ITP, NEMO, LACE and CSIRO methods. However, this would be a relatively small group compared to those who might want to access this material.

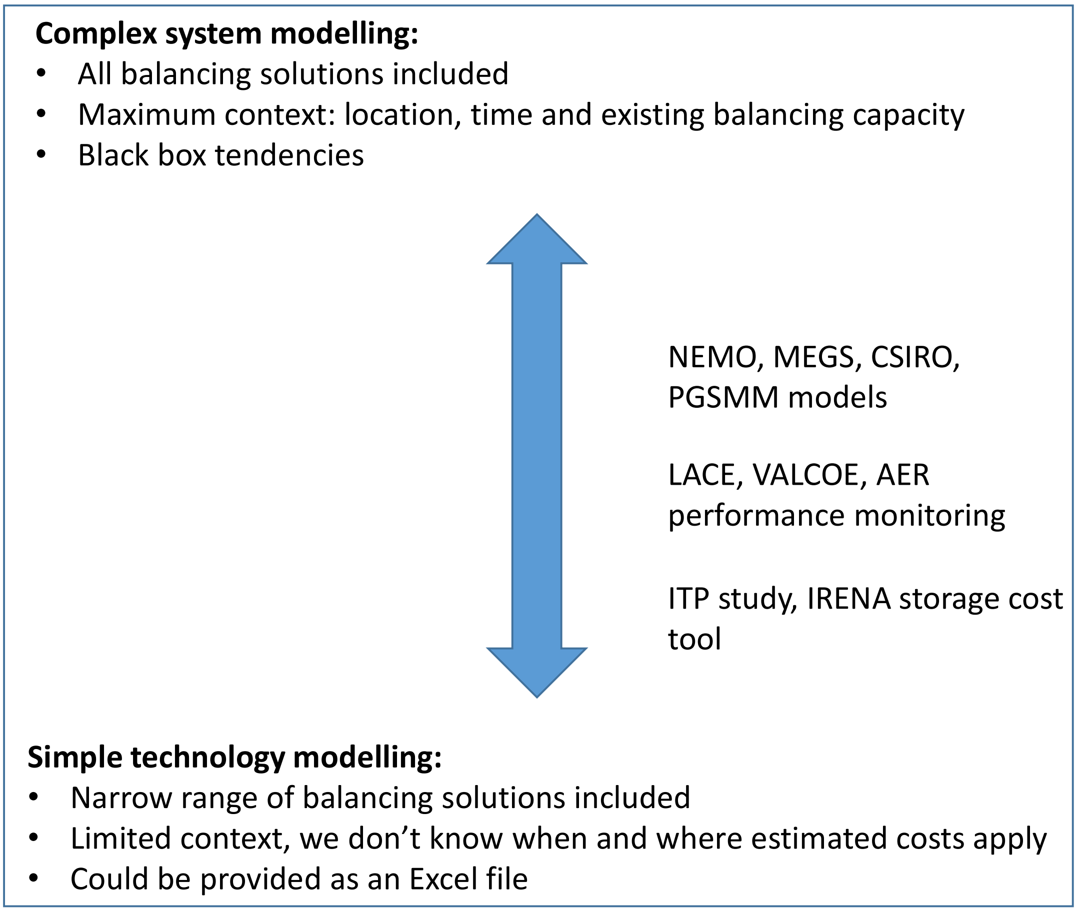

Figure 9-1: Trade-offs between the simpler and more complex approaches reviewed

The ITP, VALCOE and LACE approaches are able to produce outputs that provide an indicator of balancing costs that relates directly to a single technology. The other approaches which use system models have a preference for including combinations of technologies (e.g. wind and solar). However, they could be modified to examine increments of a single technology supported by other technologies. Note that although technology specificity is a necessary criteria, it is expected that we may also want to explore technology combinations like a combined solar and wind farm if they do not emerge naturally as balancing solutions for each other. The trade-offs between the simpler technology models and more complex system models is summarised in Figure 9-1.

Part II Options for a way forward

Proposed methods with options

A broad conclusion of the review in Part I is that we need to use electricity system models[6] to ensure that we only include balancing costs that are necessary. Without an electricity system wide modelling approach we can't be confident that balancing resources added are strictly necessary given the electricity system may already have significant existing balancing capability.

The major disadvantage of using a system modelling approach is that it includes all the complexity of electricity system models, the details of which are only understood by a narrow range of the full set of stakeholders interested in comparative technology cost measures. Furthermore, ownership and access to electricity system models can involve significant annual software licencing costs and so the repeatability and validation of the approach would be low.

However, these may be acceptable trade-offs for accuracy. The electricity system modelling pathway presents two further choices:

- Iteration versus optimisation solution process
- Open source versus proprietary model ownership.

We discuss the advantages and disadvantages of these options in the following sections.

Other opportunities

While methods which examine storage costs only fall short on grounds of breadth, we did note in Part I that IRENA and ITP publish costing tools as Excel files together with published equations. Regardless of how we progress on calculating balancing costs to extend LCOE, it may be worthwhile for the GenCost project to consider publishing storage technology costs in an Excel format that can be pasted into the relevant data sheets of the ITP and IRENA storage costing tool (or similar tools made available by other organisations as they emerge over time).

[6] Specifically we require electricity models with an hourly temporal resolution or lower which is the only way to be confident that solutions provide reliability for a full year. These tend to be dispatch models. Generation capacity expansion models are used to developed projections of technology portfolios over multiple years. They tend to simplify time including selected time slices only and therefore cannot say with confidence that demand has been met at all times. Apart from dispatch models, there are also hybrid models which blend some features from generation expansion and dispatch models.

10 Iteration versus optimisation solution

10.1 Iteration modelling approach

Electricity system dispatch models are designed to fulfil a wide range of information needs of electricity sector stakeholders and would be the main candidate tool for solving for balancing costs under an iterative approach given their high level of trust and understanding in both the modelling and broader industry stakeholder community. In this case, we specifically want to use the dispatch model to determine how much balancing costs would need to be added to variable renewables to maintain reliability. We are also interested in applying stability constraints but those are less well defined.

Dispatch models typically operate in the mode whereby they are choosing the least cost set of bids from plants available in the model to meet half hourly demand. In this case, to calculate the balancing cost for a single technology we want to create scenarios that include existing plant but only add a single generation technology of interest as demand grows or existing plant retire. We also need the model to check which combinations of balancing solutions and at what minimum capacity result in meeting the reliability standard. This could be done in two ways:

1. Run the simulation model for all relevant combinations and capacities of balancing solutions starting with none and increasing the capacity of each potential solution until reliability is achieved. For the set of balancing solutions that meet the reliability standard, convert the capacities to annualised costs and rank them to select the lowest cost combination. Under this approach, the balancing solutions would be assigned bidding strategies which only account for short-run marginal costs.
2. For each balancing solution, calculate the long run marginal cost and use this to set the minimum bidding behaviour of that technology. Allow the dispatch model to select the lowest cost balancing solution. Observe how much capacity of the balancing solution has been used in the successful bids. For the set of least cost balancing solution capacities that are selected (dispatched) and meet the reliability standard, convert the capacities to annualised costs. This approach is akin to the NEMO model discussed in Part I.

In regard to the first approach, the major drawback is the high number of iterations that might be required to be sure all potentially feasible portfolios of balancing solutions are evaluated. In practice, we generally employ a generation expansion model to narrow down the range of solutions provided to dispatch models. However, given that the time slicing of generation expansion models does not adequately represent the variability of renewables we cannot be confident that portfolio solutions from those models are complete in terms of their understanding of the need for balancing. Consequently, we cannot escape the need for a high number of iterations to explore the potential solution space.

In regard to the second approach, this would not be suitable for assessing transmission as a balancing solution because additional transmission does not enter as a bid. It would need to be assessed as a separate model run or context.

Otherwise, the second method may be preferable because it requires fewer model runs. The difficulty may arise in that the long run marginal cost is dependent on aspects of the operation of the balancing technology (e.g. for storage duration, cycles per day). If the actual operation of the technology as defined by the successfully dispatched bids is not close enough to operation that was envisaged under long run marginal cost calculations then an inconsistency arises which may invalidate the expected costs. If minor, this may only require a post-model run adjustment of the costs before adding them to the technology LCOE. If the difference is major then further iterations may be required to ensure confidence that the right balancing solution has been selected. The NEMO model demonstrates that an iterative approach of this type can work but only over a limited set of balancing solutions. It is unclear if the full set would prove too large to manage.

For either of the two iteration based approaches the full set of steps shown in Figure 10-1 must be run for each context and year of interest. The output is an LCOE with balancing costs for that context and year as envisioned in Figure 1-1.

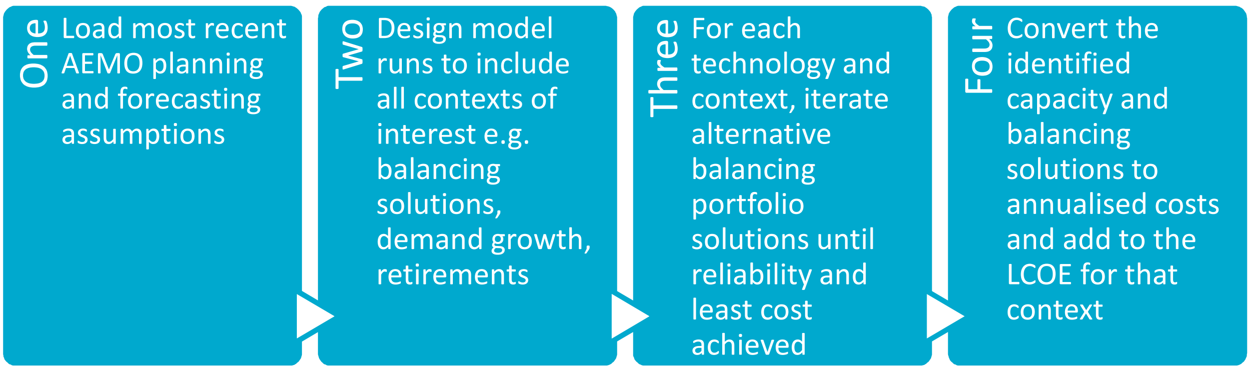

Figure 10-1: Overview of iterative solution process

The iterative approach provides a solution to optimising the amount of storage but does not solve for how to operate that capacity optimally, which includes looking forward to determine when is the appropriate period in which to charge or discharge. Dispatch models do not look forward and therefore simple rules are applied instead. Consequently, the amount of storage chosen is only optimal for that operation regime.

10.2 Optimisation modelling approach

The main limitation of dispatch models arising from our discussion in the previous section is that it may be difficult to avoid a large number of model iterations. Dispatch models are generally designed to take the generation portfolio as given (exogenous) and optimise their daily dispatch without considering what else may have been useful. We can only ask those models to consider alternatives by iterating a large number of different exogenous portfolios or by providing the model with excess capacity that only bids at long run marginal cost and seeing which technology it chooses. But as discussed, this excess capacity with long run margin cost bids might require further re-runs to ensure the dispatched operation of the technology aligns with the long run marginal cost calculation assumptions.

Ideally, we want the model to be able to optimise the capacity of all balancing technologies in an automated way within the model solution. To do this we would need to give the model both an existing exogenous portfolio plus the option to invest in additional capacity. This would represent a hybrid between a dispatch and generation capacity expansion model. However, this approach comes with the various issues that were faced by the CSIRO modelling approach reviewed. That is, to model investment we need to present the problem not as a dispatch problem but as a combined dispatch and investment problem with each time step solved simultaneously over a minimum of a whole year (or longer so that the investor is aware that the chosen investment must also recover annual costs in meeting the needs of each time step).

This need to model the whole year simultaneously means the dispatch model becomes larger by a factor of the amount of simultaneous time periods included. For a model of this size to solve in reasonable time, the representation of the dispatch problem has to be simplified. Simplifications typically include:

- Removing bids (the minimum number of technologies are selected to meet demand each time segment without an explicit stack order)
- Treating technologies as blocks rather than individual plants
- Reduced spatial representation
- Reduced representation of transmission constraints
- Limited investment horizon.

AEMOs Detailed Long Term Model (DLT)[7] as an example of a hybrid dispatch and investment model. The key simplification that DLT uses to contain model size is to reduce the representation of time to 8 hours per day over five year planning periods (resulting in only 5475 simultaneous time periods). The 8 hours a reached by representing periods with similar loads as one block but maintaining chronological time (which is important for the purposes of modelling realistic storage behaviour). DLT is formulated in PLEXOS but could be constructed in any linear programming software.

DIETER[8] is an example of an open source model[9] which also hybridises dispatch and investment modelling approaches. However there are dozens of other published model formulations to draw on. DIETER makes all of the simplifications listed above and is a one region model. DIETER is probably too simple for our purposes, given the lack of regional and transmission detail.

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[7] Details are published in the Integrated System Plan Appendices.

[8] https://www.diw.de/de/diw_01.c.508843.de/forschung_beratung/nachhaltigkeit/umwelt/verkehr/energie/modelle/dieter/dieter.html

[9] This means that equations, code and full data and software implementation are published on the internet. However, this still might require access to the software interface (although at a fraction of the cost of a full commercial dispatch model).

To adapt a model like DIETER or CSIRO's existing model state regional spatial disaggregation, including transmission interconnections would be need to be added. The model would also need additional constraints to ensure realistic plant behaviour such as must-run conditions and ramping.

On the other hand DLT would also not be sufficient. The reduction of time periods to 8 hours a day would not provide sufficient confidence that each solution is reliable for all hours of the day throughout the year. For AEMO's purposes this is not an issue because their modelling solution from DLT is passed to an hourly dispatch model and any necessary adjustments are made in that framework to meet the reliability standard.

To adapt DLT, we could consider adding back in an hourly resolution and reducing the investment horizon down from 5 to 1 year. Since 5 years is arbitrarily small anyway relative to plant amortisation periods, this should not be too detrimental. This would mean the model solves 8760 simultaneous time periods. This is 60% bigger than the current model so some further simplifications might also need to be considered to improve model size and solution time.

Whatever model we choose to adapt to find the right level of trade-off between solution time and representation of key market details, the key advantage of the optimisation approach is that we can avoid the iteration step in the solution process and go directly to the least cost amount of balancing capacity for a given context (Figure 10-2).

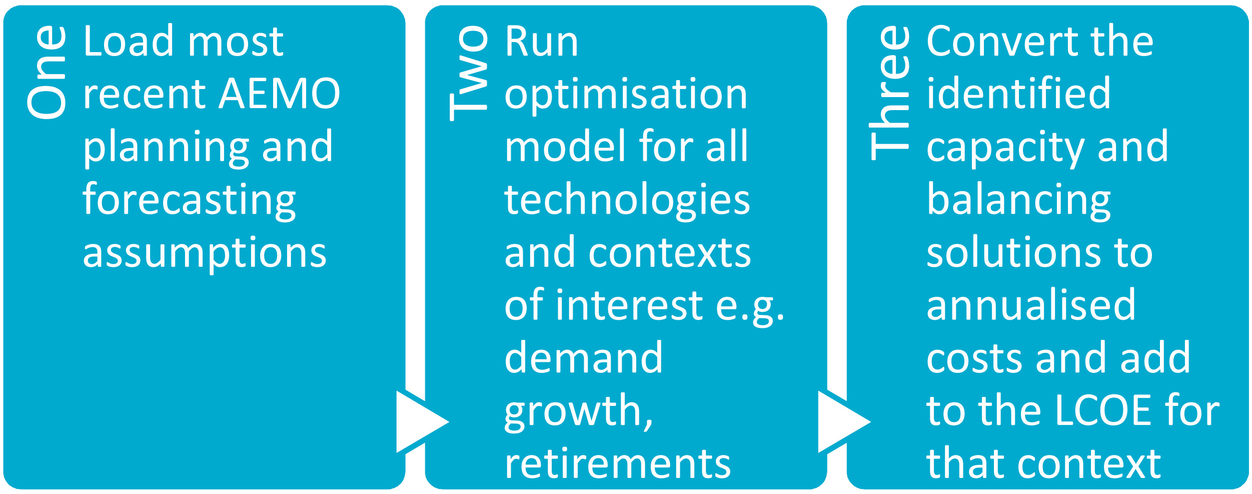

Figure 10-2: Overview of optimisation solution process

An extra advantage of the optimisation approach is that, while optimising the amount of storage it will also optimise its operation since it can include forward looking decision behaviour. That is, the optimised capacity of storage chosen is consistent with the optimised storage operating regime.

11 Open source versus proprietary model ownership

The key advantage of an open source model is that it widens the pool of potential end users increasing transparency and repeatability of the method. The increase in pool of direct model users will only be small relative to the number of stakeholders who are interested in the outputs because only a limited number of stakeholders will have the technical capacity to understand and use an electricity market model. Users who would directly use and benefit from an open source model would likely include most universities and research institutions in Australia and larger industry players. It is also possible that some overseas users would adopt the model for comparisons in their own country after modifying the model to their local conditions. All stakeholders would benefit indirectly from greater scrutiny of the method.

The key advantages of a proprietary model ownership approach is that it requires less resources, it can be hosted within existing specialised commercial software packages which are of high quality and there can be a single source of the data outputs. If the model is open source there is the potential for variants of the model to provide conflicting data to stakeholders. The model might also be used for purposes it was not well designed for.

Whether we take the iterative or optimisation approaches discussed in the previous section, there will be software licence costs to any users. However, the open source approach could target lower cost software to host the model and universities and other academic institutions often receive access to such software at a discounted rate.

CONTACT US

t 1300 363 400
+61 3 9545 2176
e csiroenquiries@csiro.au
w www.csiro.au

FOR FURTHER INFORMATION

ENERGY
Paul Graham
t +61 2 4960 6061
e paul.graham@csiro.au
w www.csiro.au/energy