Modelling the impacts of constrained network access

Public report

Public Utilities Office

1 October 2018

Building a better working world

Notice

Ernst & Young ("we" or "EY") has been engaged by the Public Utilities Office ("you", "PUO" or the "Client") to provide electricity market modelling services to assist the PUO in investigating the relative financial impacts of implementing a constrained network access regime on existing and new generators in the Wholesale Electricity Market (the "Services"), in accordance with our Letter of Appointment dated 21 November 2017 and the Panel Contract.

The enclosed report (the "Report") sets out the modelling methodologies, key data inputs and assumptions and the outcomes of the modelling. The methodology described, together with the scenarios and assumptions used, have been agreed with the PUO, as a result of a public consultation process undertaken in March 2018. This Report is standalone and contains the assumptions and modelling methodology used as well as describing the outcomes. It also describes the changes to the assumptions compared to the original published modelling methodology and assumptions report in an Appendix.

The Report should be read in its entirety including the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. The report has been constructed based on information current as of 18 September 2018 (being the date of completion of this Report), and which has been provided by the Client, other stakeholders or is available publicly. Since this date, material events may have occurred that are not reflected in the Report. Therefore, our Report does not take account of events or circumstances arising after the date of completion of this Report and we have no responsibility to update the Report for such events or circumstances.

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Modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved, if any. Further, the outcomes are contingent on the collection of assumptions as agreed with the PUO and no consideration of other market events, announcements or other changing circumstances are reflected in this Report. Neither EY nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided to EY or other information sources used.

Executive Summary

EY has been engaged by the Department of Treasury's Public Utilities Office (PUO) to provide electricity market modelling services to assist the PUO in investigating the impacts of implementing a constrained network access regime in the Wholesale Electricity Market (WEM) in Western Australia (the Project).

The objective of the modelling is to quantify the relative financial impact to generators and whole of system outcomes as a result of this transition being complete in 2022. The modelling was conducted for the period from 1 July 2022 to 1 July 2032 (the Study Period).

A number of scenarios were examined to account for uncertainties in future electricity demand and supply availability. This report presents two scenarios selected by the PUO which explore changes in supply and demand balance outlook focussing on the relative impact on generator dispatch due to alternative network access frameworks. The scenarios were developed by the PUO, in consultation with EY and based on feedback received through a public consultation process held by the PUO in March 2018. Table 1 provides an overview of the two scenarios that are presented in this report. Apart from demand forecasts, the scenarios use a consistent set of input assumptions, including individual generator technical parameters and costs. Demand assumptions are based on the Australian Energy Market Operator's WEM Electricity Statement of Opportunities forecasts. These are described in detail in Appendix B of this Report.

Table 1: Overview of the scenarios

Assumption	Base Scenario	High Scenario
Demand forecast	Expected	High
Network access cases modelled	Partially Constrained Fully Constrained Unconstrained (Firm)	Partially Constrained Fully Constrained

In each scenario two cases were modelled: Partially Constrained Access and Fully Constrained Access. In addition, a third case; Unconstrained Access, was modelled in the Base Scenario. These three cases can be described as follows:

- **Partially Constrained Access** represents the status quo in the WEM. In this case existing generators maintain their firm access entitlements but new entrant generators are subject to generation curtailment in response to network congestion.

- **Fully Constrained Access** represents the full implementation of the constrained network access reform. In this case both existing and new entrant generators are subject to generation curtailment in response to network congestion.

- **Unconstrained Access** represents a complete return to the firm access regime in the WEM. This involves all existing and new entrant generators having Unconstrained Access entitlements. For the purposes of this exercise, sufficient transmission network capacity is assumed to be built and funded by the Western Australian Government to ensure all generators have firm, unconstrained access to the network.

In each scenario and case, EY conducted time-sequential half-hourly electricity market modelling of the WEM over the Study Period to forecast new entrant generator capacity on an economic basis. The modelling uses EY's electricity market dispatch software, 2-4-C® with offers (bids) for each individual generating unit (Synergy units are also modelled with offers on an individual basis) that form a merit order allowing dispatch and the balancing market price to be computed for each half hour. The generating unit offers were developed from an extensive benchmarking exercise of the

2016-17 historical financial year. The benchmarking methodology and outcomes are described in Appendix A of this Report.

The network constraint equations used in each case were developed by Western Power and the PUO. These include a set of candidate new entrant technologies and locations, based on the public consultation process held by the PUO in March 2018.

The capacity market was modelled separately, using a formula from the WEM Market Rules to forecast the reserve capacity price based on the difference between the total amount of allocated capacity credits and the reserve capacity requirement (RCR) in each modelled year. The capacity credits allocated to each generator was determined by the PUO using the latest version of its capacity credit allocation tool. This tool uses methods previously discussed during the consultation process in this Project. The capacity credit allocations were calculated for each scenario and case.

The differences between the modelling outcomes of the Fully Constrained Access and Partially Constrained Access cases is used to forecast the quantitative impacts of the constrained network access reform relative to the status quo. The differences between the modelling outcomes of the Unconstrained Access and Partially Constrained Access cases is used to forecast the quantitative impacts of a return to a firm access regime relative to the status quo.

Network constraint outcomes

During the course of the iterative modelling, selected candidate new entrant generator locations[1] were trialled for potential new entrant capacity. In many locations it was found that the network constraint equations bound frequently with a relatively small amount of additional new entrant capacity. In some areas, such as Albany, North Country and East Country, the modelling indicated a limit of around 40 MW to 100 MW of additional wind or solar PV capacity that could be economically viable due to the level of network constraints binding, where the limit might be a little higher in the Fully Constrained Access Case depending on the capacity mix and demand in the rest of the market.

In addition to the network transmission limitations, Western Power advised the PUO and EY that the fault level at the Kwinana 132 kV bus exceeds its capability if more than 100 MW additional capacity[2] is connected at that location. An alternative Kwinana connection point is at 330 kV, where Western Power advised there is a 350 MW limit for similar reasons. New capacity at the 330 kV connection point is not limited by thermal transmission capacity from the network constraint equations modelled.

As a result of these limits the final capacity mix forecast in each scenario and case (except the Unconstrained Access Case) was limited to the following locations and technologies:

- **Kwinana, Kemerton or Eastern Goldfields for OCGTs and CCGTs.** Two locations are considered at Kwinana, with the 132 kV location having a 100 MW limit and the 330 kV location having a 350 MW limit. In the High Scenario more capacity is required to meet the higher level of peak demand than is the case under the Base Scenario. In the High Scenario case, the PUO instructed EY to assume that Western Power builds the necessary equipment to allow sufficient capacity to connect at Kwinana.

- **Albany, Bunbury, East Country, Eastern Goldfields and North Country for wind and solar PV**, with the modelling outcomes driving capacity limits in each case as noted above.

For the above locations and technologies, EY forecasts that the network constraint equations will bind very infrequently for any scenario and case. In contrast, the PUO's capacity credit calculations are based on the peak demand period only and therefore the network constraint equations bind more frequently and have a material impact on capacity credit allocations in some cases. In

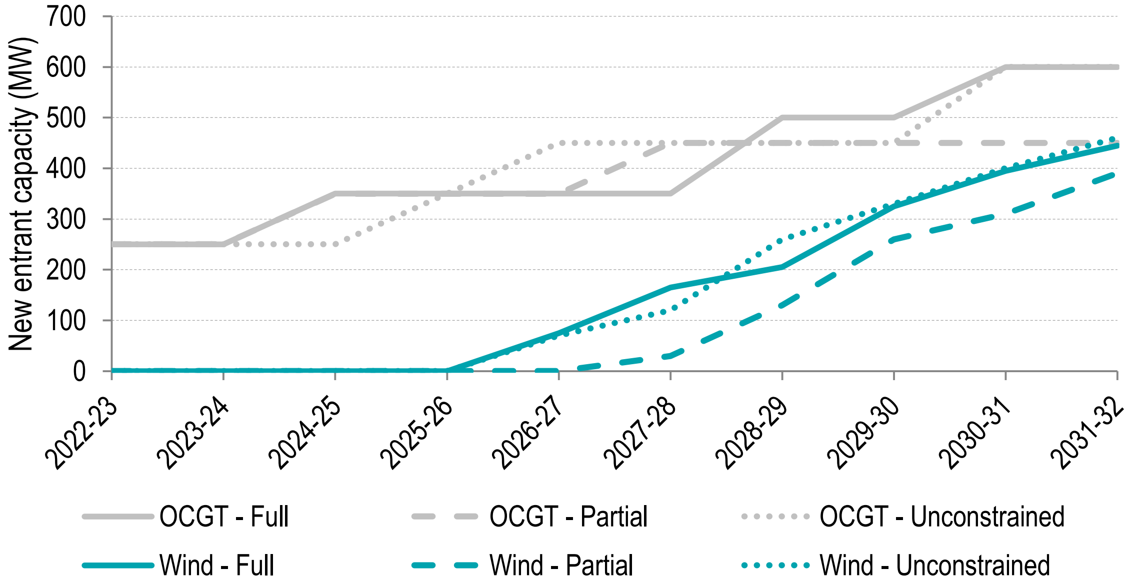
[1] The candidate new entrant locations were devised by the PUO, in consultation with EY, and were agreed on following the public consultation process in March 2018. The locations are presented in Section B.12.
[2] This assumes that new generation installed will have some fault level mitigation as part of its connection

particular, the capacity credit allocations in the Partially Constrained Access Cases tend to be reduced for new entrants in Kemerton, Eastern Goldfields, East Country and North Country. As a result of this and the Kwinana limits discussed above, less capacity is found to be commercially viable in the Partially Constrained Access Cases compared to the Fully Constrained Access Cases.

Capacity mix outcomes

Figure 1 presents the forecast new entrant large-scale[3] capacity mix over the Study Period in each case of the Base Scenario.

Figure 1: Forecast large-scale new entrant capacity by type in the WEM – Base Scenario, all cases



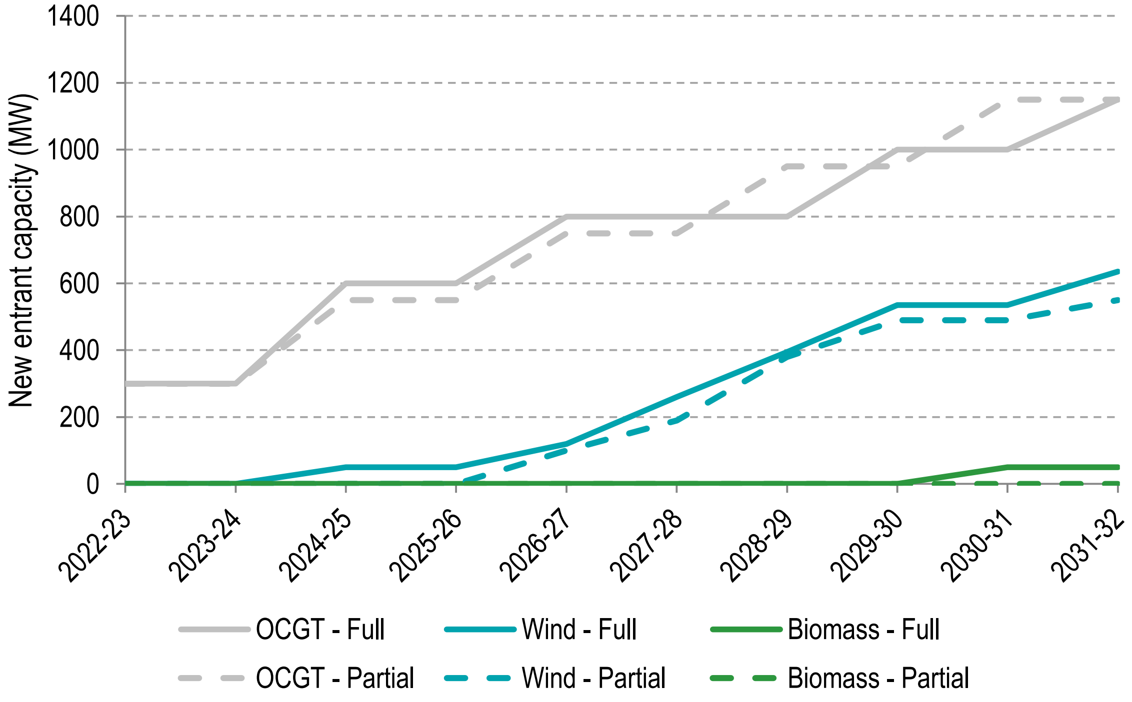
The only generation investments forecast, apart from the assumed uptake of rooftop PV, are additional wind and OCGT capacity. Based on the cost assumptions used for existing generators, no commercially-driven retirements are forecast in the Base Scenario in the Study Period.

Overall, less new entrant capacity was found to be commercially viable in the Partially Constrained Access Case compared to the other two cases. This is due to a combination of the Kwinana capacity limit and reduced allocation of capacity credits being forecast by the PUO for potential new entrant capacity in locations other than Kwinana.

[3] Large-scale capacity mix omits rooftop PV uptake as this was an assumption rather than an outcome. The assumed new entrant rooftop PV is approximately 1,000 MW over the Study Period, as per the AEMO 2018 WEM ESOO Expected scenario used. This new entrant large-scale capacity also does not include the assumed wind and solar generators commissioned by 2022.

Figure 2 presents the forecast new entrant large-scale capacity mix over the Study Period in both cases for the High Scenario.

Figure 2: Forecast large-scale new entrant capacity by type in the WEM – High Scenario, both cases

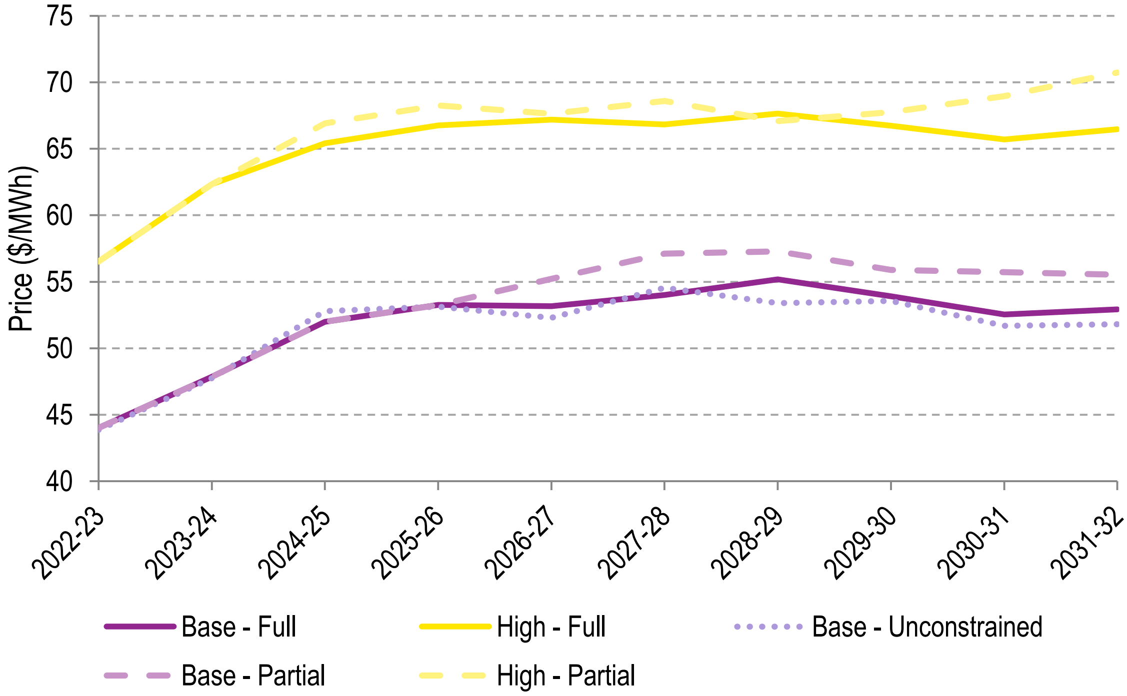


Due to the higher demand, the amount of new entrant capacity forecast in the High Scenario is higher than the Base Scenario for both OCGT and wind capacity. In addition, 50 MW of biomass capacity is forecast to be installed in the Fully Constrained Access Case. This biomass capacity is not forecast to enter in the Partially Constrained Access Case as the formulation of the network constraint equations in that case prevent the potential biomass generator located in Muja from receiving capacity credits. For the same reason, wind capacity is found to be viable in earlier years in the Fully Constrained Access Case, and by 2031-32 there is 85 MW of additional wind capacity forecast in that case.

Balancing market price outcomes

Figure 3 shows the forecast annual average balancing market prices for each scenario and case.

Figure 3: Forecast annual average balancing market prices in each scenario and case* (June 2018 dollars)



* Note the y-axis is truncated for clarity

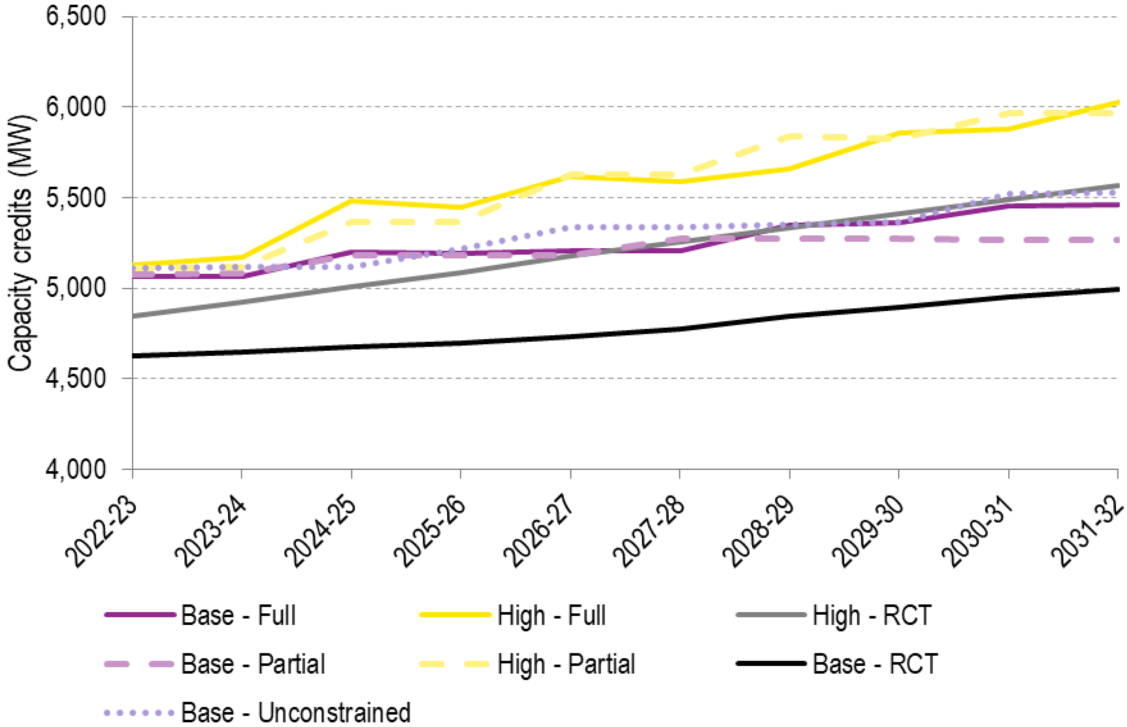
The forecast balancing market prices have generally increasing trends across the Study Period. The forecast increase in the first three years of the Study Period is primarily due to the assumed increase in the gas price.

In each scenario, the annual average balancing market prices are forecast to be lower in the Fully Constrained Access Case compared with the Partially Constrained Access Case. This is primarily driven by the merit order effect with the additional generator capacity installed in the Fully Constrained Case.

Capacity market outcomes

After installing the commercially-driven new entrant capacity in each scenario and calculating the capacity credits, the total amount of capacity credits allocated is above the reserve capacity requirement (RCR) in all cases and years. Figure 4 shows the forecast total capacity credits in the Base and High Scenario compared with the reserve capacity target in those scenarios.

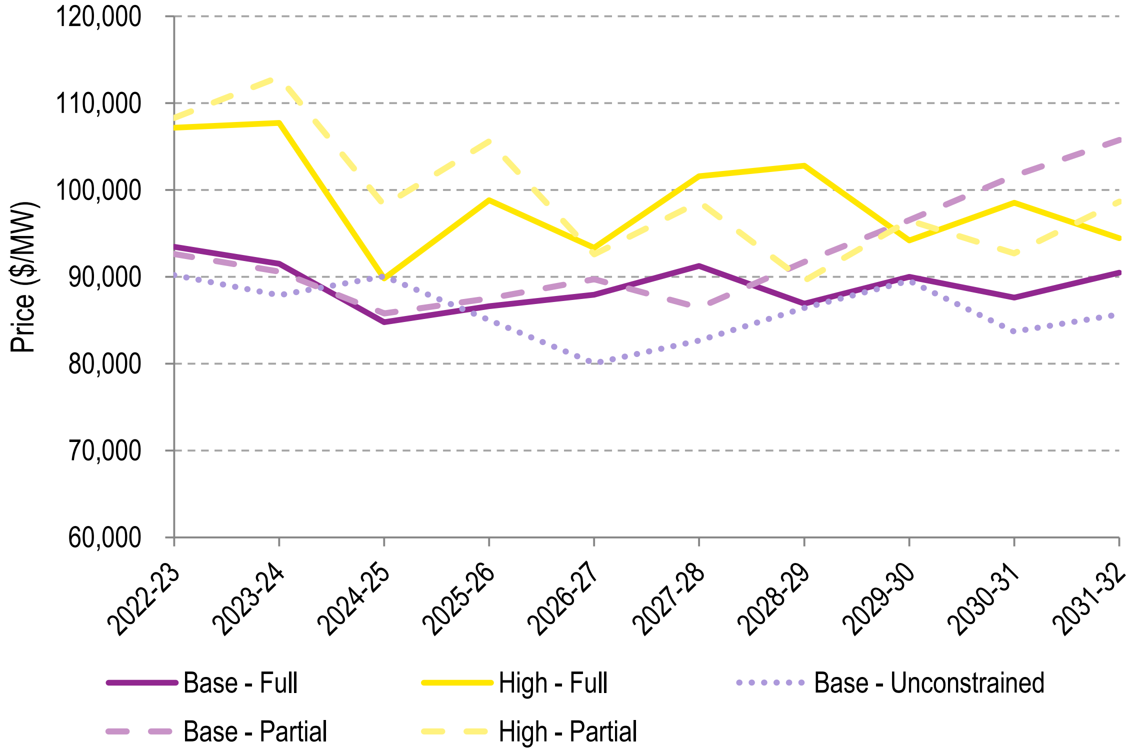
Figure 4: Total capacity credits versus the reserve capacity target in the Base and High Scenario



In the High Scenario, a surplus of 200-300 MW above the RCR is initially forecast for 2022-23 and this grows to 400-500 MW by 2031-32, in both cases. Provided there is potential new entrant OCGT capacity with full capacity credit allocation, a new entrant OCGT typically is found to be economically viable with a surplus of 400-600 MW of capacity credits in all scenarios. In the Partially Constrained Access Cases, this condition is not true with reduced capacity credits leading to less OCGT capacity being forecast to be installed. The consistent capacity credit surplus in the modelling results in no unserved energy being forecast in any scenario or case.

Figure 5 shows the resulting forecast capacity market prices in each scenario and case.

Figure 5: Forecast capacity market prices for each scenario and case*[4]



* Note the y-axis is truncated for clarity

The capacity market prices are forecast to be lower than the latest reserve capacity market price of $126,683/MW set by AEMO for 2019-20.[5] The primary driver of the forecast capacity market prices is the cost assumptions used for OCGTs in the modelling (as agreed by the PUO, in consultation with EY, following the public consultation in March 2018). If the assumed costs were higher, a new entrant OCGT would require a higher revenue to be profitable, leading to less OCGT capacity and a higher capacity market price being forecast.

[4] The capacity market price is forecast using the formula in the WEM Market Rules and is based on a Benchmark Reserve Capacity Price (BCRP) of $139,154/MW. The BCRP is obtained from https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Benchmark-Reserve-Capacity-Price and has been reduced due to CPI conversion. If a higher BRCP were used, additional new entrant OCGT capacity would be forecast to be installed and the forecast capacity market price would be similar to the outcomes presented in this Report.

[5] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Benchmark-Reserve-Capacity-Price

Overall market cost outcomes

The overall market cost impacts of Fully Constrained Access compared to the other cases was estimated from the market modelling outcomes focussing on two key cost impacts:

- **Total market payments:** this is the total amount paid to generators from the balancing market, LGC market and capacity market, and
- **Network investment:** this is the cost of investment in any transmission network augmentations required for the case modelled. Western Power provided the network cost estimates after determining the required augmentations in each case. Network augmentations were only determined to be required in the Unconstrained Access Case conducted in the Base Scenario.

The Partially Constrained Access cases result in the highest total market payments and net system costs compared to the Fully Constrained Access cases in each scenario. Table 2 presents the outcomes for the Fully Constrained Access Case and, in the Base Scenario the Unconstrained Access Case, relative to the Partially Constrained Access Case in each scenario. These final numbers are different to the draft numbers presented in the PUO's constrained access report[6] dated 9 August 2018 for the Base Scenario due to refinements made to some aspects of the modelling, including incorporation of the aforementioned Kwinana capacity limit.

Table 2: Forecast overall market cost impacts by case, compared to the Partially Constrained Access Case

Scenario and case	Total market payments difference (10-year NPV)	Total market payments difference (60-year NPV)	Network costs difference	Net impact
Base - Unconstrained Access	-$0.3b	-$1.0b	+$0.7b	-$0.3b
Base - Fully Constrained	-$0.2b	-$0.8b	$0.0b	-$0.8b
High - Fully Constrained	-$0.15b	-$0.45b	$0.0b[7]	-$0.45b

The total market payments is presented as a net present value over two time periods: the Study Period of 10 years and a 60-year period. The 60-year period allows a direct comparison between the total market payments and network costs between the Partially Constrained, Fully Constrained, and Unconstrained Access Cases as network investments are expected to have an economic life of 50 years. The 60-year NPV for the total market payments represents the net present value of the impact on the payments to 2080-81 with the chosen discount rate. This is based on an extrapolation of the ten years modelled by repeating the average of the final three years for every year post 2031-32. All the numbers are presented as a net present value and have been discounted[8] back to June 2018, as well as being presented in June 2018 dollars.

As indicated in Table 2, lower total market payments are forecast in the Fully Constrained Access Case compared with the Partially Constrained Access Case. A return to Unconstrained Access is also forecast to have lower market payments than the Partially Constrained Access Case, but higher than the Fully Constrained Access Case.

[6] https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Consultation-Paper-Two-Improving-access-to-the-Western-Power-Network.pdf

[7] The cost for the network upgrade required in the High Scenario to allow more capacity at Kwinana is the same in both the Fully Constrained Access and Partially Constrained Access Cases, so the difference in network costs is $0b.

[8] A pre-tax real discount rate of 7.5% was used, based on the public consultation process in March 2018.

Modelling limitations

Whilst each scenario modelled captures potential future evolutions of the WEM over the Study Period, there are other scenarios that could transpire and lead to significantly different outcomes.

Aside from uncertainty in the input assumptions, some other key limitations in the modelling methodology are:

- Network upgrades or augmentations were only considered where they were deemed necessary from a power system reliability point of view, as is the case in the High Scenario. If a network upgrade were to be built that would alleviate network constraints in the Mandurah area or the fault level limit in Kwinana, the outcomes in the scenarios may be different. The Unconstrained Access Case also accounts for network augmentations, where these are required to ensure no generator can be constrained off in system normal conditions.
- The PUO's capacity calculator can reduce capacity credits allocated to generators as a result of generation from other generators being constrained on. This has been identified in the case of generators at the Kwinana 132 kV location being constrained on to meet peak demand and resulting in generators in North Country receiving reduced capacity credits in the Partially Constrained Access cases. An alternative outcome to this is being considered by the PUO in such cases, but this was not factored into the outcomes presented in this Report.
- The constraint equation formulation is based on system normal N-1 conditions, which are designed to ensure power system security in the event of any single contingency. However, in the actual market, AEMO may invoke additional or alternative network constraint equations during periods of transmission network outages or other events. This could lead to alternative dispatch and balancing market price outcomes during these periods. The modelling does not consider such events.
- Ancillary services requirements were not explicitly modelled, including the load following ancillary services (LFAS) market. As such the impact of constrained access on ancillary services was not considered.
- The modelled dispatch is based on a least-cost dispatch algorithm with the Synergy units disaggregated, with generator offers that attempt to emulate the present dispatch behaviour of each individual generating unit. The offer (bid) profiles were developed in a benchmarking exercise on the 2016-17 financial year. This approach effectively maintains the status quo in terms of generators providing ancillary services such as load following and spinning reserve, and does not allow for potential changes to the requirements for those services throughout the Study Period. However, it is considered that capturing the impact of dynamic participation by generators in ancillary services would not have a material impact on the outcomes presented in this Report.
- All generators were assigned a fixed assumed marginal loss factor (MLF) across the Study Period, with the exception of new entrant wind and solar generators in East Country and Eastern Goldfields, which were assigned a formula-driven MLF that depends on the amount of wind and solar PV capacity installed in each of those areas.[9] The MLF for all new entrants is based on an MLF from an existing generator electrically nearby. If the MLFs were modelled explicitly they could potentially be forecast to change from the assumed MLFs and from year to year across the Study Period. This could result in different capacity mix forecasts to those presented.
- A single static number was assumed for each generator's heat rate, so the modelling does not take into account a generator's state of operation on its heat rate and associated short-run marginal cost curve. This is not considered to have had a material impact on the outcomes presented in this Report.

[9] This is due to these two regions being considered to have MLFs that are much more impacted by the total capacity installed in those regions than in other regions in the WEM. The formula derived for each is described in Section B.12.

Conclusion

In each scenario modelled, the Fully Constrained Access Case results in the lowest overall costs of electricity supply for consumers, compared with the Partially Constrained Access Case. This is primarily a consequence of forecast lower balancing market prices and forecast lower capacity market prices on average across the Study Period due to more new entrant capacity being viable in the Fully Constrained Case.

The Fully Constrained Access Case is also forecast to have a lower cost than Unconstrained Access Case in the Base Scenario. This is primarily due to the forecast deferral of future network investment in the Fully Constrained Access Case compared with the Unconstrained Access Case.

The wholesale market modelling found very little binding of network constraints across the Study Period in any case and scenario modelled. The network constraints were found to bind more frequently during peak demand periods, impacting how capacity credits are allocated to existing and new entrant generators in both the Fully Constrained and the Partially Constrained Access Cases. This impact on capacity credits affects the commercial viability of new entrant generation capacity and is the primary driver of differences in the timing, location and quantity of installed capacity mix between the cases modelled that, in turn, drives differences in wholesale market prices and total market payments.

The net revenues for existing generators is forecast to be lower in the Fully Constrained Access Case relative to the Partially Constrained Access Case in all scenarios. This is primarily a result of reduced capacity credits and being displaced in the merit order due to additional, lower cost generation investment, rather than being constrained off as a result of network constraints.

Based on the scenarios modelled, it can be concluded that in a Partially Constrained Access future it will be more difficult to meet the objectives of minimising costs and maintaining reliability in the WEM compared to Fully Constrained Access. This difficulty is more emphasised, the more new entrant capacity is needed or incentivised because the Partially Constrained Access environment presents fewer commercially viable opportunities for new entrant capacity.

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1. Introduction

EY has been engaged by the Department of Treasury's Public Utilities Office (PUO) to provide electricity market modelling services to assist the PUO in estimating the impacts of implementing a constrained network access regime in the Wholesale Electricity Market (WEM) in Western Australia (the Project).

The objective of the modelling is to quantify the relative financial impact on generators and whole of system outcomes as a result of this transition, for the period from 1 July 2022 to 1 July 2032 (the Study Period).

The objective of this report is to describe the modelling methodologies, the data and input assumptions used and the outcomes of the electricity market modelling undertaken for the Project.

This report forms a single complementary part in a broader set of papers related to implementing a constrained network access regime. These papers can be found on the Department of Treasury's website: https://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/Constrained-Network-Access-Reform/.

In preparing the modelling assumptions, we have used information that has been made publicly available through industry consultations (including the consultation conducted as part of this Project in March 2018) and various industry publications to the extent practicable. The scenario assumptions have been selected by PUO based on consultation between EY and the PUO. We note that there is a significant range of alternative scenario assumptions that, in isolation or in aggregate, could transpire to produce outcomes that will differ to those that will be modelled.

All prices in this Report refer to real June 2018 dollars unless otherwise labelled. All annual values refer to the fiscal year (1 July – 30 June) unless otherwise labelled.

1.1 Background

The State Government is working towards improving access to Western Power's network by implementing a fully constrained network access regime.

As part of this, the PUO is analysing the impacts of transitioning from the present network access regime in the WEM towards a fully constrained network access regime. These impacts are to be informed by electricity market modelling that quantifies potential changes to generator dispatch outcomes, revenue projections and generation supply adequacy.

The implementation of constrained access in the WEM will alter the way that generators are currently dispatched. All generators participating in the Australian Energy Market Operator's (AEMO's) central dispatch process are dispatched according to an economic least-cost algorithm, taking into account generator offers and transmission loss factors, whilst adhering to power system security limitations defined within the dispatch engine.

Western Power is currently developing and implementing the Generator Interim Access (GIA) tool, which will facilitate the connection of new entrant generators to the Western Power Network (WPN) on a constrained basis whilst preserving the network access rights of incumbent generators. These parties[10] have stated that the GIA tool is interim in nature and will be decommissioned following the implementation of a constrained network access regime, enabled by a redesign of the WEM dispatch engine.

[10] AEMO WA Generator Forum (5 April 2017)

1.2 Implementation cases

To quantify the relative financial impact on generators and whole of system outcomes as a result of constrained access, the PUO instructed EY to compare outcomes in a Fully Constrained Access environment against the counterfactual of a Partially Constrained Access environment. In addition, an Unconstrained Access Case was modelled in the Base Scenario. Table 3 provides a summary of the three cases.

Table 3: The three cases modelled by EY

Case	Description
Fully Constrained Case	From 1 July 2022,[11] existing generators and any new entrant generators connecting to the Western Power Network (WPN) are subject to generation curtailment in response to network congestion.[12] Network constraint equations[13] are defined to set power transfer limits for use in the dispatch engine. Consideration of which generators(s) are constrained will be based on achieving a least cost objective.
Partially Constrained Case (counterfactual)	From 1 July 2022, the existing GIA connected generators and any new entrant generators connecting to the WPN are subject to generation curtailment in response to network congestion. Existing generators will retain their existing access entitlements.[14] Network constraint equations are defined to set power transfer limits for use in the dispatch engine. Consideration of which generators(s) are constrained will be based on achieving a least cost objective.
Unconstrained Access Case	From 1 July 2022, all existing and new generators receive firm access rights, with similar arrangements to the existing access entitlements.[14] It is assumed that sufficient network capacity is built (and funded by the Western Australian Government) to ensure all generators can have full access to the network at any point in time, provided all network elements are in service.[14] The system is dispatched without any network constraint equations, and is based solely on merit order.

In the Fully Constrained case, the output of all generating units can be constrained in a least cost manner by market dispatch processes in order to maintain power system security. All generators may be constrained on or off in this case, to an amount anywhere between zero and a defined limit.

The Partially Constrained Case represents the generator connection access environment in 2022 should fully constrained access reforms not proceed. This case represents a continuation of the current status-quo treatment of generators but with the implementation of a redesigned WEM dispatch engine. In this case, generators with an existing access entitlement retain their current

[11] Though 1 October 2022 represents the start date for constrained access, modelling will be performed for the Study Period beginning 1 July 2022. No material impacts are expected in the modelling outcomes.

[12] Not all generators will be required to participate in the central dispatch process. This will be dependent on registration class requirements.

[13] Network constraint equations define the power system transfer limits and are formulated according to AEMO's constraint equations formulation guidelines. They are derived by Western Power. These network constraint equation sets for the Fully Constrained Case and the Partially Constrained Case define the same network limitations, that is, there is no change in the power transfer limit across both cases. Differences in the formulation are based on which generator may be subject to curtailment.

[14] We have been advised that existing generators access entitlements only apply under operational conditions where all relevant network elements are in service. Generators may still be subject to loss of generation associated with an existing generation runback scheme or due to manual intervention by AEMO to manage power system security. These provisions are provided for in access contracts. These aspects will not be explicitly modelled.

level of access with their dispatch effectively prioritised over generators that have been connected on a constrained basis. All future generator connections will be on a constrained basis.

The Unconstrained Access Case represents a return to an unconstrained access environment for all generators. This would involve moving the GIA generators to unconstrained access and for all new generators being able to connect with firm access rights without any costs associated with augmenting the shared transmission network. For the purpose of this exercise, the costs of the required network augmentations to achieve unconstrained access for all generators is assumed to be borne by the State.

1.3 Purpose of the modelling

The modelling conducted has the objective of forecasting the future overall market benefits and costs from the Partially Constrained, Fully Constrained and Unconstrained Access cases in the WEM. The modelling is intended to quantify potential changes to generator dispatch outcomes and to identify trends in revenue projections.

The modelling undertaken here is not intended to be, and should not be taken as a market projection or an assessment of the commercial viability of generation assets in the WEM. We recognise that there may be existing contractual arrangements that EY does not have access to and therefore cannot model due to information constraints. EY's modelling task is primarily to quantify the overall relative impact on generators and whole of system outcomes of Fully Constrained Access compared to the counterfactual of Partially Constrained Access and a return to firm access.

The PUO has requested EY to consider the relative financial implications to individual generators as a result of network limitations constraining generators on or off in central dispatch. Due to confidentiality, these are being discussed with generators one on one. However, some outcomes aggregated by region are presented in Section 7.7. Aspects of generator revenues considered in the modelling are:

- ► Wholesale electricity market revenue
- ► Revenue from Large-scale renewable energy Generation Certificates (LGCs)
- ► Capacity credit allocations and reserve capacity price outcomes.

The introduction of constrained access may result in other types of financial losses that are not captured in the market modelling conducted by EY. The PUO advises that these other types of losses will be the subject of further consultation with individual generators over the coming months.

1.4 Out of scope

A number of explicit items have been excluded from this Project. This list includes (but is not limited to):

- ► An assessment of the forecast capacity mix that may be derived as a result of Western Power augmenting parts of the transmission network that are constrained (except in the Unconstrained Access Case). EY has not been requested to assess net market benefits for any specific network augmentation option. The modelling assumes committed and very advanced network augmentation projects (discussed in Section 6.1.6) when formulating constraint equations only to provide upper bounds for network congestion. This also recognises that generation connections typically lead network augmentation due to project execution timeframes.

- ► An assessment of network curtailment outcomes for network conditions other than system normal. The constraint equations are formulated on the basis of the transmission network without any planned or unplanned outages on transmission elements. EY has been advised that provisions are contained in existing connection contracts such that generation curtailment can occur in response to outages that occur during conditions other than system normal.

Additionally, long term transmission planning and subsequent network investment is based on N-1 planning philosophies under system normal conditions.

- Modelling elements of a reserve capacity auction and/or other proposed options associated with reforms to the Reserve Capacity Mechanism (RCM), such as demand curves for capacity pricing, auction parameters or others. Further consultation will be conducted by the PUO on reforms to the design of the RCM. Notwithstanding the above, modelling of capacity credit allocations will be consistent with the methodology described in the consultation paper "Allocation of capacity credits in a constrained network".[15]

- Future changes in transmission marginal loss factors (MLF) as a result of the generation development in the market. EY has been provided MLFs from the PUO based on the Regional Reference Node (RRN) located at Southern Terminal, reflecting the benefits of locating the RRN at a major load centre rather than a generation centre.

- Along with a constrained access regime, another reform under consideration for the WEM is to reduce the dispatch cycle from 30 minutes to five minutes.[16] Modelling five-minute dispatch is beyond the scope of this Project. However, it involves preparing five-minute input profiles for demand wind and solar generation and solving the same dispatch algorithm as for 30-minute modelling, just over a five-minute time step. In the modelling outcomes, generator ramp rate limitations are more likely to bind over a five-minute time step rather than over 30-minutes, which can change dispatch outcomes. While dispatch and price outcomes with five-minute dispatch may differ, EY considers it unlikely to have a significant impact on the overall impact of constrained access on generators.

- All other items not explicitly discussed in this Report.

1.5 Report structure

The following summarises the structure of the remainder of this Report:

- Section 2 presents a high level introduction to elements of wholesale electricity market modelling

- Section 3 provides an overview of the modelling process undertaken by EY and the PUO

- Section 4 summarises the electricity market development scenarios and provides an overview of the assumptions

- Section 5 describes the methodology for forecasting the generator capacity mix

- Section 6 describes the market modelling methodology in detail

- Section 7 describes the forward-looking modelling outcomes

- Appendix A presents the outcomes of the benchmark modelling

- Appendix B presents the input assumptions in detail

- Appendix C provides a description of weightings used in market modelling simulations

- Appendix D provides a list of acronyms and glossary of terms.

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[15] Allocation of capacity credits in a constrained network – Consultation Paper

[16] Improving access to Western Power's network – Consultation Paper

2. Overview of market modelling

2.1 Wholesale electricity market modelling

Wholesale electricity market modelling in this Project is conducted using EY's in-house market dispatch modelling software 2-4-C®. 2-4-C® seeks to replicate the functions of the real-time dispatch engines used in wholesale electricity markets with dispatch decisions based on market rules, considering generator offer patterns and availabilities to meet regional demand.

In this Project, 2-4-C® has been used to model generation dispatch in the WEM at a trading interval (30 minute) granularity in a time-sequential manner. This captures the intermittency of renewable projects as well as the underlying changes to demand, operation and transmission capabilities. The model takes into account generator outages, half-hourly renewable energy generation availability as well as transmission network limitations. The dispatch of generators is based on a least-cost objective to minimise the overall cost of supplying demand.

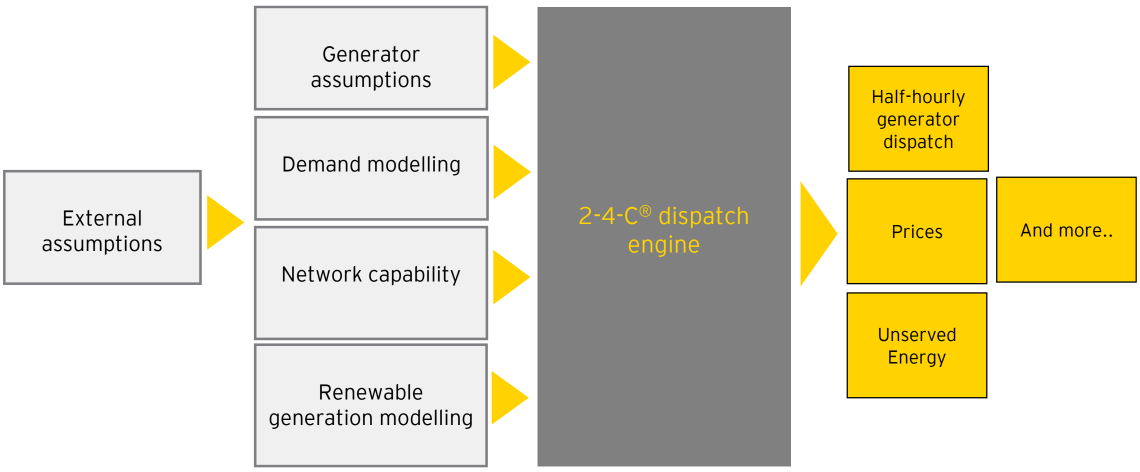
At a high level, for each 30-minute trading interval in the defined study period, 2-4-C® simulates the dispatch of generators to meet a forecast load demand target subject to defined constraints. Constraints in the model can represent a range of physical limits associated with network power transfer limits, generator plant capability, contractual supply limits and more.

The outputs that are reported from the model include the output of each generator (in MW or GWh), the market clearing price (in $/MWh), presence of unserved energy (USE) and generator availability amongst many other metrics. These outputs are analysed by EY to provide the modelling outcomes required for this Project, which are listed in Section 3.2.

2.2 Data and input assumptions

In practice, market modelling of this nature is highly complex and involves establishing a large set of data and input assumptions that are often inter-related. Assumptions are grouped into five general categories which are described at a high level below. Some of the input assumptions are processed in models external[17] to the 2-4-C® dispatch software to determine the quantities to be used. Figure 6 provides a high level overview in diagram form.

Figure 6: Simplified high level overview of 2-4-C®



[17] An example of an external assumption not used directly in dispatch modelling for the WEM is the Reserve Capacity Requirement. This assumption and its application in the modelling will impact generator capacity development by setting the capacity credit requirement and the surplus used in calculating the Reserve Capacity Price.

- Generator assumptions involve the relevant generation plant parameters for existing and new entrant generation units and their assumed behaviour in the market. These inputs include assumptions around generator offer profiles, generator heat rates, fuel costs, fixed and variable operating and maintenance costs, emissions, new entrant technology capital costs, outage rates, marginal loss factors, maintenance periods and more.

- Demand modelling involves assumptions around the peak demand and annual energy projections for different growth scenarios, uptake of rooftop solar PV, EVs and behind-the-meter battery storage. Future half-hourly profiles for each of these components are modelled by EY, using historical profiles for demand and rooftop PV, an assumed time-of-day profile for EVs and modelled behind-the-meter battery storage charging and discharging based on an expected contribution to peak demand and daily energy utilisation.

- Network capability defining power transfer limits and network limitations that constrain the physical dispatch of generator units and dispatchable loads. These are input in the form of a network constraint equation.[18]

- Renewable generation modelling involving assumptions around half-hourly generation profiles derived from locational wind and solar resource data and expected annual energy production.

- External assumptions around market policy drivers such as emissions reduction, the Reserve Capacity Mechanism (RCM), assumed wholesale electricity market design reforms. These assumptions are not necessarily used in the dispatch model explicitly but can influence the inputs that are.

2.3 Scenarios

A complete set of data and input assumptions collectively defines a scenario. In the context of this modelling, a scenario represents a plausible future with respect to the data and input assumptions that may impact development of wholesale electricity markets, but is independent of the constrained access regime that is employed (up to three cases are considered for each scenario, as described in Table 3). Certain metrics associated with the dispatch and market development outcomes will be more sensitive to particular input assumptions relative to others.

Figure 7 presents a diagrammatic representation of the input assumptions that make up a scenario.

Figure 7: High level overview of a scenario and possible settings

Scenario 'N'				
Peak demand	Energy consumption	Rooftop PV	Domestic storage	EV uptake
Government policy	Emissions reduction policy	Regulatory reforms	Technology CAPEX	Demand response
New entrant generators	Renewable bidding strategy	WACC	FOM	VOM
Other				

It is common to model multiple scenarios when undertaking market modelling as a test for robustness and/or to capture the wide range of possible outcomes that might eventuate. Modelling a number of different scenarios recognises that the future is inherently uncertain and a wide range of plausible outcomes may eventuate depending on the actual development of the market and the

[18] A network constraint equation is used by the dispatch engine to manage power flows across the transmission network by dispatching generation on or off for a particular constraint.

input assumptions that drive it. Modelling multiple scenarios provides the data to quantify the materiality of these changes and the sensitivity of outcomes to changes in scenario settings. The suite of scenarios to be modelled are developed giving consideration to the modelling objective and these sensitivities. The scenario settings proposed for this modelling and the rationale is discussed in Section 4.1 in further detail.

2.4 Simulation parameters

The potential for any particular outcome in the electricity market is probabilistic. Various combinations of prevailing customer demand, availability and costs of conventional and intermittent generation, energy storage devices, demand side participation, transmission network capability and generator availability will influence market outcomes.

Within a single scenario, Monte Carlo simulations of generator outages, multiple reference years of historical data and consideration to probability of exceedance (POE) peak demand forecasts are all taken into account. This captures the probabilistic nature of key half-hourly variations in the market in the overall outcomes reported.

Each Monte Carlo simulation iteration models different profiles of unplanned outage events on generators according to assumed outage rate statistics. Each of the scenarios modelled simulate 25 Monte Carlo iterations of generator outages for the Study Period, for each demand and reference year modelled. For this Project, EY modelled two reference years for atmospheric conditions and load shape and to manage the problem size, we limited POE peak demand samples to 10% and 50% POE scenarios. All simulated iterations of half-hourly results are collated with results reported on a weighted-average between iterations.[19] Table 4 provides a summary of key simulation parameters.

Table 4: Simulation parameters

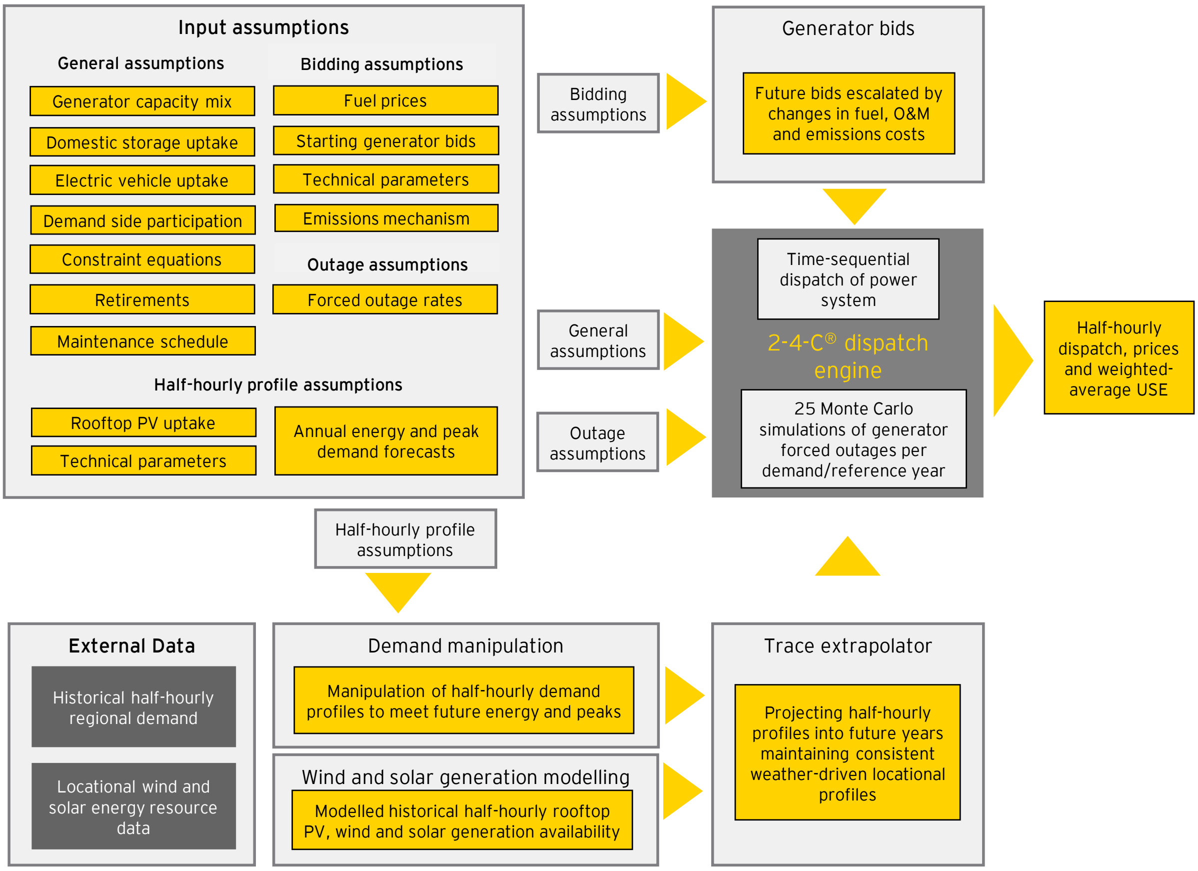
Simulation parameter	Description
Demand profiles	For each future simulation year, both the 10% POE and the 50% POE values for each forecast were modelled. Results are presented as a weighted average from the two profiles.
Reference years	The 2015-16 and 2016-17 reference years were modelled. Applying different reference years captures variability in terms of the half-hourly demand, wind and solar profiles according to the weather patterns in those years.
Monte Carlo iterations	On each demand profile we modelled 25 Monte Carlo iterations[20] of generator unplanned full and partial outages.
Results	All results are provided as a weighted average over all 100 iterations, except those comparing the outcomes for each of the reference years, which are a weighted average of 50 iterations. The 100 iterations are made up of two reference years, each with two demand profiles, each with 25 Monte Carlo iterations of forced outage profiles (as described above).

[19] EY applies a rounded 0.3 weighting on all 10% POE outcomes and 0.7 weighting on 50% POE outcomes as described in Appendix C. All modelled Monte Carlo iterations and historical reference years are considered equally likely.

[20] 25 iterations of Monte Carlo simulations produces converged revenue outcomes suitable for the purposes of the modelling

Figure 8 shows a consolidated flow diagram detailing the interactions between 2-4-C®, input assumptions, external tools and simulation parameters.

Figure 8: Data flow diagram for the market simulations



3. Modelling process

3.1 Overview

The modelling process for this Project is split into the following four stages:

- **Stage 1: Define and prepare the scenario input assumptions.** In this Project, the assumptions were developed through a public consultation process in March 2018 and through consultation between EY and the PUO. An overview of the input assumptions is provided in Section 4.1 and in detail in Appendix B.

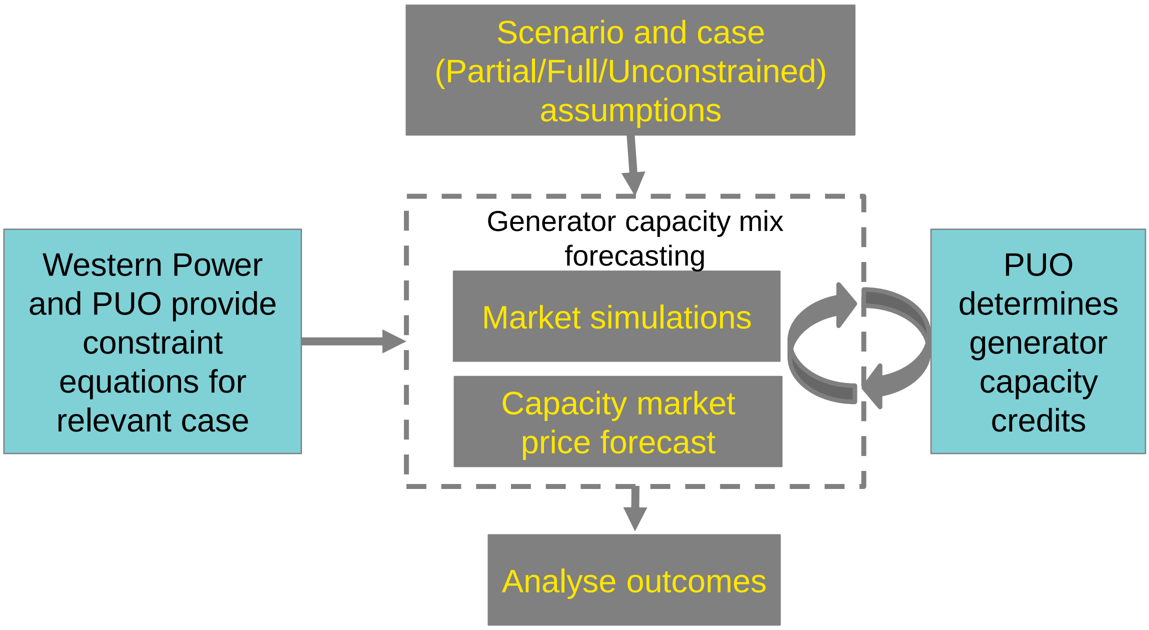
- **Stage 2: Generator capacity mix forecasting.** EY's methodology for forecasting the generator capacity mix involves iterative, time-sequential market simulations to forecast new entrants and retirements of generators in the WEM over the Study Period. This process involves an additional iterative feedback loop following capacity credit allocations performed by the PUO. Generator capacity mix forecasting is conducted separately for the Fully Constrained, Partially Constrained and Unconstrained Access cases, and is described in Section 5.

- **Stage 3: Conduct market simulations.** For each case perform a final simulation of market dispatch based on the generator capacity mix forecast. EY's model and approach to this is described in detail in Section 6.

- **Stage 4: Analysis and reporting.**

Figure 9 presents a general overview of the modelling methodology used for each scenario.

Figure 9: Overview of modelling methodology



3.2 Results analysis metrics

Table 5 provides a summary of the key data metrics presented in this Report to assess the overall impact of the transition to constrained network access. Each of these metrics are reported on an annual basis, i.e., for each forward-looking financial year over the Study Period.

Table 5: Key data metrics for reported on a financial year basis[21]

Category	Key metrics reported on	Units
System outcomes	WEM balancing market prices (time-weighted)	$/MWh
	Reserve capacity price	$/MW capacity credit
	Total fixed and variable operation and maintenance costs for the SWIS	$m
	Expected unserved energy (involuntary load shedding)	% sent-out energy
	Voluntary load shedding outcomes (demand-side participation)	MWh
	Proportion of trading intervals during which each constraint equation binds or violates	% of trading intervals
Generator outcomes[22]	Capacity factor	%
	Capacity credit assignment[23]	Capacity credits
	Net revenues	$m

[21] A single capacity year in the WEM is defined from 1 October to 1 October of the following calendar year. EY reports revenue outcomes based on a financial year basis. For simplicity, the capacity revenue is calculated on a financial year basis assuming that the assignment of capacity credits and the calculated RCP is equal to the values in the corresponding capacity year.

[22] Outcomes for existing generators in this Report are presented at a regional aggregate level. The PUO is consulting with individual generators private to discuss specific generator outcomes.

[23] This is not an explicit output from the 2-4-C® simulations. These are values are provided by the PUO.

4. Scenarios and input assumptions

4.1 The modelled scenarios

To explore the potential impact of a Fully Constrained Access regime in the WEM against the alternative option of a Partially Constrained Access regime and subsequent return to the firm access regime a number of scenarios were examined to account for uncertainties in future electricity demand and supply conditions. The scenarios were developed by the PUO, in consultation with EY and based on feedback received through a public consultation process held by the PUO in March 2018. Table 6 provides an overview of the two scenarios selected by the PUO that are presented in this report. Apart from demand forecasts, the scenarios use a consistent set of input assumptions, including individual generator technical parameters and costs. Demand assumptions are based on the Australian Energy Market Operator's WEM Electricity Statement of Opportunities forecasts. These are described in detail in Appendix B of this Report.

Table 6: Overview of the scenarios

Assumption	Base Scenario	High Scenario
Demand forecast	Expected[24]	High[25]
Study Period	1 July 2022 – 1 July 2032	

4.1.1 Rationale of the chosen scenarios

The objective of this modelling is to estimate the impact of transitioning to a constrained network access regime and the impact of network constraints on market outcomes. Scenarios were chosen based on whether they would result in material differences in new entrant capacity and generation curtailment outcomes.

For this modelling, the level of demand is considered to have the most significant impact on constrained access outcomes as it is a factor in determining potential constraints as well as the volume of dispatched generation.

On this basis, a high demand scenario was chosen as a suitable alternative as it explores a higher level of future demand as well as the impact of a stronger uptake of small-scale technologies including rooftop PV, behind-the-meter battery storage and EVs.

[24] Uses the expected demand scenario as published by AEMO in the 2018 WEM Electricity Statement of Opportunities (2018 WEM ESOO). https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities

[25] Uses the high demand scenario as published by AEMO in the 2017 WEM Electricity Statement of Opportunities (2017 WEM ESOO). https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities

4.2 Overview of input assumptions

Table 7 shows an overview of the key input assumptions for each scenario modelled. The table provides justification for each assumption. The input assumptions are presented in more detail in Appendix B. Following this table is a list of changes made to the assumptions compared to the methodology and assumptions report published as part of the industry consultation in March 2018.

Table 7: Overview of key assumptions for the core scenarios

Input assumption	Data source and value	Justification
Input assumptions affecting demand / energy consumption		
Electricity demand - energy and peak demand	AEMO's 2018 WEM ESOO[26] Expected scenario (Base Scenario) AEMO's 2017 WEM ESOO[27] Expected scenario (High Scenario)	This 2018 WEM ESOO contains the latest demand outlooks published for the WEM. However, the High Scenario was completed prior to the release of the 2018 WEM ESOO and as such uses the 2017 WEM ESOO Expected outlook. The 2017 ESOO Expected outlook is higher than the 2018 ESOO High outlook as shown in Section B.1.
Rooftop PV uptake	As above.	As above.
Behind-the-meter storage uptake[28]	As above.	As above.
EV uptake[29]	As above.	As above.
Reserve Capacity Target (RCT)	As above.	As above.
Assumption regarding market policies		
Large-scale Renewable Energy Target (LRET)	No change to the present legislated national target[30] of 33,000 GWh by 2020 and constant until 2030. WA's assumed contribution to the LRET is as per renewable capacity list.	There is currently no indication in the public domain that the LRET will not continue and be fulfilled. The current expectation is that LRET obligations will be largely met by generation projects built in the NEM.
Emissions reduction policy	No explicit policy, or carbon price.	There is currently considerable uncertainty surrounding new emissions reduction policies in Australia.

[26] 2017 Electricity Statement of Opportunities for the WEM
[27] 2017 Electricity Statement of Opportunities for the WEM
[28] Formulation of the charging and discharging profiles are described in Section 6.1.2
[29] Charging profiles are described in Section 6.1.3
[30] Available at: https://www.legislation.gov.au/Details/C2016C00286

Input assumption	Data source and value	Justification
External assumption affecting market supply		
New renewable capacity connected by 2022	List of named new entrant renewable projects assumed to be installed by 2022 as part of the WEM's contribution to the LRET.	Each project has an advanced status in the public domain, such as having an offtake contract and/or funding and network access.
Thermal generator developments	Synergy's announced thermal generator retirements.[31] Units retire at 50 years of age based on information on their first year of operation[32] (Base and High scenarios).	Based on committed and announced retirements. Generator units retiring at 50 years representing assumed maximum asset life.
External assumption affecting market supply continued		
Generator offers	Benchmarking process as part of this Project developed by EY.	Based on model benchmarking outcomes.
Generator outage rates (Forced and planned)	IMO Planning Criterion review.[33]	Publicly available data based on IMO assessment of SWIS data.
Fuel prices	2017-18 margin peak and margin off-peak review.[34] 2017 Gas Statement of Opportunities:[35] Base scenario	Publicly available information on fuel prices.
New entrant parameters including technology capex	AEMO's NTNDP 2016 with adjustments to wind and solar in early years in line with recent public announcements, plus CSIRO/Jacobs 2016 storage capex neutral trajectory.	The most up-to-date published technology parameters and capex estimates from market data.
Weighted-average cost of capital (WACC)	IPART Review of Regulated Retail prices (Aug 2015),[36] adjusted by EY for a higher assumed gearing ratio: pre-tax, real WACC of 7.5%.	Agreed between EY and the PUO as an applicable WACC for generation investment.

[31] Synergy announcement - 380 MW retirement
[32] Western Power Annual Planning Report 2011
[33] IMO Planning Criterion review
[34] AEMO 2017-Margin-Peak-and-Margin-Off-Peak-Review-Assumptions
[35] WA-Gas-Statement-of-Opportunities 2017
[36] iPART Spreadsheet_of_WACC_model_-_August_2015

Input assumption	Data source and value	Justification
External assumptions regarding network and market design reform		
Network augmentation	Committed and very advanced[37] network augmentations.	Including uncommitted network augmentation projects may understate congestion outcomes.
Regional reference node (RRN)	RRN assumed to be at the Southern Terminal 330 kV node.	While a policy decision to locate the RRN at Southern Terminal has not yet been made, locating the RRN at Southern Terminal reflects the benefits of locating the RRN at a major load centre rather than a generation centre.
Marginal loss factors (MLF)	As provided to EY by the PUO. The new entrant MLF assumptions are described in Section B.12.	The calculation of loss factors is based on the RRN at a demand centre location with historical data.

The following points summarise the changes to the assumptions used in the modelling compared to what was published in the methodology and assumptions report as part of the industry consultation in March 2018.

- **Scenarios**: The scenarios presented explore changes in supply and demand balance outlook focussing on the relative impact on generator dispatch due to alternative network access frameworks.
- **Demand outlooks**: The scenarios were originally proposed to use the demand outlooks from AEMO's 2017 ESOO. As AEMO's 2018 ESOO was published during the modelling, the Expected outlook from the 2017 ESOO is used in the High Scenario and the Expected outlook from the 2018 ESOO is used in the Base Scenario.
- **LGC prices**: For the purposes and assessing the total market payments and individual generator revenues, the methodology and assumptions paper stipulated an assumption of $40/LGC for all renewable generators installed prior to 2022. However, for the outcomes presented in this Report, the PUO opted, in consultation with EY, to assume an LGC value of $30/LGC for existing renewable generators and $15/LGC for the assumed new entrant GIA renewable generators. This adjustment takes into account the apparent recent fall in LGC prices as well as potential existing renewable generators to roll off their present contracts.
- **Generator outage rates**: The numbers written in the original methodology and assumptions report were incorrect, whilst they are correct in the published accompanying assumptions Excel workbook. These numbers have been corrected in this Report.
- **Assumed marginal loss factor for new entrant wind and solar generation in East Country and Eastern Goldfields**: these have been made dynamic and depend on the total installed capacity of wind and solar PV in these regions. The details are described in Section B.12.

[37] Committed and very advanced network augmentation projects are defined by Western Power. Committed projects are discussed in the Western Power Annual Planning Report 2017. EY has not verified the status of these projects.

- **The exclusion of large-scale storage.** Large-scale storage was originally considered for potential inclusion in the modelling. However, in consultation with EY, it was decided by the PUO not to include the technology in the modelling due to the increased complexity that would result from its inclusion, and it being determined not to be a material factor in the outcomes with respect to forecasting the impact of Fully Constrained Access compared to the other cases. The exclusion of large-scale storage was traded off with focusing more on other more material factors such as the impact of the different constrained access regimes on capacity credit allocations and allowing more iterations between the PUO's capacity credit calculations and EY's economically-driven capacity mix forecasting to ensure the drivers are modelled accurately and in detail.

In addition to the above assumption changes, some further refinements to the methodology have been made since the draft outcomes were published by the PUO's report on 9 August 2018.[38] Primarily, during one on one consultation with market participants and Western Power, the PUO was advised of network limitations at Kwinana Terminal, which effectively limit the amount of gas turbine capacity that can be installed in that location. The PUO understands the network limitations are caused by fault levels approaching the maximum equipment capability. These limitations are discussed in Western Power's Annual Planning Report.[39]

As network constraint equations cannot be used to de-commit a generating unit they are unsuitable as a mechanism to manage fault level limitations. Because of this, the set of network constraint equations used in the market modelling did not adequately capture upper limits on the capability for Kwinana Terminal to accommodate new entrant generation capacity. Western Power subsequently advised the PUO of indicative upper limits on new entrant generation capacity at Kwinana Terminal 132 kV and 330 kV connection points as 100 MW and 350 MW, respectively. The PUO had previously assumed all new entrant generation at Kwinana was connected at 132 kV.

EY repeated the market simulations for the base scenario accounting for the revised upper limits on new entry at Kwinana. The simulations result in a reallocation of some new entrant gas generation capacity previously connected at Kwinana 132 kV to the 330 kV bus, as well as to Kemerton and the Eastern Goldfields. Some other minor changes are also forecast for the generation capacity. The outcomes are presented in Section 7.

[38] http://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Consultation-Paper-Two-Improving-access-to-the-Western-Power-Network.pdf

[39] https://westernpower.com.au/about/reports-publications/annual-planning-report-2017/ (Section 6.1.1)

5. Generator capacity mix forecasting

5.1 General

The term 'generator capacity mix' in this Report refers to the overall mix of generators of different technology types and at different locations that is forecast to be installed in the WEM during the Study Period.

In each scenario and case, EY forecast the economically-driven generator capacity mix as an outcome of the assumptions used.

5.2 An iterative approach

For this Project, the procedure employed by EY to forecast the generator capacity mix involves running multiple market simulations with the 2-4-C® model together with separate capacity credit allocations calculated by the PUO to arrive at a final set of outcomes. The process involves the following steps:

1. **Determine a set of input assumptions.** A summary of the input assumptions used for each scenario is provided in Section 4.2. The various input assumptions impact different aspects of the market modelling in different ways and to varying degrees. Section 6 details how several of these input parameters are used within a market simulation.

2. **Set up an initial market simulation.** Using all the assumptions, conduct an initial time-sequential half-hourly market simulation over the Study Period using the constraint equations formulated for the case being modelled. Section 5.2.1 discusses modelling network constraints in the generator capacity mix and potential impacts on market development.

   Assess the commercial viability of each generator using the method of calculating net revenue described in Section 5.2.1 to determine if any new entrants or retirements would be commercially driven for net revenue outcomes outside a tolerance range.

3. **Iterative modelling to achieve final simulation**. Adjust the new entrants and retirements; re-simulate several times until all generators have a net revenue within ±$2/MWh in all simulation years.

   For example, if a new entrant generator is installed in response to price signals observed in the previous simulation but fails to make positive net revenue in the next simulation iteration for multiple years after it is in-service, it is removed (or reduced in size) from the generator capacity mix as it is considered not commercially viable.

   Retirements can be driven by age considerations (e.g., a coal fired power station reaching 50 years of age) or when the generator makes a loss for consecutive years of operation. It is assumed that when wind and solar PV generators reach their project lifetime, the sites are upgraded to new wind and solar PV generators.

   Since wind and solar PV generators are typically capital intensive investments with very little ongoing costs, it is considered very unlikely that a wind or solar PV farm would be retired for economic reasons. As such EY does not consider retirements of wind and solar PV generators in the modelling.

4. **Capacity credit allocation by the PUO and finalisation of generator capacity mix.** The total installed capacity and allocation of capacity credits is checked against the RCR. This is discussed in Section 5.2.3. Final capacity credit allocations for constrained access are calculated by the PUO based on the final generator capacity mix. If material changes are required after assessing the impact on RCR, Reserve Capacity Price (RCP) and generator

capacity outcomes, EY adjusts the new entrants and retirements[40] before finalising the generator capacity mix.

5.2.1 Modelling network constraints in the generator capacity mix

Whether a generator can be constrained off or on may impact the development of generator capacity in the market. This is accounted for in the modelling by forecasting generation development using the two constraint equation sets provided to EY.

Table 8 provides an overview of which generators can be constrained by the market dispatch engine in the two cases.

Table 8: Overview of the treatment of generators when undertaking generator capacity forecasting

Case	Treatment of existing generators with access rights, from July 2022	Treatment of existing generators with no access rights, from July 2022	Treatment of all new entrant generators not currently connected
Partially Constrained Case	Cannot be constrained off[41] Can be constrained on	Can be constrained off/on	Can be constrained off/on
Fully Constrained Case	Can be constrained off/on		
Unconstrained Access Case	No network constraints apply		

All future new entrant generators and existing generators currently connected with no access rights can be constrained off and on (if dispatchable) in both cases by the market dispatch engine.

Incumbent generators with network access rights cannot be constrained off by the dispatch engine in the Partially Constrained Case.[41] This can result in a situation where despite it being potentially more economical to constrain off an incumbent generator to relieve network congestion, another generator is constrained off instead, impacting on generation revenues and market development outcomes. Although generators with network access rights cannot be constrained off in the Partially Constrained Case they can be constrained on to avoid violation of a network limitation if required. Constrained-on payments will be quantified in these circumstances.

5.2.2 Calculating a generator's net revenue

Generator capacity developments made within the market modelling procedure are determined by assessments of the net revenue of generators modelled within 2-4-C® and the interactions with the capacity market. A generator's net revenue is calculated for any particular year using the equation (1) below.

$$\begin{aligned}\text{Net revenue} = {} & \text{pool revenue} + \text{capacity payment} + \text{LGC revenue} + \text{constrained-on payments} \\ & - \text{O\&M costs} - \text{capital cost repayment} - \text{fuel costs}\end{aligned} \tag{1}$$

[40] This process will be conducted once and towards the end of the iterative generator capacity mix forecasting process allowing the capacity mix to be potentially refined based on the assignment of capacity credits to each facility.

[41] Due to the present unconstrained planning framework adopted by Western Power, the incidence of generation being constrained during system normal conditions is rare. Despite this, the potential remains for generation to be constrained from time to time to accommodate planned and forced network outages, such as during a period of a transmission line outage or for system security events. AEMO manages this in accordance with the WEM Rules. The potential for these events remains in the status-quo access environment, or whether transitioning to the Partially Constrained Case or the Fully Constrained Case. As such, EY's forecast modelling does not take such contingencies or events into account as they are possible in all access environments and the relative financial impact is negligible.

Where:

Pool revenue is the total annual wholesale market revenue earned over each trading interval in the year. In the modelling, this is the sum-product of the modelled dispatched generation and the wholesale market price over all trading intervals, multiplied by an assumed loss factor for the generator.

Capacity payment is the total annual capacity payment earned over the year.[42] In our modelling, this is equal to the amount of capacity credits allocated to a particular facility taking into account the impact of constrained access, multiplied by the calculated RCP for that year. This is discussed in Section 5.2.3 and 5.2.4.

LGC revenue is the total annual revenue earned associated with the sale of LGCs. With the Study Period starting on 1 July 2022, EY believes there is a high certainty that the LRET will be met by this time. The specific renewable projects commissioned in the WEM that contribute to the LRET are assumed for each scenario (as presented in Table 18 in Appendix B.8). With the LRET met, all new entrant generators commissioned in the WEM within the Study Period are unlikely to receive LGC revenue and as such EY assumes this revenue source is zero. For the purposes of estimating the impact of the Fully Constrained Case on the LGC revenue on existing renewable generators, the PUO opted, in consultation with EY, to assume an LGC value of $30/LGC for existing renewable generators and $15/LGC for the assumed new entrant renewable generators installed by 2022. Most existing renewable generators have power purchase agreement contracts with various agreed values for LGCs that are not available in the public domain.

Constrained-on payments is a mechanism in the WEM where generators are compensated for being constrained-on at balancing market prices below their short-run marginal cost (SRMC).[43]

O&M costs is the total fixed and variable operation and maintenance costs. The variable operational costs do not include an emissions cost based on the proposed scenario assumptions to date.

Capital cost repayments is the annualised capital cost of the generator, taking into account the assumed economic life and WACC for the study.

Fuel costs is the total cost of the fuel used in the generator's modelled production of electrical energy throughout the year. The fuel cost is always zero for wind and solar PV.

Constrained-off payments will not apply in a fully constrained access regime when a generator is constrained-off due to network constraints.

Ancillary service revenues are excluded from generator net revenue calculations. The co-optimisation of energy and ancillary service markets is a part of the essential reforms outlined by the PUO.[44] Whilst we consider that it is an important consideration, it is also secondary to the focus of this investigation and scope of work. Of the current ancillary services required in the WEM, load following, spinning reserve, and load rejection reserve are the services that may be impacted by a transition to constrained network access. Whilst it is possible to model the impact of constrained access on ancillary service markets, we consider that the overall benefit in quantifying the impacts will be second order compared to outcomes associated with the curtailment of energy in the balancing market and potential impacts on capacity credit allocations and RCP. EY includes the impact of ancillary service participation in the offer behaviour of generators in the market modelling, but did not explicitly conduct any modelling of the ancillary services themselves.

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[42] A single capacity year in the WEM is defined from 1 October to 1 October of the following calendar year. EY reports revenue outcomes based on a financial year basis. For simplicity, the capacity revenue is calculated on a financial year basis assuming that the assignment of capacity credits and the calculated RCP is equal to the values in the corresponding capacity year.

[43] Constrained-on payments are made to compensate generators for being dispatched in bid bands where they offer higher than the pool price. The calculation of constrained-on payments is discussed in Section 4.1.2.

[44] Improving access to Western Powers network – Consultation Paper

Assessing a generator's net revenue is conducted differently depending on whether it is an existing or a new entrant:

- **Existing generators**: There is no publicly available data for an existing generator's capital cost repayments and in many cases the capital cost might be already paid off. As such EY assesses the year-on-year net revenue of existing generators in the modelling assuming no capital cost repayments are required, and retires them on a commercial basis if the net revenue is negative (and persists with negative revenue in subsequent years).

- **New entrant generators**: Commercially driven new entrant decisions are based on the net present value (NPV) of a generator's net revenue over its assumed economic lifetime. Since the Study Period modelled is only until 1 July 2032, each generator's net revenue is extrapolated by repeating the final year in order to calculate an NPV of its assumed economic lifetime.

5.2.3 Reserve capacity requirement

The relevant RCR for a particular capacity year is based on meeting the Long Term Planning Criterion by ensuring sufficient generation capacity is available to meet peak demand, a reserve margin, load following requirements and intermittent loads.[45]

The RCR for each scenario is set taking into account the 10% POE peak demand assumption for that scenario. An initial assessment of capacity credits is allocated to each generator assuming unconstrained access and an assessment of historical outcomes of technology types. This initial capacity credit allocation for existing generators is based on the latest WEM capacity credit figures published by AEMO for 2019-20.[46] EY also calculates the relevant levels for wind and solar PV generators consistent with WEM Rules.

In determining whether the installed capacity in the SWIS meets the RCR in a constrained access environment, EY uses the total capacity credit allocations as calculated by the PUO. The total capacity credits is also used to forecast the capacity market price.

The PUO calculated the capacity credit allocation based on the methodology proposed in the consultation paper "Allocation of capacity credits in a constrained network". This is consistent with the principles of the Relevant Level calculation in the Market Rules but modified to account for the impact of constrained access.

[45] It is noted that whilst the Long Term Planning Criterion is reviewed every 5 years, it is assumed that it remains for the length of the study. No change is assumed to this criterion when assessing the reserve margin. Load following requirements and intermittent loads are assumed to remain constant throughout the period. The RCT must also be sufficient to ensure the reliability standard of 0.002% of USE is met.

[46] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Assignment-of-capacity-credits

5.2.4 Calculating capacity payments

The RCP is the administered price for all capacity that is not bilaterally traded in the WEM. EY applies the RCP to all generators assuming that the RCP influences contract prices in a similar way to balancing market prices affecting the energy price negotiated in an off-take contract.

The following formula from the Market Rules applies:

$$\text{RCP} = \text{MIN}\left\{\left(\frac{\text{BRCP} \times \text{'Intercept'}}{1 - \left((\text{'Surplus'} + 0.03) \times \text{'Slope'}\right)}\right), \text{BRCP} \times 1.1\right\}$$

Where:

BRCP is $139,154/MW and denotes the benchmark reserve capacity price[47]

The 'Intercept' term is used to adjust the price curve so that it passes through the BRCP at the RCR

The 'Surplus' term relates to the number of capacity credits assigned in excess of the RCR, expressed as a percentage of the RCR

The 'Slope' term is a negative number to be steepened over time putting downward pressure on the RCP for any given level of surplus.

For the length of the Study Period, RCP is calculated based on the values for 'intercept' and 'slope' as per the Reserve Capacity Administered Price table. The surplus value is calculated based on the capacity credits available in the market and the initial allocation discussed in Section 5.2.3. The RCP calculation does not include modelling a capacity auction. Proposed reforms to the RCM will be publicly consulted on by the PUO in the future.

[47] The BRCP was obtained from https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Benchmark-Reserve-Capacity-Price and has been reduced due to CPI conversion. If a higher BRCP were used, additional new entrant OCGT capacity would be forecast to be installed and the forecast capacity market price would be similar to the outcomes presented in this Report.

5.2.5 Calculating constrained-on payments

The existing Market Rules allow for generators to be constrained-on by AEMO in response to system security limitations. A constrained-on generation payment is paid on the amount of 'Upwards Out of Merit Generation' as defined in the Market Rules. The PUO have identified that this payment is to be retained in the WEM.[48]

To determine the constrained-on payments received by a generator for a market simulation, EY collates the trading intervals where the generator is dispatched at a balancing market price that is lower than their offer for that generation. All the dispatched generation that is offered at prices (adjusted for the generator's loss factor) greater than the balancing market price in that trading interval is the constrained-on generation. The constrained-on payment is equal to the price as offered for the constrained-on generation, minus the balancing market price, multiplied by the constrained-on generation and the loss factor of the generator. In any given trading interval this could apply to generation offers in multiple price/quantity bands.

Equation (2) describes the calculation of the total constrained-on payment for a generator over a simulated year.

$$Y = \sum_{k=1}^{N}\left(P_k \times \sum_{u=1}^{W}[G_u \times M_u]_k\right) + \sum_{k=1}^{N}\sum_{i=1}^{J_{k,u}}\left(\left[b_{i,u} - P_k\right] \times {g^+}_{i,u,k} \times M_u\right) \tag{2}$$

where:

k represents each trading interval out of the total number of trading intervals simulated for the year, N

u represents each generator out of the total number of generators, W

i represents each bid band (price-quantity pair) at which there constrained-on generation is offered up to the total number of applicable bid bands for each trading interval and generator, J,k,u, and

${g^+}_{i,u,k}$ is the applicable constrained-on generation applying to the offered price, i, generator u and trading interval, k.

[48] Improving access to Western Power's network – Consultation paper

5.3 Modelling limitations

Whilst the scenarios presented capture a range of potential future evolutions of the WEM over the Study Period, there are other scenarios that could transpire and lead to materially different outcomes.

Aside from uncertainty in the input assumptions, some other key limitations in the modelling methodology are:

- Network upgrades or augmentations were only considered where they were deemed necessary from a power system reliability point of view, as is the case in the High Scenario. If a network upgrade were to be built that would alleviate network constraints in the Mandurah area or the fault level limit in Kwinana, the outcomes in the scenarios may be materially different. The Unconstrained Access Case also accounts for network augmentations, where these are required to ensure no generator can be constrained off in system normal conditions.
- The PUO's capacity calculator can reduce capacity credits allocated to generators as a result of generation from other generators being constrained on. This has been identified in the case of generators at the Kwinana 132 kV location being constrained on to meet peak demand and resulting in generators in North Country receiving reduced capacity credits in the Partially Constrained Access cases. An alternative outcome to this is being considered by the PUO in such cases, but this was not factored into the outcomes presented in this Report.
- The constraint equation formulation is based on system normal N-1 conditions, which are designed to ensure power system security in the event of any single contingency. However, in the actual market, AEMO may invoke additional or alternative network constraint equations during periods of transmission network outages or other events. This could lead to alternative dispatch and balancing market price outcomes during these periods. The modelling does not consider such events.
- Ancillary services were not explicitly modelled, including the load following ancillary services (LFAS) market. As such the impact of constrained access on ancillary services was not considered.
- The modelled dispatch is based on a least-cost dispatch algorithm with the Synergy units disaggregated, with generator offers that attempt to emulate the present dispatch behaviour of each individual generating unit. The offer (bid) profiles were developed in a benchmarking exercise on the 2016-17 financial year. This approach effectively maintains the status quo in terms of generators providing ancillary services such as load following and spinning reserve, and does not allow for potential changes to the requirements for those services throughout the Study Period. However, it is considered that capturing the impact of dynamic participation by generators in ancillary services would not have a material impact on the outcomes presented in this Report
- All generators were assigned a fixed assumed marginal loss factor (MLF) across the Study Period, with the exception of new entrant wind and solar generators in East Country and Eastern Goldfields, which were assigned a formula-driven MLF that depends on the amount of wind and solar PV capacity installed in each of those regions.[49] The MLF for all new entrants is based on an MLF from an existing generator electrically nearby. If the MLFs were modelled explicitly they could potentially be forecast to change materially from the assumed MLFs and from year to year across the Study Period. This could result in different capacity mix forecasts to those presented.
- A single static number was assumed for each generator's heat rate, so the modelling does not take into account a generator's state of operation on its heat rate and associated short-run marginal cost. This is not considered to have a material impact on the outcomes presented in this Report.

[49] This is due to these two regions being considered to have MLFs that are much more impacted by the total capacity installed in those regions than in other regions in the WEM. The formula derived for each is described in Section B.12.

6. Market modelling methodology

This section describes the methodology associated with the different aspects of market modelling including the market simulations that produce forward looking half-hourly generation dispatch and wholesale electricity prices.

6.1 Forward-looking half-hourly modelling

EY's approach to the forward-looking half-hourly modelling in this Project is to base all the inter-temporal and inter-spatial patterns in electricity demand, wind and solar energy on the weather resources and consumption behaviour in two historical years (reference years).

Figure 10 (following page) depicts EY's methodology.

The top section of Figure 10 on the following page highlights the rationale behind what features in the historical half-hourly data are projected forward, and what features are modified to capture future conditions. These are described in more detail as follows:

- The historically observed **inter-temporal and inter-spatial impact of weather patterns** are maintained in the forecast. Historical hourly locational wind and solar resource data is used by EY to model half-hourly[50] generation from rooftop PV, large-scale solar PV[51] and wind generation. All the correlated interactions between wind and solar generation at different sites are projected forward consistently, maintaining the impact of actual Australian weather patterns. The available half-hourly large-scale wind and solar PV generation profiles are offered[52] into the market to meet grid demand in the 2-4-C® dispatch modelling. These may not be fully dispatched in case of binding network constraints or being the marginal generator and setting the price, with the volume above the marginal price being curtailed.

- **Inter-temporal and inter-spatial (regional) electricity consumption behaviour** is maintained in the forecast. Historical half-hourly operational grid demand[53] is obtained from AEMO and added to EY's historical modelled rooftop PV to produce the historical native electricity consumption. By projecting consumption forward instead of grid demand, EY maintains the underlying half-hourly consumer behaviour while specifically capturing the future impact of increasing rooftop PV generation in changing the half-hour to half-hour shape of grid demand during each day. EY also separately models behind-the-meter (domestic) storage profiles and EV charging profiles to capture their impact on the shape of grid demand without changes to the total underlying operational energy forecast by AEMO. As per AEMO's assumptions, EY assumes negligible contributions to peak demand from domestic battery storage and EVs.

- The historical year(s) used in the modelling consist of various types of weather, which may or may not be considered typical or average. With respect to demand, the historical electricity consumption is processed to convert it into two types of weather-years for each future year modelled. One could be considered a **moderate year**, which uses AEMO's 50% POE peak demand forecast,[54] while the other is considered a year with more **extreme weather**, using AEMO 10% POE peak demand.[55]

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[50] Hourly historical resource data is interpolated to half-hourly data.

[51] The same applies to solar thermal generation.

[52] EY's offer methodology is described in Section 6.1.4.

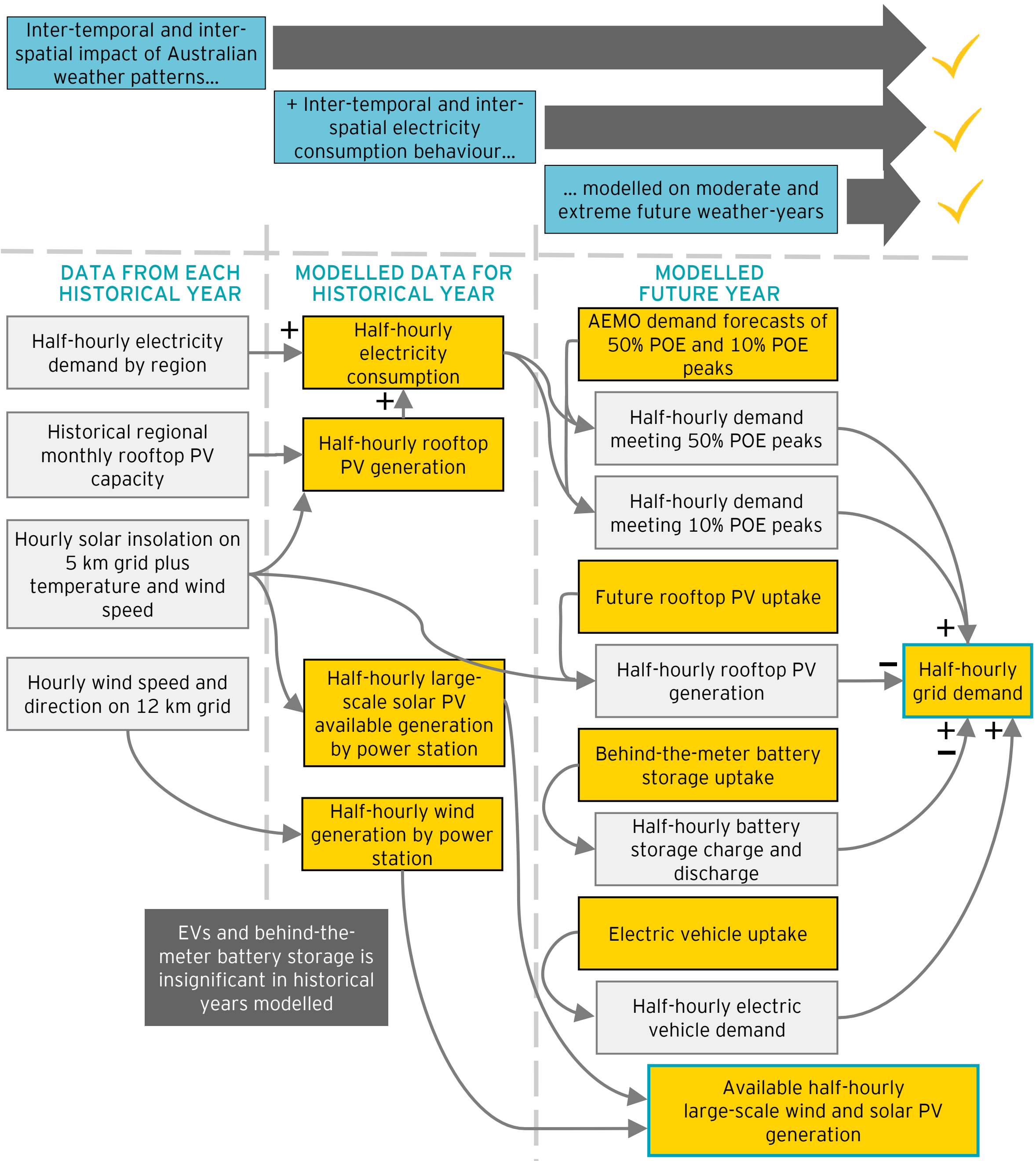
[53] Operational demand refers to the demand used by residential, commercial and large industrial customers, supplied by scheduled, semi-scheduled and significant non-scheduled generating units as defined in the NEM.

[54] The 50% POE peak demand forecast is expected to be exceeded for one half hour once in every 2 years.

[55] The 10% POE peak demand forecast is expected to be exceeded for one half hour once in every 10 years.

- Overall, the half-hourly modelling methodology allows for the underlying weather patterns and atmospheric conditions to be projected in the forecast capturing a consistent impact on demand, wind and solar PV generation. For example, a heat wave weather pattern that occurred in the historical reference year is maintained in the forecast for each future year. The forecast is developed in the context of a moderate or extreme weather year from a demand perspective. The modelled half-hourly availability of renewable generation during that event is a function of the assumed operational individual generators and the atmospheric conditions for each generator location as occurred[56] during the event.

Figure 10: Flow diagram showing EY's use of an historical year of electricity and atmospheric conditions data to make a half-hourly forecast



56 According to the resource data.

The methodologies to produce the forecast half-hourly demand, wind and solar profiles for the modelling are briefly described in more detail in the following sections.

6.1.1 Half-hourly locational renewable generation modelling

As described earlier, and depicted in Figure 10, EY models future half-hourly generation availability for forecast uptake of individual wind and large-scale solar PV power stations, based on historical wind and solar resource data. An overview of the methodology for wind and solar is as follows:

- **Wind:** EY's wind energy simulation tool (WEST) uses historical hourly short-term wind forecast data[57] from the Bureau of Meteorology (BOM) on a 12 km grid across Australia to develop wind generation profiles for existing and future potential wind power stations used in the modelling. WEST scales the BOM wind speed data for a site and processes this through a typical wind farm power curve to target a specific available annual energy in the half-hourly profile for each power station. The scaling is usually required to convert the modelled wind speed to the representative wind speed received by the wind farm. Existing wind farms use the historical average achieved annual energy from actual data, while all new wind farms use an assumed annual energy that varies depending on their location in the WEM For this Project, EY is assuming 44% for North Country and 39% for the rest of the WEM, based loosely on observed capacity factors.

- **Solar PV**: EY's solar energy simulation tool (SEST) uses historical hourly satellite-derived solar insolation data on a 5 km grid across Australia, obtained from the BOM, along with BOM weather station data of temperature and wind speed. The resource data from the BOM is processed using the System Advisory Model (SAM) from the National Renewable Energy Laboratory (NREL) to develop locational solar PV generation profiles. The annual energy output varies from site to site as a result of calibration to the performance of existing solar farms and the locational resource data.

6.1.2 Behind-the-meter battery storage

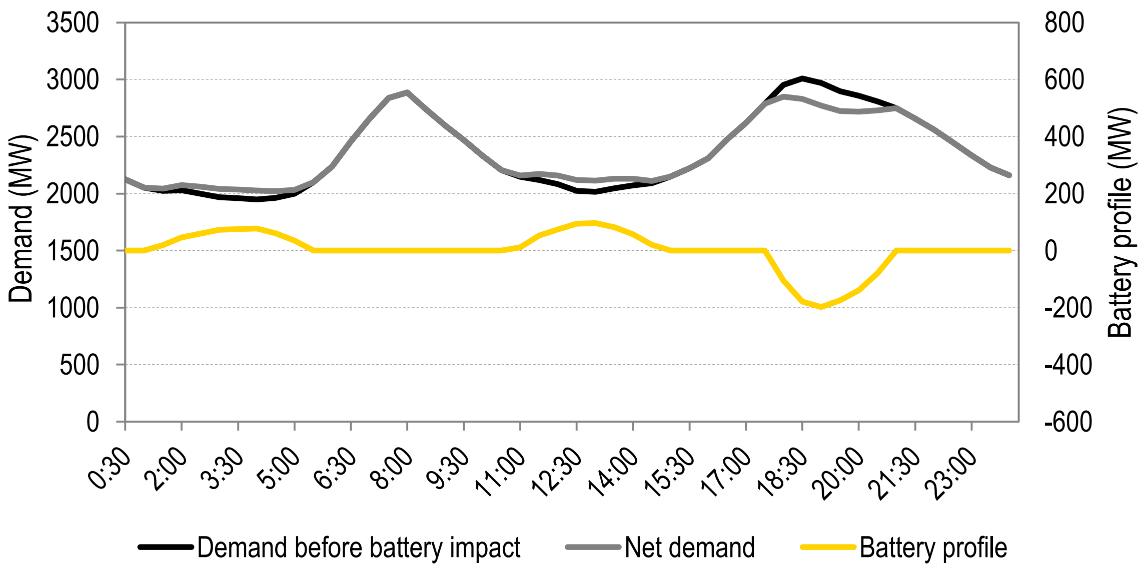
EY's behind-the-meter battery storage profile tool produces a seasonal time-of-day charge and discharge profile for behind-the meter battery storage for the WEM. The tool aims to produce an aggregate profile that responds to peak demand usage tariffs and lower priced daytime effective tariffs due to battery owners also owning rooftop PV systems. Rather than assuming a particular retail tariff structure for future battery owners, it is assumed that the tariffs will relate to the net demand profile on the distribution network – consumption minus rooftop PV generation. This is based on the rationale that future tariffs will be structured to incentivise battery owners to reduce the difference between the daily minimum and maximum demand as this provides a more optimal network usage. As a result the tool produces a fixed time-of-day discharge profile that reduces the seasonal peak net demand and a charge profile that operates during the lowest periods of residual demand.

EY has also incorporated imperfection into the aggregated profile of the batteries to meet the peak demand reduction forecasts as projected in the WEM ESOO scenarios.

[57] An historical hourly profile is comprised of many historical hourly forecasts made every six hours by the BOM throughout the historical years modelled.

Figure 11 below illustrates an example day in winter on how the aggregate battery charge and discharge cycle alters the operational demand profile.

Figure 11: Example day showing impact of behind-the-meter battery storage on operational demand in the WEM



This behind-the-meter storage profile is added/subtracted to the operational demand for 2-4-C® modelling. EY uses the same assumptions as AEMO, including that behind-the-meter battery storage has a negligible contribution to peak demand. Accordingly, the energy and peak-demand contributions of the battery storage profile is taken into account in the overall demand profile modelled. The amount of behind-the-meter storage modelled in each future year is provided by AEMO as part of the 2017 WEM ESOO demand scenarios. The trajectories used are shown in Appendix B.4

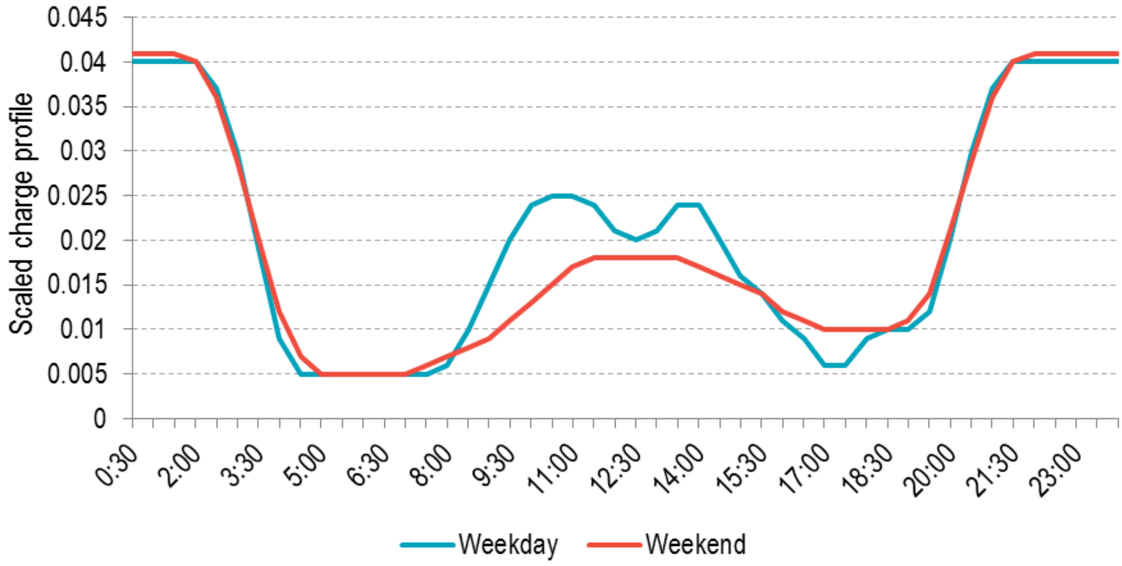
6.1.3 Electric vehicle demand

EY converts the annual energy expectation from EVs forecast by AEMO into half-hourly profiles to add to the grid demand used by 2-4-C®. The trajectories are provided in Appendix B.5

Little is yet understood on when EVs will be charged in aggregate. EY has developed two alternative time-of-day EV demand profiles, one for weekdays and one for weekends. These profiles assume that overnight charging rolls off early in the morning, followed by an extended low period during the morning period of high electricity demand and commuting activity. Charging then increases again after people arrive at their destinations, and persists throughout the day before decreasing again in the afternoon when commuting activity commences again. Overnight charging commences significantly after the evening peak demand driven by time-of-use and peak demand tariff signals.

Figure 12 below shows the assumed time-of-day average energy used by EVs in the modelling. EY uses the same assumptions as AEMO, including that EVs have a negligible contribution to peak demand. Accordingly, the energy and peak-demand contributions of the EV profile is taken into account in the overall demand profile modelled.

Figure 12: Percentage of daily energy use for EVs in each half-hour of the day



6.1.4 Generator offers

In the forward-looking simulations for this Project, EY uses a set of offer profiles for each generator that depict their typical offer behaviour as reflected in the market data, with respect to their SRMC. These offers were determined in a benchmarking exercise, as described in Appendix A. For most generators their offer behaviour can be represented with one static offer for a given SRMC and for others multiple offer profiles that apply to particular periods of time (such as off-peak and peak periods) to reflect patterns in varying operating conditions due to fuel availability or other reasons.

An offer profile for a generator may have up to ten bands of quantities of capacity at different prices (price-quantity pairs) taking into account energy price limits.[58] For example, a coal unit may typically offer a certain proportion of its load at a negative price or near the market floor price (-$1,000/MWh) to reflect the cost of restarting, plus incremental proportions of its capacity at positive prices to reflect their expected short-run marginal costs[59] that can vary based on their operating state and fuel costs.

In each forward-looking year in the Study Period, the offers for each generator are adjusted according to computed changes in their SRMC, which is based on the assumed annual applicable fuel price. These adjustments are only made to prices offered in a profile that are a function of the SRMC (i.e., this would not apply to offers near the market floor price). In the case that the most expensive SRMC of all generators increases due to the assumed fuel and/or emission costs for a given simulated year, EY increases the maximum energy price limits accordingly.

Since the operating conditions for most generators are confidential, EY determines suitable offer profiles for each generator using a benchmarking process. This involves simulating the half-hourly dispatch and prices for a historical year with 2-4-C®, and adjusting the offer profiles for each

[58] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits
EY's market modelling incorporates these settings into generator offers as well as in modelled price outcomes.

[59] The WEM Market Rules requires that all Market Participants offer capacity at or below the reasonable expectation of that generator's SRMC.

generator with an iterative process to reproduce actual dispatch and pricing outcomes as close as possible.

As part of this Project, EY conducted a benchmarking process on the 2016-17 historical year to determine the base offer profiles used in all the forward-looking market simulations for this Project. Key outcomes of the benchmarking process are provided in Appendix A of this Report.

Note that Synergy currently offers its Balancing Portfolio[60] into the market as a single set of price-quantity pairs. In EY's modelling, each generator unit is modelled explicitly including each generator in Synergy's Balancing Portfolio. Modelling individual generator units is also a requirement for modelling constraint equations, which are typically derived with respect to generator unit terms. As per the approach described above, EY's forecast modelling is consistent with individual facility offers rather than the present regime where a single set of offers is submitted for the collective Synergy portfolio.

6.1.5 Demand side management

Electricity consumption in the WEM has some inherent non-disclosed price response where some market-exposed consumers tend to use less power when prices are high. The impact of this is captured in AEMO's energy and peak demand forecasts modelled by EY. However, AEMO also publishes an amount of demand that is responsive to market prices, and these loads offer into the market.[61] The explicitly offering demand side management (DSM) loads are incorporated into 2-4-C® as it would in the actual market dispatch engine. Providers of DSM are also eligible for capacity credits. This is incorporated as an input into modelling the RCP based on the capacity credits assigned for DSM in AEMO's 2017 or 2018 WEM ESOO, depending on the scenario.

6.1.6 Transmission network constraints

Partially and Fully Constrained Access in the WEM are both taken into account in the dispatch process with network constraint equations. Constraint equations define the power transfer limits on transmission network assets and have been prepared by Western Power and the PUO consistent with AEMO's pre-dispatch formulation guidelines.

For this Project, Western Power formulated network constraint equations based on the existing network infrastructure in the SWIS, in addition to committed[62] network augmentation projects. Network constraint equations define the system normal network capability only as it is understood that existing unconstrained access entitlements only apply under these conditions.[63]

Constraint equations are derived from power flow studies undertaken by Western Power and are based on power system thermal limitations identified on its network. No sensitivity studies are being performed to account for constraints that may apply for other network conditions involving planned or unplanned outages. The PUO have advised that the current unconstrained access framework only applies for system normal conditions.

[60] Synergy's Balancing Portfolio consists of all Synergy's registered facilities other than what is defined in the Market Rules.
[61] https://aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-Electricity-Statement-of-Opportunities-for-the-WEM.pdf
[62] Committed network augmentation projects as per Western Power's Annual Planning Report 2017. EY has been informed that although not yet committed, Western Power is currently at advanced planning stages for a long term solution to relieve limitations associated with the APJ-PNJ line and expects to commit to a project in the near term. To account for the impact of this project the network constraints associated with this limitation have been removed from the constraint set.
[63] PUO advises that having offers by individual facilities is being progressed as part of the WEM reforms.

Whilst voltage, transient and other network constraints related to the dynamic stability of the network have not been included as network constraint equations in modelling, EY has been advised of known fault level constraints at Kwinana discussed in Section 7.1.[64] EY has been informed that to date, Western Power has not yet identified any network limitations that set lower power transfer limits and that are likely to cause congestion above what would be determined by the thermal limits used in this study.

Existing generation runback schemes and special protection schemes that are currently operational on the SWIS have been taken into account by Western Power when formulating network constraint equations.

For each transmission constraint equation, Western Power also provides EY with summer and winter transmission line ratings to reflect the change in transmission line capacity due to ambient temperature conditions. In this context, summer is defined as November, December, January, February and March. Winter is defined as the other seven months.

Western Power provided network constraint equations based on the Base Scenario for the Partially Constrained case only and they do not reflect the impact of potential new entrant generation beyond 2022. The PUO has modified these equations to introduce terms on new entrant generator candidates in EY's modelling. It has also reformulated the network constraint equations to produce a second set suitable for the Fully Constrained Case. For both the Partially Constrained and Fully Constrained Cases it is assumed that any intermittent generator less than 10 MW will not be impacted by the constrained access reform (i.e., not subject to central dispatch). Some small generators are not reflected in the Western Power network constraint equations as their impact on transmission network power flows is considered immaterial.

In this Project, EY uses 2-4-C® to model least-cost dispatch in the WEM, with respect to all constraints, including the market price limits, network constraint equations and generator limits.

6.1.7 Treatment of intermittent loads

EY understands that proposed reforms to the WEM include consideration of how intermittent loads may impact the formulation of constraint equations. For this Project, it is understood that the intermittent load registration class will be retained across the Study Period.

These intermittent loads are typically larger industrial loads that may be serviced by a generator connected behind the same connection point. The generation behind the connection may also participate directly in the central dispatch process in the WEM, but with a dispatchable capacity (as opposed to a nameplate capacity) that takes into account the intermittent load.

This requires specific consideration in the formulation of network constraint equations as generator dispatch targets are based on a sent-out basis measured at the connection point. The intermittent load is therefore required to be taken into account when assessing constraints. This is modelled by representing the connection point with a generator and a constant load profile. Constraint equations are formulated to take the above into account.

[64] With one exception: an upper limit has been modelled for new entrant generation connected to the single 330 kV transmission line between Neerabup Terminal and Three Springs Terminal.

7. Modelling outcomes

7.1 Network constraint equation outcomes

During the course of the iterative modelling, selected candidate new entrant generator locations[65] were trialled for potential new entrant capacity. In many locations it was found that the network constraint equations bound frequently with a relatively small amount of additional new entrant capacity. In some areas, such as Albany, North Country and East Country, the modelling indicated limit of around 40 MW to 100 MW of wind or solar PV capacity that could be economically viable due to the level of network constraints binding, where the limit might be a little higher in the Fully Constrained Access Case depending on the capacity mix and demand in the rest of the market.

In addition to the network transmission limitations, Western Power advised the PUO and EY that the fault level at the Kwinana 132 kV bus exceeds its capability if more than 100 MW additional capacity[66] is connected at that location. An alternative Kwinana connection point is at 330 kV, where Western Power advised there is a 350 MW limit for similar reasons. New capacity at the 330 kV connection point is not limited by thermal transmission capacity from the network constraint equations modelled.

As a result of these limits, the final capacity mix forecast in each scenario and case (except the Unconstrained Access Case) was limited to the following locations and technologies:

- **Kwinana, Kemerton or Eastern Goldfields for OCGTs and CCGTs.** Two locations are considered at Kwinana, with the 132 kV location having a 100 MW limit and the 330 kV location having a 350 MW limit. In the High Scenario more capacity is required to meet the higher level of peak demand than is the case under the Base Scenario. In the High Scenario case, the PUO instructed EY to assume that Western Power builds the necessary equipment to allow sufficient capacity to connect at Kwinana.

- **Albany, Bunbury, East Country, Eastern Goldfields and North Country for wind and solar PV**, with the modelling outcomes driving capacity limits in each case as noted above.

For the above locations and technologies, EY forecasts that the network constraint equations will bind very infrequently for any scenario and case. In contrast, the PUO's capacity credit calculations are based on the peak demand period only and therefore the network constraint equations bind more frequently and have a material impact on capacity credit allocations in some cases. In particular, the capacity credit allocations in the Partially Constrained Access Cases tend to be reduced for new entrants in Kemerton, Eastern Goldfields, East Country and North Country. As a result of this and the Kwinana limits discussed above, less capacity is found to economically viable in the Partially Constrained Access Cases compared to the Fully Constrained Access Cases.

Despite the assumption that the Kwinana capacity limit is alleviated in the High Scenario, the applied network constraint equations are still forecast by the PUO to have a material impact on the allocated capacity credits for generators in some locations. As a result, a different commercially-driven new entrant capacity is forecast in the two cases across the Study Period.

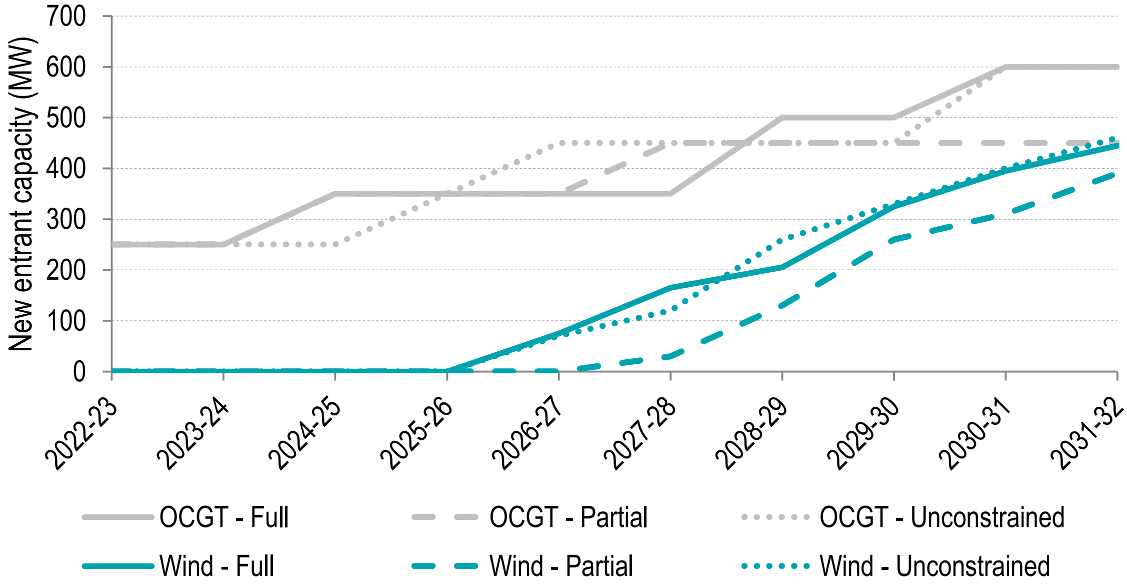
[65] The candidate new entrant locations were devised by the PUO, in consultation with EY, and were agreed on following the public consultation process in March 2018. The locations are presented in Section B.12.

[66] This assumes that new generation installed will have some fault level mitigation as part of its connection.

7.2 Capacity mix

Figure 13 presents the forecast new entrant large-scale[67] capacity mix over the Study Period in each case of the Base Scenario.

Figure 13: Forecast large-scale new entrant capacity by type in the WEM – Base Scenario, all cases



The only generation investments forecast, apart from the assumed uptake of rooftop PV are additional wind and OCGT capacity. Based on the assumptions used, including the OCGT costs and fuel prices, a new entrant 250 MW OCGT is forecast to be economically viable in the first year of the Study Period, 2022-23 in all cases. An OCGT is found to be more economically viable than other technologies in this year, resulting in wind not being forecast to be economically viable until after 2025-26 in all cases. Based on the cost assumptions used for existing generators, no commercially-driven retirements are forecast in the Base case in the Study Period.

As described in the previous section, the effect of network constraints on capacity credit allocations is the primary driver for the reduced new entrant capacity forecast in the Partially Constrained Access Case compared to the other two cases. In the Partially Constrained Access Case the maximum 450 MW of OCGT capacity is forecast to be installed at Kwinana, with no additional OCGT capacity found to be commercially viable because there are insufficient capacity credits capable of being allocated to new entrant generation capacity at Kemerton or other locations in the PUO's capacity calculations. In contrast, 250 MW is forecast to be installed at Kemerton in the Fully Constrained Access Case.

The new entrant wind capacity in the Fully Constrained Access Case comprises 70 MW at Albany, 40 MW at North Country and 335 MW in Eastern Goldfields at the end of the Study Period. In the Partially Constrained Access Case, no capacity credits are allocated to any new entrant wind capacity and this results is 55 MW less new entrant wind capacity forecast to be installed at the end of the Study Period compared the Fully Constrained Access Case, despite higher forecast market prices due to reduced OCGT capacity.

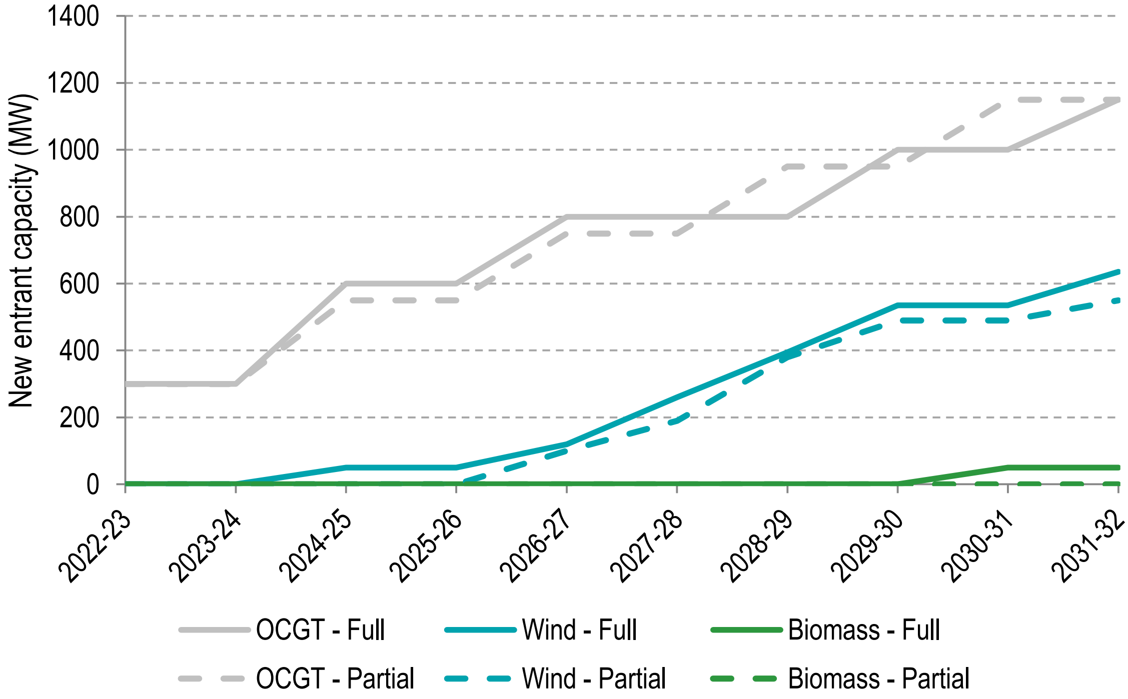
[67] Large-scale capacity mix omits rooftop PV uptake as this was an assumption rather than an outcome. The assumed new entrant rooftop PV is approximately 1,000 MW over the Study Period, as per the AEMO 2018 WEM ESOO Expected scenario used. This new entrant large-scale capacity also does not include the assumed wind and solar generators commissioned by 2022.

As shown in Figure 13, compared to the Fully Constrained Access Case, the forecast capacity mix in the Unconstrained Access Case has some variations in the timing of new OCGT and wind capacity. By the end of the Study Period, the total capacity of each technology is very similar. However, the locations for the new entrant capacity are different in the Unconstrained Access Case, as in the absence of network constraint equations the modelling found more economically competitive locations. The differences are:

- 350 MW of the 600 MW new entrant OCGT capacity is located at Neerabup instead of Kwinana, including the first 250 MW OCGT.
- 70 MW of the new entrant wind capacity is located at North Country, instead of 40 MW.

Figure 14 presents the forecast new entrant large-scale capacity mix over the Study Period in both cases for the High Scenario.

Figure 14: Forecast large-scale new entrant capacity by type in the WEM – High Scenario, both cases



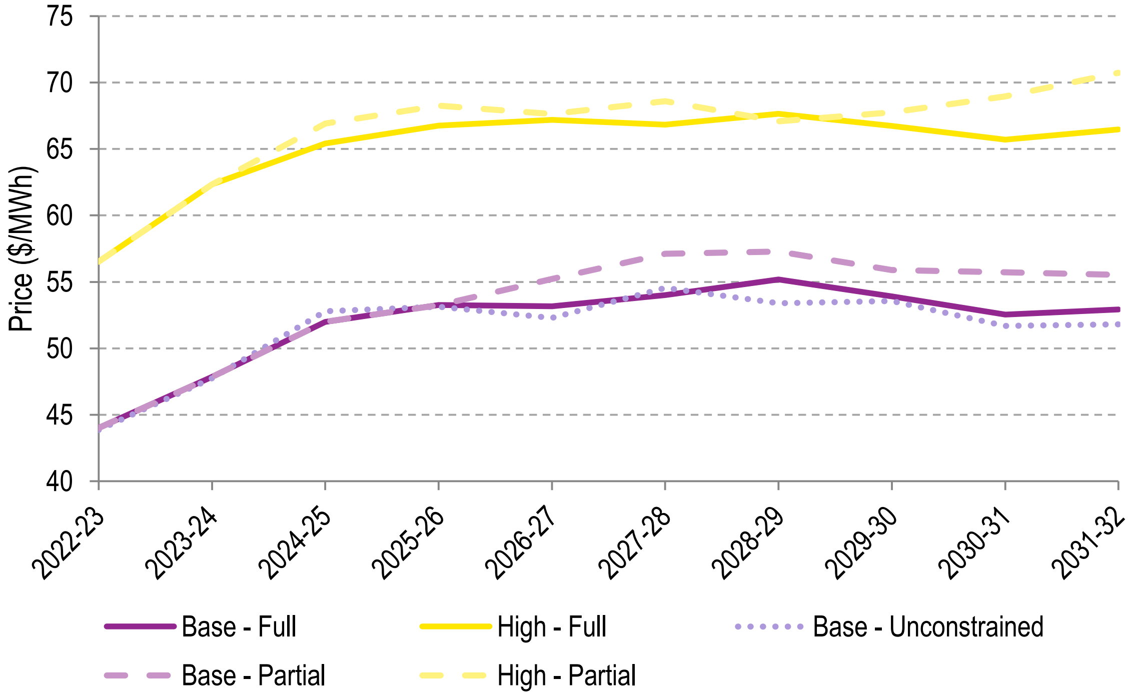
Due to the higher demand, the amount of new entrant capacity forecast in the High Scenario is higher than the Base Scenario for both OCGT and wind capacity. In the High Scenario, the modelling assumes that the fault level limitations at Kwinana are alleviated in both the Fully Constrained and Partially Constrained Access Cases to allow the installation of a larger quantity of OCGT to meet the higher demand outlook.

In addition, 50 MW of biomass capacity is forecast to be installed at Muja in the Fully Constrained Access Case. This biomass capacity is not forecast to enter in the Partially Constrained Access Case as the formulation of the network constraint equations in that case prevent the potential biomass generator located in Muja from receiving capacity credits. For the same reason, wind capacity is found to be viable in earlier years in the Fully Constrained Access Case, and by 2031-32 there is 85 MW of additional wind capacity forecast in that case. This additional wind capacity is mostly located in North Country.

7.3 Balancing market prices

Figure 15 shows the forecast annual average balancing market prices for each scenario and case.

Figure 15: Forecast annual average balancing market prices in each scenario and case*



* Note the y-axis is truncated for clarity

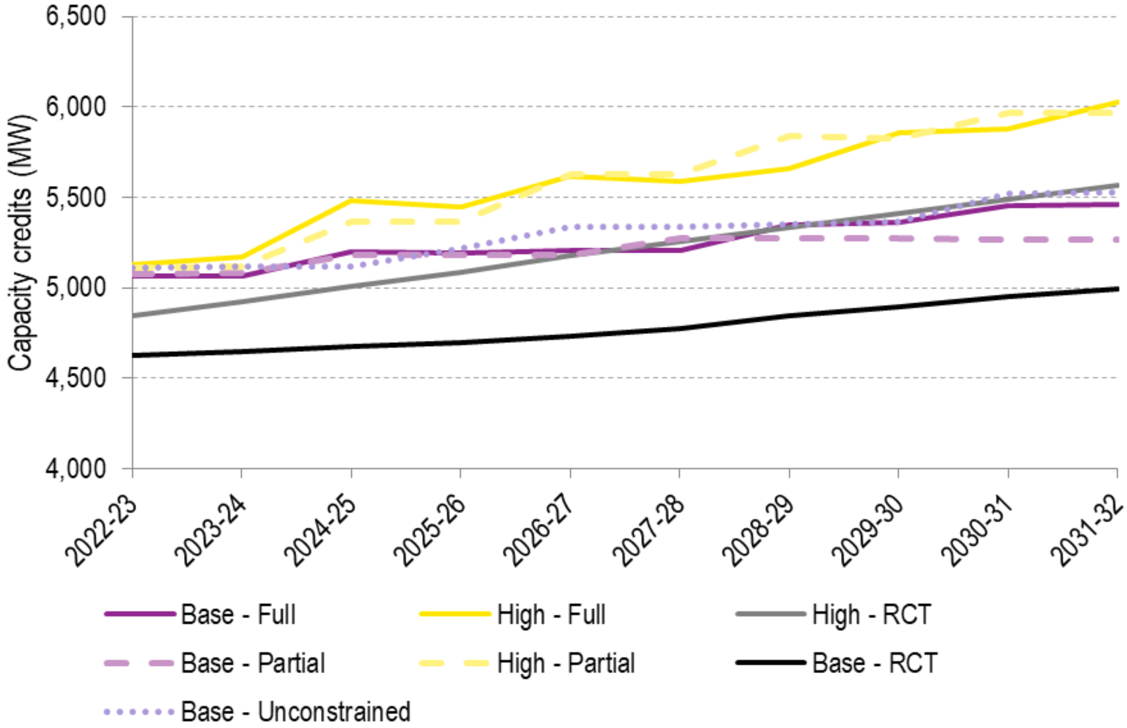
The High Scenario has higher balancing market prices than the Base Scenario at the start of and throughout the Study Period due to the higher demand outlook assumed for that scenario. The forecast balancing market prices have generally increasing trends across the Study Period. The forecast increase in the first three years of the Study Period is primarily due to the assumed increase in the gas price.

In each scenario the annual average balancing market prices are forecast to be lower in the Fully Constrained Access Case compared with the Partially Constrained Access Case. This is primarily driven by the merit order effect with the additional generator capacity installed in the Fully Constrained Case. In the Base Scenario the balancing market prices in the Unconstrained Access Case are forecast to be slightly lower than the Fully Constrained Access Case in some years due to the additional new entrant capacity forecast to be installed in the Unconstrained Access Case in those years.

7.4 Capacity market prices

After installing the commercially-driven new entrant capacity in each scenario and calculating the capacity credits, the total amount of capacity credits allocated is above the RCR in all cases and years. Figure 16 shows the forecast total capacity credits in the Base and High Scenarios compared with the reserve capacity target in those scenarios.

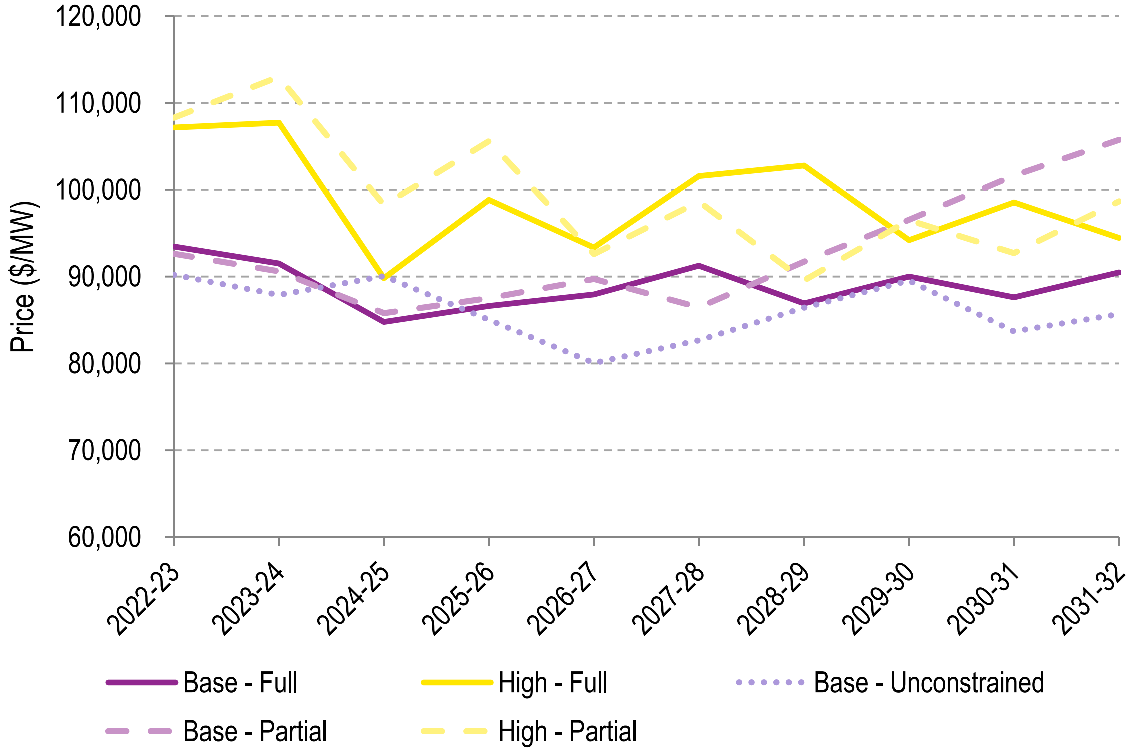
Figure 16: Total capacity credits versus the reserve capacity target in the Base and High Scenarios



In the High Scenario, a surplus of 200-300 MW above the RCR is initially forecast for 2022-23 and this grows to 400-500 MW by 2031-32, in both cases. Provided there is potential new entrant OCGT capacity with full capacity credit allocation, a new entrant OCGT typically is found to be economically viable with a surplus of 400-600 MW of capacity credits. In the Partially Constrained Access Cases, this condition is not the case with reduced capacity credits leading to less OCGT capacity being forecast to be installed. Figure 16 shows that the capacity surplus is smaller in the last few years of the Study Period in both Partially Constrained Access Cases shown. The consistent capacity credit surplus in the modelling results in no unserved energy being forecast in any scenario or case.

Figure 17 shows the resulting forecast capacity market prices in each scenario and case.

Figure 17: Forecast capacity market prices for each scenario and case*[68]



* Note the y-axis is truncated for clarity

The capacity market prices are forecast to be lower than the latest reserve capacity market price of $126,683/MW set by AEMO for 2019-20.[69] The primary driver of the forecast capacity market prices is the cost assumptions used for OCGTs in the modelling (as agreed by the PUO, in consultation with EY, following the public consultation in March 2018). If the assumed costs were higher, a new entrant OCGT would be modelled to require a higher revenue to be profitable, leading a higher capacity market price being forecast, which would correspond to a lower capacity credit surplus.

[68] The capacity market price is forecast using the formula in the WEM Market Rules and is based on a Benchmark Reserve Capacity Price (BCRP) of $139,154/MW. The BCRP is obtained from https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Benchmark-Reserve-Capacity-Price and has been reduced due to CPI conversion. If a higher BRCP were used, additional new entrant OCGT capacity would be forecast to be installed and the forecast capacity market price would be similar to the outcomes presented in this Report.

[69] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Benchmark-Reserve-Capacity-Price

To emphasise the impact of these OCGT costs assumptions, Table 9 compares the assumptions used by AEMO to calculate the BRCP and the AEMO ISP assumptions used in the wholesale market modelling.

Table 9: Comparing OCGT cost assumptions and their impact on the total fixed costs of an OCGT

OCGT parameter	AEMO 2018 ISP assumptions	AEMO assumptions for BRCP[70]
Capital cost ($/kW)	1,100 (approx.)	1,206
WACC (pre-tax real)	7.5%	5.29%
Financial lifetime (years)	30	15
Annualised capital cost ($/150 MW)	13,970,754 (approx.)	17,776,436
Annual fixed O&M ($/MW)	4,059	30,143
Capacity credit (MW)	148.5	148.5
Total annualised fixed costs - BRCP calculation ($/MW)	98,138	149,850

The table shows that if the AEMO ISP assumptions were used to calculate the BRCP, the BRCP would be just under $100,000/MW and 1.1 times this ($110,000/MW) would be maximum reserve capacity price. As stated in Section 5.2.4, the wholesale market modelling in this Project uses a BRCP of $139,154/MW but based on the AEMO ISP assumptions used in the modelling, an OCGT would only require a maximum of $98,138/MW from the capacity market to cover its fixed costs. One of the reasons the annual fixed cost assumption used by AEMO for the BRCP calculation is significantly higher than the AEMO 2018 ISP assumption is that the BRCP assumption includes more than just the FOM. $10,219/MW of the $30,143/MW is due to fixed network access and other ongoing charges, which is not included in the $4,059/MW AEMO 2018 ISP FOM assumption.

[70] Source: https://aemo.com.au/-/media/Files/Electricity/WEM/Reserve_Capacity_Mechanism/BRCP/2017/BRCP-calculation-spreadsheet-final-report-version.xlsx

7.5 Overall market cost impacts

The overall market cost impacts of Fully Constrained Access compared to the other cases was estimated from the market modelling outcomes focussing on two key cost impacts:

- **Total market payments:** this is the total amount paid to generators from the balancing market, LGC market and capacity market, and
- **Network investment:** this is the cost of investment in any transmission network augmentations required for the case modelled. Western Power provided the network cost estimates after determining the required augmentations, using the following approach:
  - In the Fully Constrained Access and Partially Constrained Access Cases: to alleviate any *violating*[71] network constraint equations in the Fully Constrained Access or Partially Constrained Access Cases, respectively. These augmentations are considered necessary to maintain power system security. The only augmentation found to be required is in the High Scenario, where the fault level limitation on the capacity installed at Kwinana was found to be a required upgrade in both cases to meet the reserve capacity target due to the high peak demand.
  - In the Unconstrained Access Case: to alleviate any *binding*[72] or *violating* constraint equations in an additional market simulation conducted by EY that uses the capacity mix forecast for the Unconstrained Access Case, but with the Fully Constrained Access constraint equations. For this exercise, we assumed that dispatch can only be conducted with unconstrained access to all generators if there are no binding network constraints. Around $700m in network investment was found to be required in the Base Scenario.

The Partially Constrained Access cases result in the highest total market payments and net system costs compared to the Fully Constrained Access cases in each scenario. Table 10 presents the outcomes for the Fully Constrained Access Case and, in the Base Scenario, the Unconstrained Access Case relative to the Partially Constrained Access Case in each scenario. These final numbers are different to the draft numbers presented in the PUO's constrained access report[73] dated 9 August 2018 for the Base Scenario due to refinements made to some aspects of the modelling, including incorporation of the aforementioned Kwinana Terminal capacity limit.

Table 10: Forecast overall market cost impacts by case, compared to the Partially Constrained Access Case

Scenario and case	Total market payments difference (10-year NPV)	Total market payments difference (60-year NPV)	Network costs difference	Net impact
Base - Unconstrained Access	-$0.3b	-$1.0b	+$0.7b	-$0.3b
Base - Fully Constrained	-$0.2b	-$0.8b	$0.0b	-$0.8b
High - Fully Constrained	-$0.15b	-$0.45b	$0.0b[74]	-$0.45b

[71] A network constraint equation violates in the market simulation when no solution can be found that satisfies the constraint. In the real world, this could result in overloading a transmission line and threaten power system security.

[72] A network constraint equation binds when it has an impact on dispatch and prevents dispatch occurring based on generation offers only in order to maintain system security.

[73] https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Consultation-Paper-Two-Improving-access-to-the-Western-Power-Network.pdf

[74] The cost for the network upgrade required in the High Scenario to allow more capacity at Kwinana is the same in both the Fully Constrained Access and Partially Constrained Access Cases, so the difference in network costs is $0b.

The total market payments is presented as a net present value over two time periods: the Study Period of 10 years and a 60-year period. The 60-year period allows a direct comparison between the total market payments and network costs between the Partially Constrained, Fully Constrained, and Unconstrained Access Cases as network investments are expected to have an economic life of 50 years. The 60-year NPV for the total market payments represents the net present value of the impact on the payments to 2080-81. This is based on an extrapolation of the ten years modelled by repeating the average of the final three years for every year post 2031-32. All the numbers are presented as a net present value and have been discounted[75] back to June 2018, as well as being presented in June 2018 dollars.

The forecast differences in the timing, quantity, and location of capacity mixes between the cases is the primary driver of differences in total market payments presented in Table 10. In the Base Scenario the total market payments is forecast to be $1 billion lower in the Unconstrained Access Case than in the Partially Constrained Access Case. However, providing continued unconstrained access to all generators is forecast by Western Power to require significant network augmentation in this scenario, with an estimated cost of $0.7 billion. Based on these two metrics, the Unconstrained Access Case is forecast to cost electricity consumers $0.3 billion less relative to the Partially Constrained Case.

In the Fully Constrained Access Case a net saving is forecast at $0.8b, which is entirely due to the forecast reduction in total market payments, as no additional network augmentations are forecast by Western Power to be required.

Due to the additional new entrant capacity forecast in the High Scenario's Fully Constrained Access and Partially Constrained Access cases, the Fully Constrained Access case is forecast to have $0.45b less total market payments.

7.6 Emissions

The forecast greenhouse gas emissions from producing electricity in the WEM tends to be less in the Fully Constrained Access cases compared to the Partially Constrained Access cases due to additional wind and biomass capacity installed.

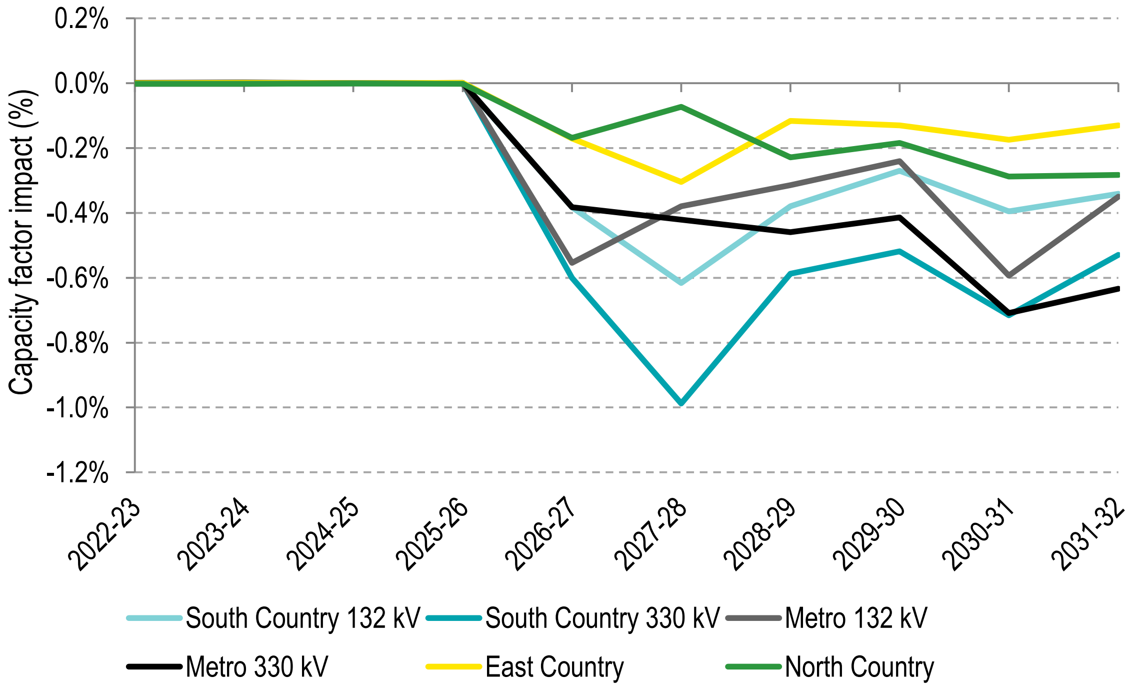
7.7 Impacts on generators

To preserve confidentiality and commercial sensitivity in the outcomes for individual generators, this section presents the impacts on existing generators aggregated by the region in which they are located. This section explores the impact of Fully Constrained Access on generators by presenting the difference between the Fully Constrained Access Case and the Partially Constrained Access Case.

[75] A pre-tax real discount rate of 7.5% was used, based on the public consultation process in March 2018.

Figure 18 presents the impact of Fully Constrained Access on the dispatched energy from existing generators, expressed as a difference in the forecast capacity factor[76] between the two cases.

Figure 18: Impact on aggregated existing generator dispatched energy (Full – Partial) – Base Scenario

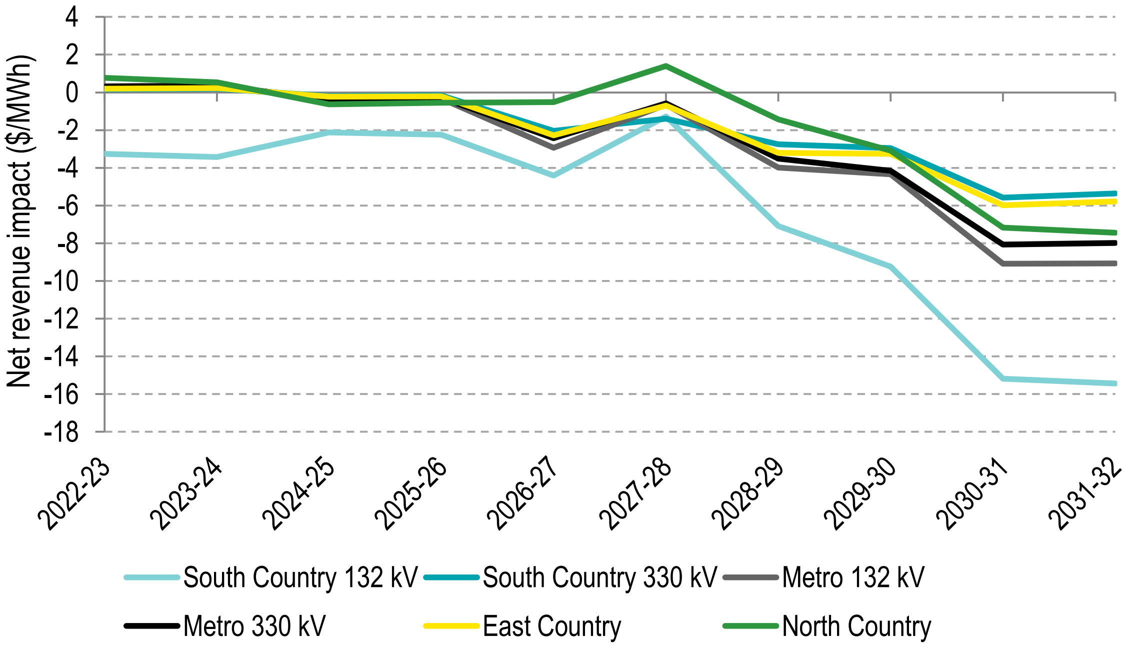


There is no difference in the dispatch of any generator in the first four years of the Study Period as the forecast capacity mix is the same in both cases (see Figure 13). For the subsequent six years, the dispatched energy of existing generators is lower in the Fully Constrained Access Case for all the regional aggregations presented due to the additional capacity forecast to be installed in that case. The maximum impact in any year is 1% for South Country 330 kV.

Figure 19 shows the forecast aggregated impact on the existing generators' net revenues in the Base Scenario, presented as a difference in net revenue in $/MWh sent-out.

[76] The capacity factor expresses the total energy dispatched from a generator, or group of generators, as a percentage of the maximum possible energy if the generators were dispatched at full output for the whole year.

Figure 19: Impact on aggregated existing generator net revenues (Full – Partial) – Base Scenario



The South Country 132 kV region is the most impacted by Fully Constrained Access overall in the Base Scenario. Despite the forecast capacity mix being identical in the first four years, the net revenue of generators in this region is forecast to be approximately $3/MWh less in the first two years and $2/MWh less in the following two. This is entirely driven by few capacity credits being allocated to generators in the South Country 132 kV region in the Fully Constrained Access Case. This is compounded with the impact of competition from additional new entrant capacity in the later years of the Study Period.

8. Conclusions

In the scenarios presented, the Fully Constrained Access Case results in the lowest overall costs of electricity supply for consumers, compared with the Partially Constrained Access Case. This is primarily a consequence of forecast lower balancing market prices and forecast lower capacity market prices on average across the Study Period due to more new entrant capacity being viable in the Fully Constrained Case.

The Fully Constrained Access Case is also forecast to have a lower cost than Unconstrained Access Case in the Base Scenario. This is primarily due to the forecast deferral of future network investment in the Fully Constrained Access Case compared with the Unconstrained Access Case.

The wholesale market modelling found very little binding of network constraints across the Study Period in any case and scenario modelled. The network constraints were found to bind more frequently during peak demand periods, impacting how capacity credits are allocated to existing and new entrant generators in both the Fully Constrained and the Partially Constrained Access Cases. This impact on capacity credits affects the commercial viability of new entrant generation capacity and is the primary driver of differences in the timing, location, and quantity of installed capacity mix between the cases modelled that, in turn, drives differences in wholesale market prices and total market payments.

The net revenues for existing generators is forecast to be lower in the Fully Constrained Access Case relative to the Partially Constrained Access Case in all scenarios. This is primarily a result of a combination of reduced capacity credits and being displaced in the merit order due to additional lower cost generation investment rather than being constrained off as a result of network constraints.

Based on the scenarios modelled, it can be concluded that in a Partially Constrained Access future it will be more difficult to meet the objectives of minimising costs and maintaining reliability in the WEM compared to Fully Constrained Access. This difficulty is more emphasised, the more new entrant capacity is needed or incentivised because the Partially Constrained Access environment presents fewer commercially viable opportunities for new entrant capacity.

Appendix A Benchmark outcomes

A.1 Introduction

As part of this Project, EY performed a benchmark of its half-hourly modelling of the WEM on the 2016-17 historical financial year. The objective of the benchmark is to devise suitable offer profiles for each generator to emulate their dispatch patterns in an historical year. These offer profiles are then used to create a market simulation model of the WEM that forecasts the future dispatch of existing generators under different scenarios. The outcomes of the benchmark were used in every scenario and case presented in this Report.

The benchmark was conducted using 2-4-C®; the same dispatch modelling software used for the forecasts. Whilst the forward-looking modelling involves conducting 100 simulations of each future year, taking into account different peak demands, forced outage profiles and weather patterns, the benchmark is conducted with a single half-hourly simulation of the historical year. This single simulation uses the actual demand, actual wind and solar generation and actual generators outages as they occurred (according to the data available).

Throughout a year in the actual market, generators experience changes in their operating parameters as well as fuel availability and price. However, data describing such changes is not available. The benchmarking task is used to approximate the typical operating and fuel parameters for each generator with up to four offer profiles, applying to different time periods.[77] Some generators are easier to model than others, where they exhibit more consistent dispatch levels relative to the balancing market price. The benchmarking outcomes demonstrate the ability for 2-4-C® to replicate the historical balancing price and generation outcomes with the data available. This, in turn, provides an understanding of some of the uncertainties in the forward-looking outcomes, facilitating a more informed interpretation of the forward-looking outcomes.

The benchmark was performed on the 2016-17 financial year since this was the most recent completed financial year at the time the study was conducted, and this would reflect the most up-to-date generator behaviour.

This appendix describes the input data used for the benchmarking study of 2016-17, and the approach taken along with the benchmarking outcomes.

[77] The time periods used for some generators are summer-peak, summer-off-peak, winter-peak and winter-off-peak.

A.1.1 Inputs summary

Table 11 summarises the input data and sources used in the benchmark.

Table 11: Summary of input data used for the benchmark

Input data	Source	How input data is used in benchmark simulation
Generator list	http://data.wa.aemo.com.au/#facility-scada	
2016-17 half-hourly demand	http://data.wa.aemo.com.au/#facility-scada	The half-hourly demand trace is the sum of the measured output of the modelled power stations. Generation is dispatched in merit to meet that historical demand in each trading interval.
2016-17 half-hourly generation	http://data.wa.aemo.com.au/#facility-scada Energy generated (MWh)/0.5. This data is the energy sent-out from the power station.	For large-scale wind and solar generators and units that are retired in the forward-looking modelling we set their available half-hourly generation at the historical levels rather than rely only offers for their dispatch. This is discussed further in Section A.1.2.
2016-17 STEM balancing market half-hourly prices	http://data.wa.aemo.com.au/#balancing-summary	Offer profiles for each generator were developed by analysing the relationship between half-hourly historical balancing prices and generation. Further detail on how we developed offer profiles is given in Section A.2.
2016-17 outages	http://data.wa.aemo.com.au/#outages	Historical reported outages (full and partial, planned, forced and consequential) were used directly as half-hourly availability profiles for each generator in the benchmark. This is described further in Section A.1.3.
2016-17 transmission loss factors	https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Loss-factors	Historical loss factors are used in 2-4-C® to adjust the offers before being used in dispatch as they are in the actual market.
2016-17 maximum price and alternative maximum price	https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits Two price limits were applied in the benchmark run for 2016-17, in line with the two price caps which apply in the WEM: - The Maximum Short Term Energy Market (STEM) Price which applies when non- liquid fuel is used by the highest cost peaking plant. For the 2016-17 benchmark year this was $240/MWh. - The Alternative Maximum STEM Price, which applies when liquid fuel is required to be used. For the 2016-17 benchmark year this was $347/MWh.[78]	The alternative maximum price is set as the maximum balancing market price that can be set in 2-4-C®. The maximum or alternative maximum were used as the highest bid band as appropriate for each generator.

[78] We note that the actual Alternative Maximum STEM Price is revised on a monthly basis.

A.1.2 Modelled generators

When determining which facilities to model in the benchmark and forward-looking simulations, we considered the set of facilities with SCADA data available (http://data.wa.aemo.com.au/#facility-scada) as we could only benchmark or model outcomes where there was historical dispatch available to replicate. We also cross-checked this set against the list of registered facilities (http://data.wa.aemo.com.au/#participants). The generators included in the benchmark and forward-looking simulations are listed in Table 12. The table also notes how we modelled the availability of each generator in the benchmark: using historical generation or offers only (with the total capacity as the availability less any reported outage).

- **Using historical generation**: We set some generators to be modelled with their historical half-hourly dispatch as their availability.
  - This applies to wind and solar PV generators due to their availability being highly dependent on their underlying resource; wind or solar insolation, respectively. Wind and solar PV generators tend to offer a static value between -$50/MWh and $0/MWh reflecting their short run marginal cost and external LGC revenue. Based on historical negative price outcomes in 2016-17, we offer all wind and solar PV generators at -$30/MWh.
  - It also applies to retiring thermal units as they are not modelled the forecast.[79]
- **Offers**: As mentioned earlier, a set of up to four offer profiles are used in 2-4-C® when creating a merit order to determine dispatch in each trading interval. Four offer profiles were used for some gas generators where their dispatch behaviour could be better represented by dividing the year into peak/off-peak periods and summer/winter seasons. These offer profiles are the ultimate output of the benchmark process for use in the forward-looking simulations.

Table 12: List of generators included in the benchmark

Generator	Availability profile
ALBANY_WF1	Historical generation
ALCOA_WGP	Capacity less reported outages
ALINTA_WWF	Historical generation
ALINTA_PNJ_U1	Capacity less reported outages
ALINTA_PNJ_U2	Capacity less reported outages
ALINTA_WGP_GT	Capacity less reported outages
ALINTA_WGP_U2	Capacity less reported outages
BW1_BLUEWATERS_G2	Capacity less reported outages
BW2_BLUEWATERS_G1	Capacity less reported outages
COCKBURN_CCG1	Capacity less reported outages
INVESTEC_COLLGAR_WF1	Historical generation
COLLIE_G1	Capacity less reported outages
EDWFMAN_WF1	Historical generation
GRASMERE_WF	Historical generation
GREENOUGH_RIVER_PV1	Historical generation
KEMERTON_GT11	Capacity less reported outages
KEMERTON_GT12	Capacity less reported outages
KWINANA_GT1	Historical generation
KWINANA_GT2	Capacity less reported outages
KWINANA_GT3	Capacity less reported outages
MUJA_G1	Historical generation
MUJA_G2	Historical generation
MUJA_G3	Historical generation
MUJA_G4	Historical generation
MUJA_G5	Capacity less reported outages
MUJA_G6	Capacity less reported outages
MUJA_G7	Capacity less reported outages

[79] The retiring units are KWINANA_GT1, MUJA_G1, MUJA_G2, MUJA_G3, MUJA_G4, MUNGARRA_GT1, MUNGARRA_GT2, MUNGARRA_GT3, WEST_KALGOORLIE_GT2, and WEST_KALGOORLIE_GT3, as listed in Table 17 in Appendix B.

Generator	Availability profile
MUJA_G8	Capacity less reported outages
MWF_MUMBIDA_WF1	Historical generation
MUNGARRA_GT1	Historical generation
MUNGARRA_GT2	Historical generation
MUNGARRA_GT3	Historical generation
NAMKKN_MERR_SG1	Capacity less reported outages
NEWGEN_KWINANA_CCG1	Capacity less reported outages
NEWGEN_NEERABUP_GT1	Capacity less reported outages
PERTHENERGY_KWINANA_GT1	Capacity less reported outages
PINJAR_GT1	Capacity less reported outages
PINJAR_GT10	Capacity less reported outages
PINJAR_GT11	Capacity less reported outages
PINJAR_GT2	Capacity less reported outages
PINJAR_GT3	Capacity less reported outages
PINJAR_GT4	Capacity less reported outages
PINJAR_GT5	Capacity less reported outages
PINJAR_GT7	Capacity less reported outages
PINJAR_GT9	Capacity less reported outages
PPP_KCP_EG1	Capacity less reported outages
PRK_AG	Capacity less reported outages
STHRNCRS_EG	Capacity less reported outages
TESLA_GERALDTON_G1	Capacity less reported outages
TESLA_KEMERTON_G1	Capacity less reported outages
TESLA_NORTHAM_G1	Capacity less reported outages
TESLA_PICTON_G1	Capacity less reported outages
TIWEST_COG1	Capacity less reported outages
WEST_KALGOORLIE_GT2	Historical generation
WEST_KALGOORLIE_GT3	Historical generation

Table 13 lists the generators not included in the benchmark or forward-looking simulations, due to their small size (i.e., 5 MW or less) and in some cases, lack of historical generation data. The half-hourly demand used in the benchmark is the sum of historical generation of the modelled generators only, as such no adjustment to demand was needed for to take into account the exclusion of these generators. However, twelve of the generators listed (as indicated) were included in the Base Scenario due to being included in AEMO's 2018 ESOO demand forecast.

Table 13: List of generators excluded in the benchmark

Generator	Annual energy (GWh)
ATLAS	3.3
BLAIRFOX_KARAKIN_WF1*	6.4
BLAIRFOX_WESTHILLS_WF3	2.9
BREMER_BAY_WF1*	1.5
DCWL_DENMARK_WF1*	5.1
GOSNELLS	0
HENDERSON_RENEWABLE_IG1*	13.4
KALBARRI_WF1*	4.0
RED_HILL*	25.7
ROCKINGHAM*	16.8
SKYFRM_MTBARKER_WF1*	5.8
SOUTH_CARDUP*	24.6
TAMALA_PARK*	38.8
BIOGAS01*	3.1
KALAMUNDA_SG*	0.004

* These units were included in the modelling of the Base Scenario, but modelled as unconstrained due to their small size and status as non-scheduled.

A.1.3 Outages

The outage data is modelled so that 2-4-C® excludes a generator from the merit order if it is on full outage and caps its output if it is on partial outage.

There are likely to have been network outages in 2016-17 that affect generation outcomes. We assume these are captured in the 'consequential' outages reported in the AEMO WA outage data and are therefore treated like other recorded outages.[80]

Any unrecorded outages will be reflected in the offer profiles of generators. Since we aim to reproduce the annual energy of each generator, unrecorded outages will be smeared out as generally lower generation over the whole year.

A.2 Benchmark simulation approach

As described in Section A.1, the objective of the benchmark is to tune the model to reproduce historical market outcomes using a set of up to four generator offer profiles for each generator. An offer profile can have up to ten price-quantity pairs. For example, an offer profile with two price-quantity pairs could be an offer of 100 MW at -$500/MWh and a further 50 MW at $30/MWh.

EY's approach to the benchmark can be summarised as follows:

- Set up 2-4-C® to simulate the 2016-17 financial year, using the input data as described earlier
- Establish an initial offer profile for each generator (using the procedure described below)
- Observe the pricing and dispatch outcomes and modify the offer profiles accordingly to achieve a closer match to the actual prices and dispatch in the market
- Iteratively re-simulate 2016-17 and refine the offer profiles until the price and generation outcomes are satisfactory.

Offer profile development

In the WEM, generators must offer at their expected SRMC or lower. The SRMC can change over time and depends on a generator's present level of generation, reflecting start-up costs, ramping capabilities, variable fuel costs and other time-varying external influences such as ambient temperature (typically, SRMC only accounts for fuel and variable O&M costs, and the inclusion of other factors is sometimes referred to as SRMC+). To allow for these variations in the SRMC and other factors, generators in the WEM can change their offers as frequently as from one trading interval to the next as well as offer capacity in multiple bid bands. Data on the mechanisms for these offer changes are largely confidential, and are difficult to predict in the future. As such, EY constructs offer profiles for 2-4-C® to represent the typical offer behaviour of different types of generators, as follows:

- **Baseload generators**: These are generators with a must-run component,[81] which operates regardless of the balancing price, followed by increasing quantities that operate as the balancing price increases. For these generators, any interval with zero generation is expected to be due to an outage.

[80] AEMO WA, *Outages*, Available at: http://data.wa.aemo.com.au/#outages. Accessed 12th December 2017.

[81] The must run component is generally equal to the minimum stable operation of the plant (below which the plant will experience technical problems, including a potential shut down). Units included in this category include ALINTA_PNJ_U1, ALINTA_PNJ_U2, BW1_BLUEWATERS_G2, BW2_BLUEWATERS_G1, COLLIE_G1, KWINANA_GT2, KWINANA_GT3, MUJA_G5, MUJA_G6, MUJA_G7, MUJA_G8, NEWGEN_KWINANA_CCG1, PPP_KCP_EG1, and TIWEST_COG1.

- **Thermal non-baseload generators**: For thermal generators without a must-run component, these may have intervals with zero generation where they have no capacity in merit. Their generation is offered in a price-responsive manner although it is acknowledged that non-price responsive operation may occur for several reasons including:
    - To fulfil verification and testing requirements imposed by AEMO to maintain Capacity Credits
    - To fulfil other maintenance and testing functions as part of routine asset management.
- **Liquid fuel generators**: For the liquid fuel generators, we generally offer all capacity at the alternative maximum price multiplied by the loss factor.[82]

Other important influences on generator offers in the WEM are the ancillary service markets: load following and spinning reserve. A generator participating in the load following ancillary services (LFAS) market typically offers into the balancing market at the market price floor for a certain level (base point) of its generation. It is then dispatched up or down from this base point with automatic generation control (AGC) every four seconds to meet fluctuations in the supply-demand balance, independent of the WEM balancing market pricing.

Insufficient information was available regarding historical dispatch of LFAS to account for its impact explicitly. Instead, offers were tuned to reflect historical generation outcomes (including LFAS). As a result, the offers inherently capture the operation of LFAS in 2016-17. Forecasting the future requirements of LFAS is beyond the scope of this Project. For simplicity, in the forward-looking modelling we modelled the following units with offers emulating participation in LFAS in all simulated trading intervals: NEWGEN_KWINANA_CCG1, KWINANA_GT2 and KWINANA_GT3.

A.3 Results

EY analysed the benchmarking outcomes for price and dispatch according to a few different metrics, such as annual averages, duration curves and time-of-day averages. These metrics demonstrate the ability of the model to replicate history and the adequacy of the model for forecasting the impacts of imposing network constraint equations.

The relevance of each metric is described in the following:

- **Annual average/total**: annual average price and generation and total annual generation provide the simplest overview of benchmarking outcomes, demonstrating the average accuracy of the modelling throughout the year. Achieving an accurate annual average price is important for determining the impact network constraint equations have on the price in the forecast. An accurately modelled total generation for a generator (along with the price) provides confidence that the forecast can determine the impact of network constraint equations on that generator's total generation and market revenues, where the latter also depends on the price outcomes.

- **Duration curves**: a duration curve on price or generation shows how accurately the model is producing the distribution of values. For example, the price duration curve can be used to highlight whether the number of negative prices at different levels is being accurately captured by the model, which is important to determine the behaviour of constraint equations during these trading intervals. An accurate price duration curve also indicates an accurate total merit-order stack (made up of the offer profiles from each generator) and this is important to model the impact constraint equations might have on price.

- **Duration curves of difference**: a duration curve on the difference between simulated and actual price or generation preserves the coincidence of outcomes. This gives an indication of the frequency at which the price/generation is benchmarked within a certain range of accuracy.

[82] Offers submitted apply at the generator transmission connection point. They are are subsequently divided by the loss factor when referred to the RRN during dispatch.

► **Time-of-day averages**: the price and dispatch of generators often exhibit a pattern in behaviour across the day, due to similar patterns in demand. For example, a generator may routinely operate at a minimum load overnight but produce more energy during the day. Capturing this daily behaviour accurately is another indicator that the modelling is producing outcomes that are in line with physical behaviour in the system.

The remainder of this section discusses these metrics for the modelling outcomes for overall balancing prices, and generation by station and region in the SWIS.

A.3.1 Price

The actual annual average price for 2016-17 is $56.0/MWh whereas the annual average price in the benchmark simulation is $55.7/MWh. With a difference of -$0.30/MWh (-0.5%), this is considered sufficiently accurate.

Figure 20 shows the balancing price duration curve for the benchmark compared with the actual balancing prices over the full extent of price outcomes. At this resolution, the benchmark looks to be highly accurate.

Figure 20: Price duration curve for 2016-17 and the benchmark, all prices

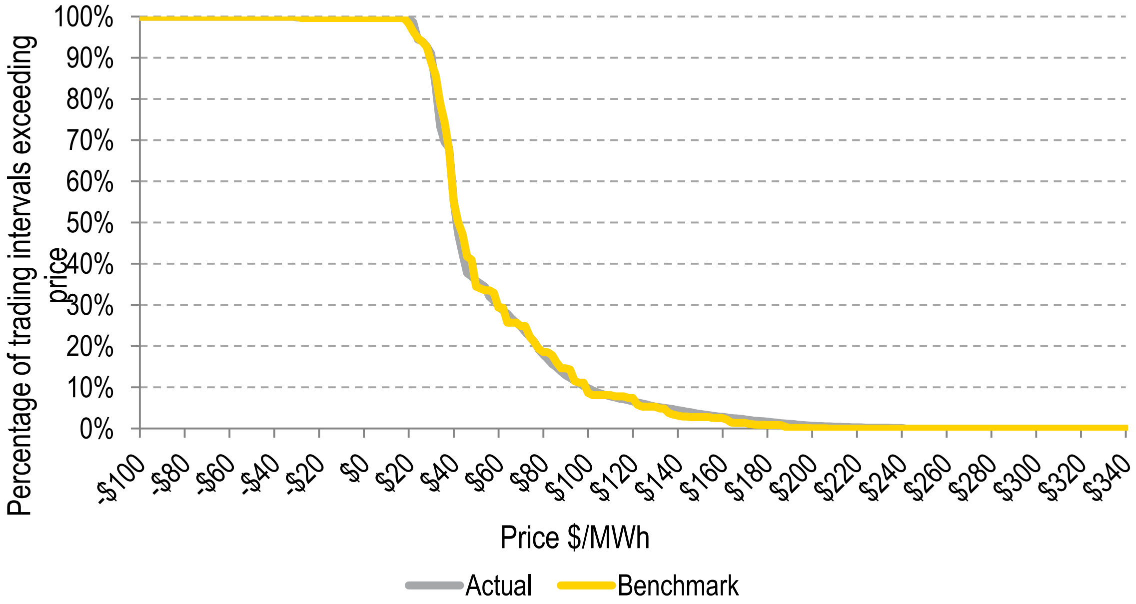


Figure 21 shows the duration curve for the difference between the benchmark and actual price outcomes in each trading interval. A perfect replication of 2016-17 would have a horizontal line at $0/MWh difference. The achieved result has a balancing price within ±$20/MWh in 81% of trading intervals and within ±$5/MWh in 43% of trading intervals. The difference is outside of ±$50/MWh in only 4% of trading intervals.

Figure 21: Price duration curve of the difference between the actual and the benchmark simulated balancing market prices

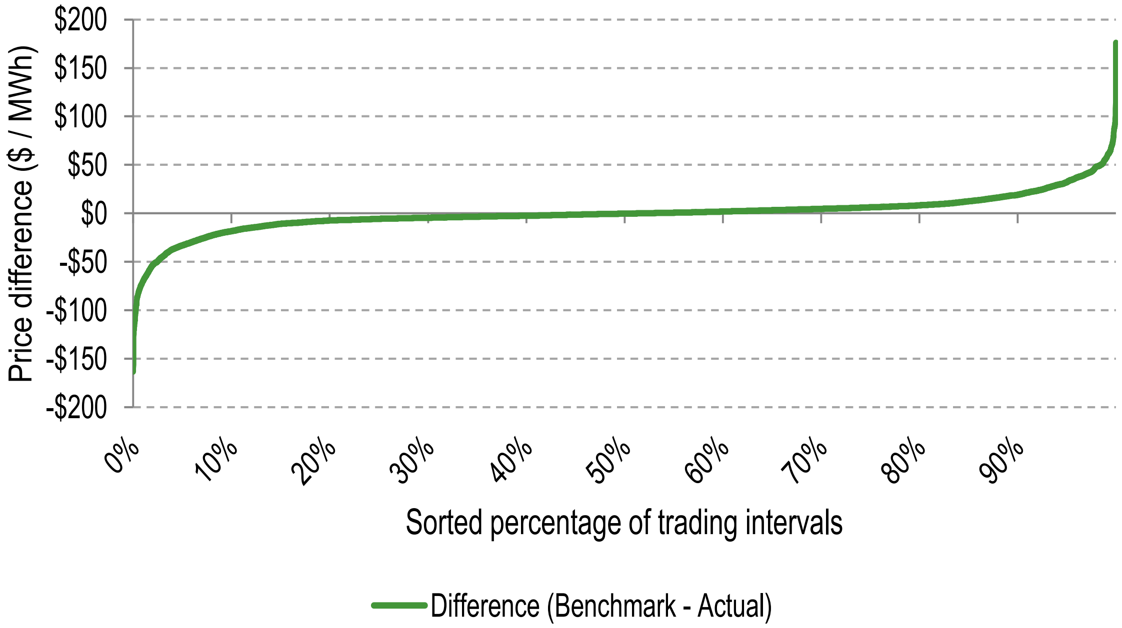
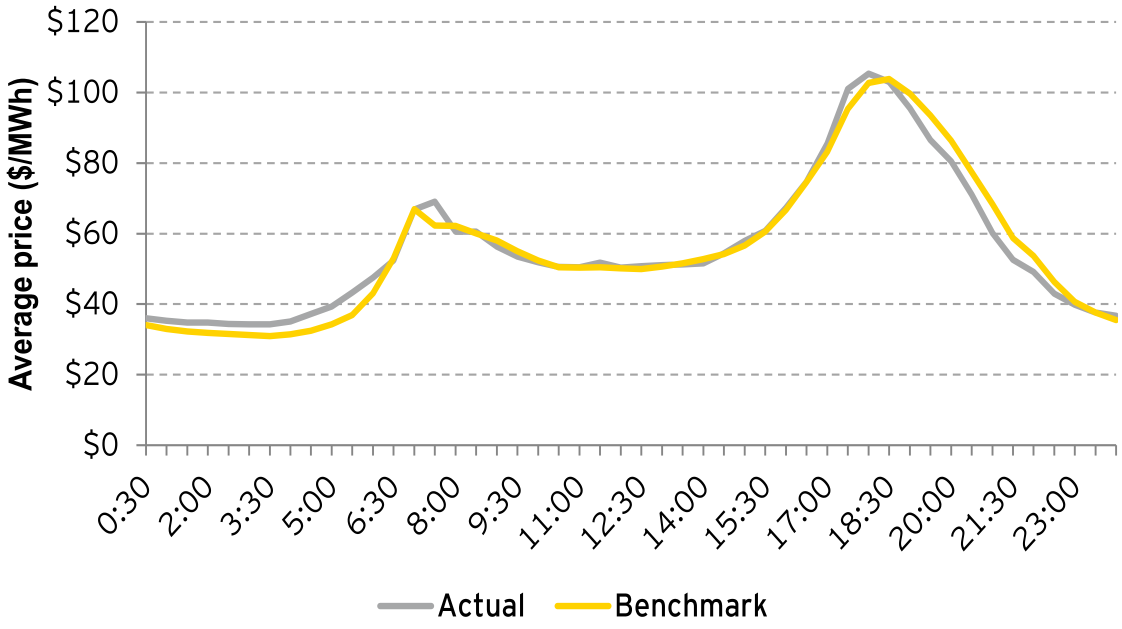


Figure 22 compares the benchmark to the actual prices on a time-of-day average basis. The general shape of the time-of-day average profile is modelled accurately, with the prices being lower overnight, broadly flat during the day following a morning peak, and with the overall peak across the day in the early evening. The average difference across the whole time-of-day profile is low, at around -$0.30/MWh (benchmark – actual). The benchmark prices are on average $4/MWh higher than actual from 19:00 to midnight, and on average $4/MWh lower from midnight to 06:00. During the day, between 08:00 and 16:00, the average difference is $0.10/MWh, and over the evening peak (16:00 to 20:00) the difference is around $1/MWh.

Figure 22: Annual average time-of-day prices comparing actual to the benchmark



The differences in price outcomes is due to the static offers being unable to capture daily offer and availability patterns of particular generators, such that the benchmark has too much generation available and offering low prices overnight, and not enough generation offering low prices during some of the peak periods. The implications of this outcome will be discussed in more detail in the following section on the results for generation.

A.3.2 Generation

A.1.3.1 Total generation by unit

The total generation and capacity factors in 2016-17 and the benchmark simulation are shown in Table 14. The list is sorted in order of descending historical annual energy.

Table 14: Total generation and capacity factor comparison (historical data sourced from the AEMO website, as listed in Table 11)

Rank	Unit_ID	Historical total generation (GWh)	Benchmark total generation (GWh)	Difference (Benchmark - Actual, GWh)	Percentage difference	Historical capacity factor	Benchmark capacity factor	Difference in capacity factor (percentage points)
1	NEWGEN_KWINANA_CCG1	2125.8	2127.0	1.2	0%	76%	76%	0.04%
2	COLLIE_G1	2046.5	2059.4	12.9	1%	73%	74%	0.46%
3	BW1_BLUEWATERS_G2	1666.6	1660.8	-5.9	0%	88%	87%	-0.31%
4	MUJA_G7	1141.6	1156.0	14.4	1%	62%	63%	0.78%
5	ALINTA_PNJ_U2	1123.2	1109.9	-13.3	-1%	88%	87%	-1.05%
6	ALINTA_PNJ_U1	1110.6	1110.3	-0.3	0%	87%	87%	-0.02%
7	MUJA_G8	1105.2	1119.1	14.0	1%	60%	61%	0.76%
8	MUJA_G5	1093.5	1097.1	3.6	0%	67%	68%	0.22%
9	MUJA_G6	1073.9	1076.9	3.0	0%	66%	66%	0.18%
10	BW2_BLUEWATERS_G1	758.7	764.9	6.2	1%	40%	40%	0.33%
11	INVESTEC_COLLGAR_WF1	664.2	664.2	0.0	0%	37%	37%	0.00%
12	PPP_KCP_EG1	545.2	548.8	3.6	1%	63%	63%	0.42%
13	KWINANA_GT2	393.4	378.7	-14.7	-4%	45%	43%	-1.68%
14	COCKBURN_CCG1	357.1	333.8	-23.3	-7%	17%	16%	-1.11%
15	ALINTA_WWF	339.1	339.1	0.0	0%	43%	43%	0.00%
16	KWINANA_GT3	272.0	272.0	0.0	0%	31%	31%	0.00%
17	EDWFMAN_WF1	250.4	250.3	-0.1	0%	36%	36%	-0.01%
18	PINJAR_GT10	239.8	255.6	15.9	7%	24%	25%	1.56%
19	MWF_MUMBIDA_WF1	202.5	202.5	0.0	0%	42%	42%	0.00%
20	TIWEST_COG1	185.6	173.8	-11.8	-6%	59%	55%	-3.73%
21	PINJAR_GT11	165.0	160.2	-4.8	-3%	15%	15%	-0.45%
22	NEWGEN_NEERABUP_GT1	164.9	145.9	-19.0	-12%	6%	5%	-0.66%
23	ALCOA_WGP	110.3	120.7	10.5	10%	50%	55%	4.78%
24	ALINTA_WGP_GT	98.5	103.4	4.8	5%	6%	7%	0.32%
25	MUJA_G4	91.5	91.5	0.0	0%	17%	17%	0.00%

Rank	Unit_ID	Historical total generation (GWh)	Benchmark total generation (GWh)	Difference (Benchmark - Actual, GWh)	Percentage difference	Historical capacity factor	Benchmark capacity factor	Difference in capacity factor (percentage points)
26	ALINTA_WGP_U2	88.8	93.4	4.6	5%	6%	6%	0.30%
27	STHRNCRS_EG	87.9	58.3	-29.6	-34%	22%	14%	-7.35%
28	PINJAR_GT9	71.9	76.3	4.4	6%	7%	8%	0.43%
29	MUJA_G3	62.3	62.2	-0.1	0%	12%	12%	-0.02%
30	MUJA_G1	61.9	61.9	0.0	0%	12%	12%	0.00%
31	KEMERTON_GT12	61.2	57.8	-3.4	-5%	5%	4%	-0.25%
32	PERTHENERGY_KWINANA_GT1	57.4	52.2	-5.2	-9%	6%	5%	-0.51%
33	MUJA_G2	54.7	54.7	0.0	0%	10%	10%	0.00%
34	ALBANY_WF1	51.0	51.0	0.0	0%	27%	27%	0.00%
35	KEMERTON_GT11	46.8	49.4	2.6	6%	3%	4%	0.19%
36	GRASMERE_WF1	37.0	37.0	0.0	0%	31%	31%	0.00%
37	GREENOUGH_RIVER_PV1	22.5	22.5	0.0	0%	26%	26%	-0.03%
38	PINJAR_GT7	7.2	7.8	0.6	8%	2%	2%	0.18%
39	PINJAR_GT2	6.9	8.2	1.3	19%	2%	3%	0.40%
40	PINJAR_GT5	6.8	7.9	1.0	15%	2%	2%	0.31%
41	MUNGARRA_GT1	6.5	6.5	0.0	0%	2%	2%	0.00%
42	MUNGARRA_GT2	4.4	4.4	0.0	0%	1%	1%	0.00%
43	PINJAR_GT4	3.3	0.1	-3.2	-97%	1%	0%	-0.95%
44	PINJAR_GT3	2.1	0.1	-2.0	-93%	1%	0%	-0.58%
45	PINJAR_GT1	2.0	0.0	-2.0	-100%	1%	0%	-0.62%
46	MUNGARRA_GT3	1.6	1.6	0.0	0%	0%	0%	0.00%
47	NAMKKN_MERR_SG1	0.4	0.0	-0.4	-100%	0%	0%	-0.06%
48	PRK_AG	0.2	0.0	-0.2	-100%	0%	0%	-0.04%
49	WEST_KALGOORLIE_GT2	0.2	0.2	0.0	0%	0%	0%	0.00%
50	WEST_KALGOORLIE_GT3	0.1	0.1	0.0	0%	0%	0%	0.00%

Rank	Unit_ID	Historical total generation (GWh)	Benchmark total generation (GWh)	Difference (Benchmark - Actual, GWh)	Percentage difference	Historical capacity factor	Benchmark capacity factor	Difference in capacity factor (percentage points)
51	TESLA_GERALDTON_G1	0.1	0.0	-0.1	-100%	0%	0%	-0.12%
52	TESLA_NORTHAM_G1	0.1	0.0	-0.1	-100%	0%	0%	-0.12%
53	KWINANA_GT1	0.1	0.1	0.0	0%	0%	0%	0.00%
54	TESLA_PICTON_G1	0.0	0.0	0.0	-100%	0%	0%	-0.04%
55	TESLA_KEMERTON_G1	0.0	0.0	0.0	-100%	0%	0%	-0.04%

A.1.3.2 Duration curves and time-of-day averages by super-station

This section presents generation duration curves and time-of-day averages by super-station, as defined in Table 15, for the units for which benchmark offers were developed. In most instances, super stations represent individual power stations. The exception is liquid fuel generators. Super stations provide a means to show how the model performed on a power station, or higher level basis, where individual units may be difficult to model accurately due to being operated within the Synergy portfolio or having a very low capacity factor. Liquid fuel has been aggregated as these generators ran infrequently in 2016-17 and often in a non-price responsive manner. For example, the intervals in which the greatest generation was achieved by liquid fuel generators occurred at clearing prices far below the Alternative Maximum STEM Price, and in most cases, below even average balancing prices across the year.

Table 15: Super-stations and their operation type

Super-station	Units	Operation type
Alinta Pinjarra, Unit 1	ALINTA_PNJ_U1	Baseload
Alinta Pinjarra, Unit 2	ALINTA_PNJ_U2	Baseload
Alinta Wagerup	ALINTA_WGP_GT, ALINTA_WGP_U2	Thermal non-baseload
Alcoa Wagerup Cogen	ALCOA_WGP	Cogen special
Bluewaters	BW2_BLUEWATERS_G1, BW1_BLUEWATERS_G2	Baseload
Cockburn	COCKBURN_CCG1	Thermal non-baseload
Collie	COLLIE_G1	Baseload
Kemerton	KEMERTON_GT11, KEMERTON_GT12	Thermal non-baseload
Kwinana Power Partners	PPP_KCP_EG1	Baseload
Kwinana Swift OCGT	PERTHENERGY_KWINANA_GT1	Peaker
Liquid	NAMKKN_MERR_SG1, PRK_AG, STHRNCRS_EG, TESLA_GERALDTON_G1, TESLA_KEMERTON_G1 TESLA_NORTHAM_G1, TESLA_PICTON_G1,	Peaker
Muja C	MUJA_G5, MUJA_G6	Baseload
Muja D	MUJA_G7, MUJA_G8	Baseload
Newgen Kwinana CCGT	NEWGEN_KWINANA_CCG1	Baseload
Newgen Neerabup OCGT	NEWGEN_NEERABUP_GT1	Thermal non-baseload
Pinjar	PINJAR_GT1, PINJAR_GT2, PINJAR_GT3, PINJAR_GT4, PINJAR_GT5, PINJAR_GT7, PINJAR_GT9, PINJAR_GT10, PINJAR_GT11	Thermal non-baseload
Tiwest Cogen	TIWEST_COG1	Baseload
Verve Kwinana	KWINANA_GT2	Baseload

Table 15 also shows the super stations are allocated into four operation types:

- **Baseload**, which have very high start-up costs and effectively generate with a must-run component. All the cogeneration units also fall under this category as they have an observed must-run component (with the exception of Alcoa Wagerup).
- **Thermal non-baseload**
- **Peaker**, which have a very high SRMC and operate rarely
- **Cogen special**, containing one cogen generator that operates under variable SRMC states[83]

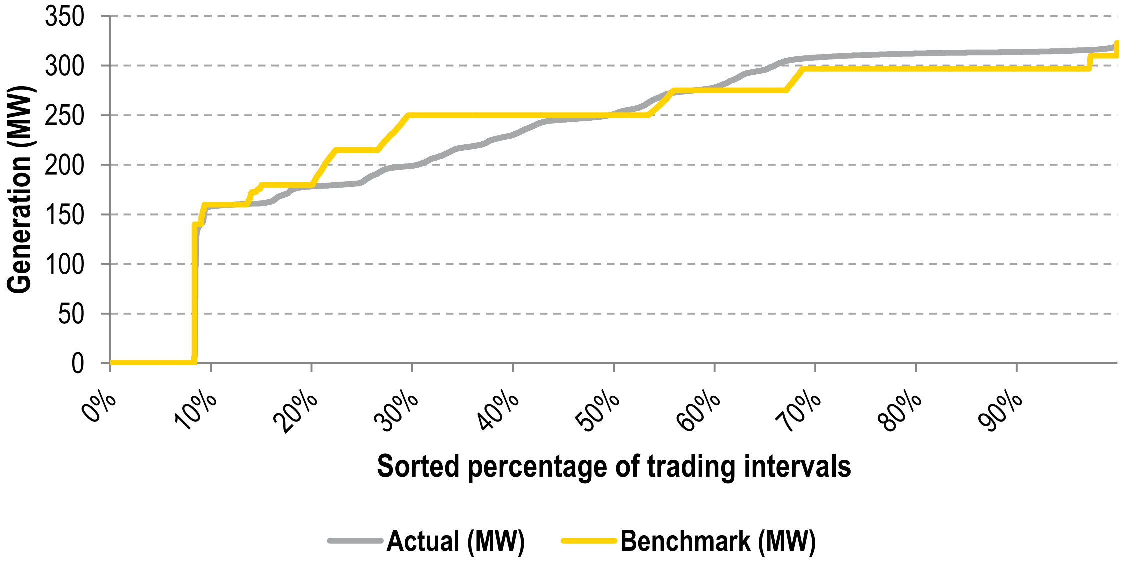
[83] The other cogen super stations operate in a more consistent baseload fashion and are allocated to the baseload category.

The duration curve and time-of-day average results are shown for selected representative super stations for baseload, thermal non-baseload, peaker, and cogeneration operation types in the following sections.

Collie power station, representing baseload generators

Figure 23 compares the actual and benchmark generation for Collie power station using the duration curve over all trading intervals in the year. The generation duration outcomes for Collie are broadly representative of all other baseload superstations listed in Table 15.

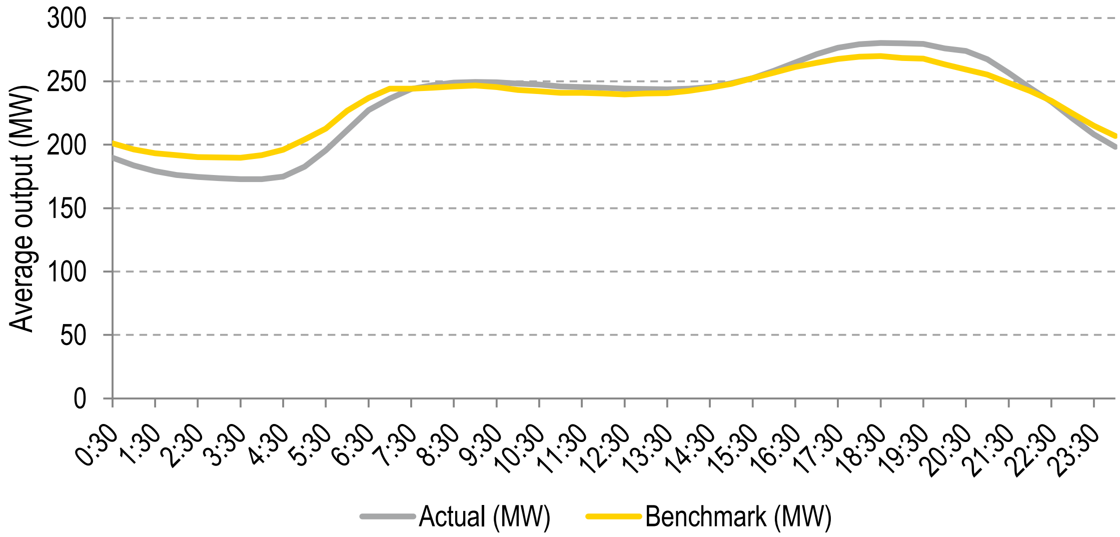
Figure 23: Generation duration curves for Collie comparing actual to the benchmark



The duration curve is zero for approximately 8% of the trading intervals in the year, representing that Collie was on full outage for that proportion of time in 2016-17. The first positive values are around 140 MW or higher, representing the minimum load (must-run) for Collie's operation. From this point, the duration curve has a smoother slope for the actual 2016-17 data than the benchmark demonstrating that Collie has a larger range of generation set-points than is captured by the price-quantity pairs used for Collie the benchmark. The smoother generation duration curve for actual 2016-17 data is a general result for all generators changing their offer profiles changing throughout the year. EY considers this to be an expected and acceptable result for the benchmark.

Figure 24 shows the annual average time-of-day generation for Collie, highlighting that on average, the benchmark has more generation overnight and slightly less generation in the evening, though overall follows a similar pattern of generation over the course of the day.

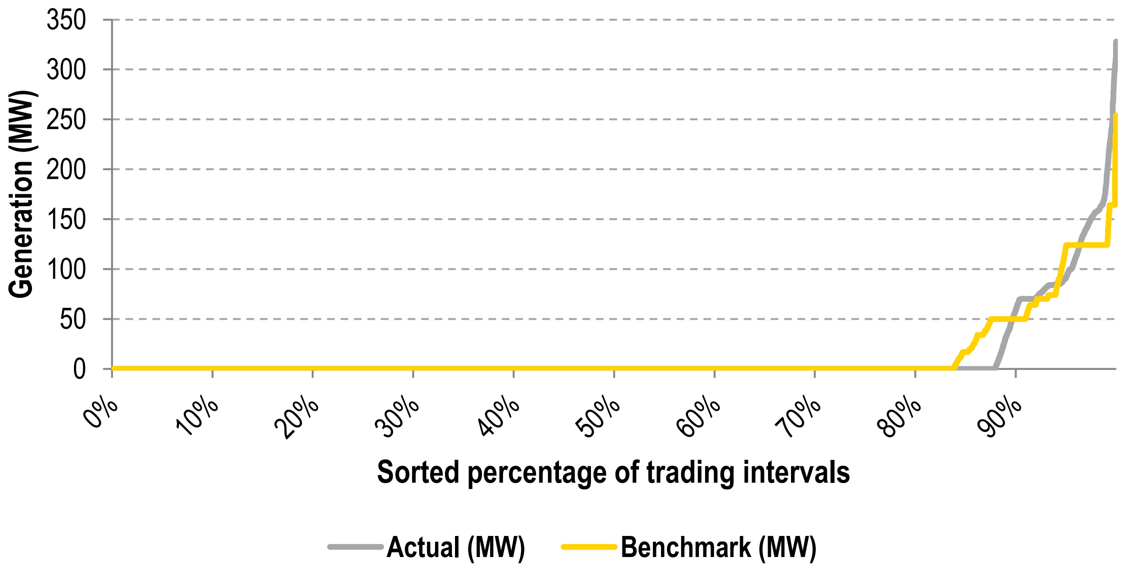
Figure 24: Annual average time-of-day generation for Collie comparing actual and the benchmark



Kemerton, representing thermal non-baseload generators

Kemerton is one of the generators in the WEM that is fuelled by natural gas with open-cycle technology. Figure 25 compares the actual and benchmark generation for Kemerton power station using the duration curve over all trading intervals in the year.

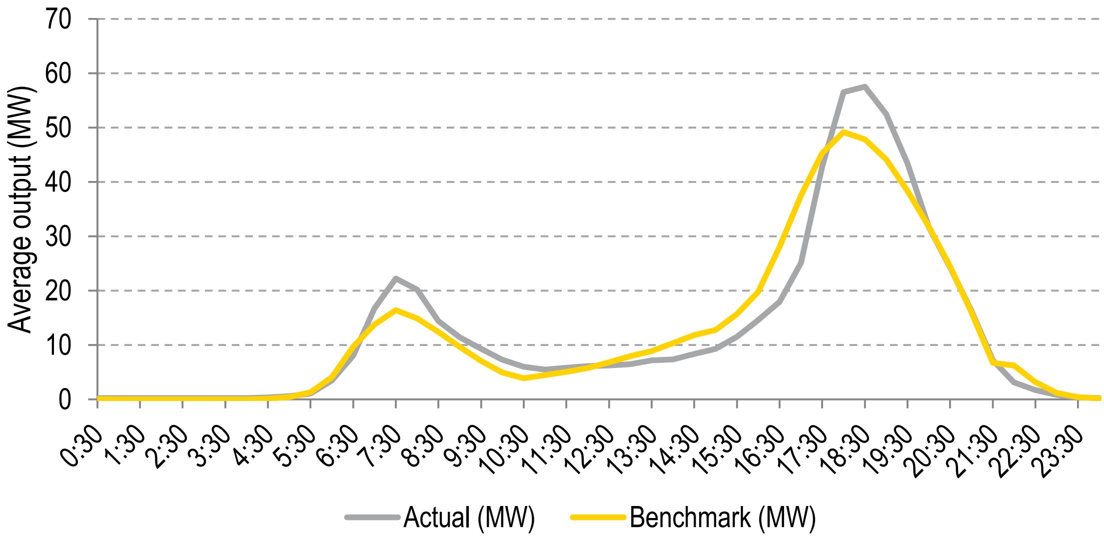
Figure 25: Generation duration curves for Kemerton comparing actual and the benchmark



The actual generation duration curve shows that when Kemerton generates it is usually at around 60 MW or above. In the benchmark, there are slightly more trading intervals with generation below 60 MW and fewer trading intervals with generation above 60MW, with overall total generation 1% lower than actual. While the benchmark does not achieve the level of maximum generation over the year, these stations operate at or near their maximum for so few intervals in the year that it is difficult to target these specific intervals without resulting in significant over-generation over the

rest of the year.[84] EY considers this to be an acceptable result for the benchmark.
Figure 26 shows that the modelled annual average time-of-day generation generally follows a similar pattern to the historical trend.

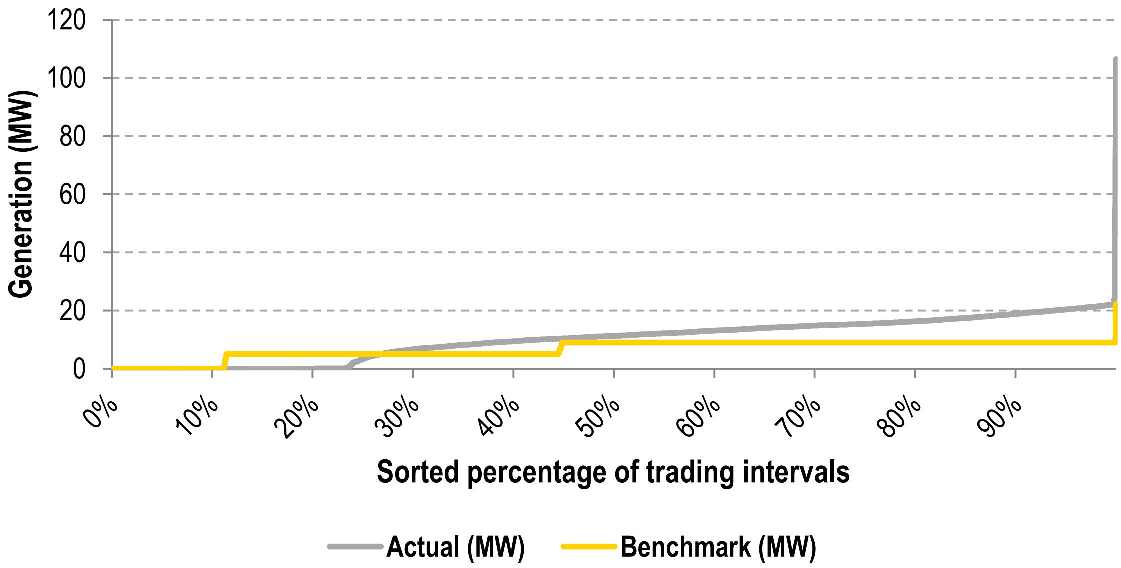
Figure 26: Annual average time-of-day generation for Kemerton comparing actual and the benchmark



Liquid super-station, representing peakers

Figure 27 compares the actual and benchmark generation for the liquid super-station using the duration curve over all trading intervals in the year.

Figure 27: Generation duration curves for liquid super-station in 2016-17 and the benchmark



There is a difference between the maximum generation achieved in the benchmark compared to actual. However, the intervals where actual generation is above 100 MW all occurred at prices of only around $32/MWh and as such occurred due to reasons other than price. EY considers such differences to have an immaterial impact on the constrained access outcomes in this Project, as these dispatch differences occur infrequently.

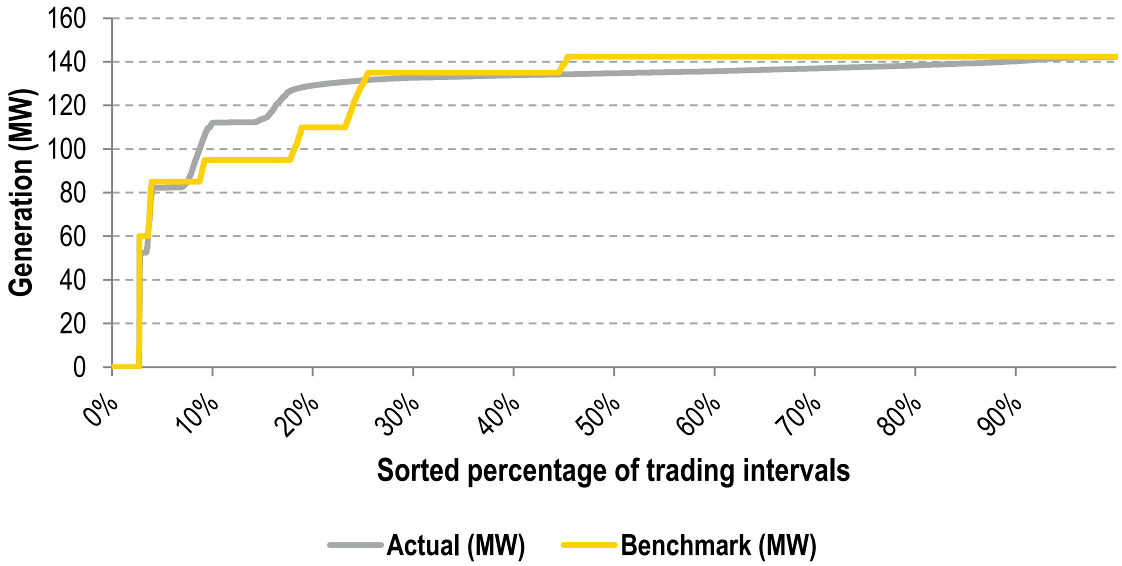
[84] For example, Kemerton was found to generate within 30% of its maximum historical generation in only 2% of intervals over the 2016-17 year.

Alinta Pinjarra, Unit 1 representing cogeneration

With the exception of Alcoa Wagerup Cogen, cogeneration units (ALINTA_PNJ_U1, ALINTA_PNJ_U2, PPP_KCP_EG1, and TIWEST_COG1) operate with a must-run component and are therefore grouped with other thermal baseload generators. This section presents the results for cogenerators as a sub-set of the thermal baseload generators which have a must-run component but operate with fuel other than coal.[85]

Figure 28 compares the actual and benchmark generation for Alinta Pinjarra Unit 1 using the duration curve over all trading intervals in the year. Whilst benchmark achieves the same total generation over the year as Alinta Pinjarra Unit 1 achieved in 2016-17, the chart indicates this comprises a lower number of intervals at lower levels of generation, and a higher number of intervals at higher levels of generation.

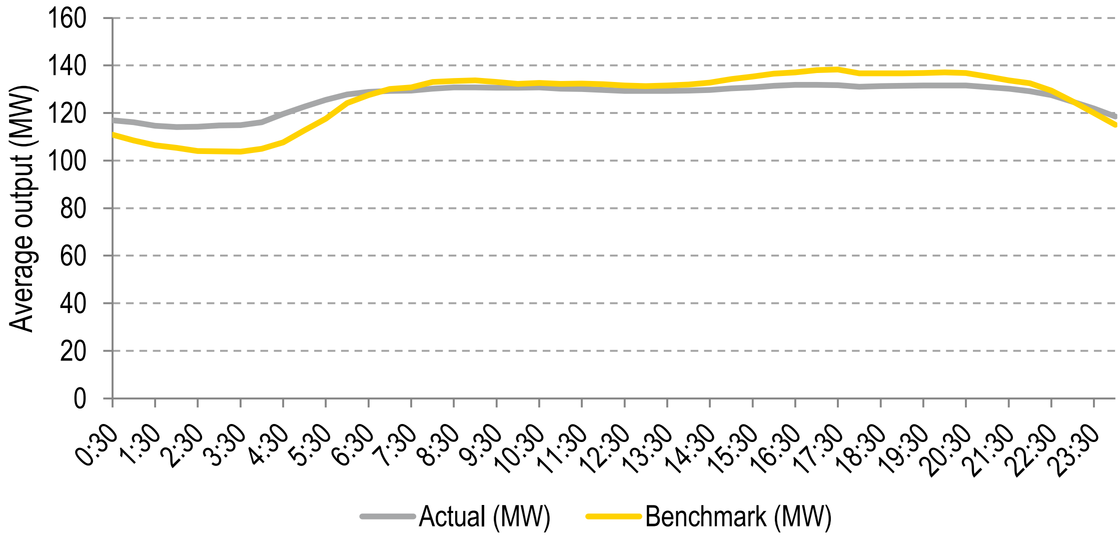
Figure 28: Generation duration curves for Alinta Pinjarra Unit 1 comparing actual and the benchmark



[85] The operation of Alcoa Wagerup Cogen is much more variable and at times not price-responsive because part of its driver to operate is not market driven. There is limited information publically available on the operating strategy and it generated 110 GWh in 2016-17 which equates to 0.6% of all annual energy modelled. As a result, we followed the same offer profile development approach as for the other generators but focussed on achieving an acceptable level of annual energy. Overall, the benchmark achieved an annual energy of 121 GWh, representing a 5% higher capacity factor (in percentage points) than occurred in 2016-17.

Figure 29 shows that in terms of the annual average time-of-day generation, the benchmark follows a broadly similar pattern over the course of the day, with slightly more generation in the evening before midnight, and slightly less thereafter, until around 06:30.

Figure 29: Annual average time-of-day generation for Alinta Pinjarra Unit 1in 2016-17 and the benchmark



A.1.3.3 Duration curves and time-of-day averages, aggregated by region

As mentioned in the body of this Report, the constraint equations used in this study describe thermal limits on transmission lines. Ultimately transmission line flows are heavily dependent on concurrent generation in different areas of the transmission grid. Alignment between historical and benchmark outcomes at a regional aggregate level is an indicator of the model's ability to estimate transmission line flows across major transmission corridors than individual stations or super stations.

In order to demonstrate how well the model replicates historical transmission line flows, we present regional aggregations from 2016-17 and the benchmark in this section. The sum of half-hourly generation time-series was calculated for each regional aggregate presented in Table 16, and duration and time-of-day averages computed for each aggregate.

The regional aggregations were developed based on the generation centres connected by major transmission corridors in the SWIS. While Table 16 details the units that are situated in each region, the results presented in the charts below only include units for which benchmark offers were developed (so that the units where historical availability was modelled do not skew the presentation of the benchmark results as compared to historical outcomes).

Table 16: Regional aggregation of units

Region	Units included in analysis (benchmark offers developed and modelled)	Historical total generation (GWh)	Benchmark total generation (GWh)	Difference (Benchmark – Actual, GWh)	Units excluded (historical availability modelled)
East Country	NAMKKN_MERR_SG1, PRK_AG, STHRNCRS_EG, TESLA_NORTHAM_G1,	89	58	-30	WEST_KALGOORLIE_GT2, WEST_KALGOORLIE_GT3, INVESTEC_COLLGAR_WF1
Metro 132 kV	COCKBURN_CCG1, KWINANA_GT3, PERTHENERGY_KWINANA_GT1, PPP_KCP_EG1	1,353	1,313	-40	KWINANA_GT1, KWINANA_GT2,
Metro 330 kV	NEWGEN_KWINANA_CCG1, NEWGEN_NEERABUP_GT1	2,291	2,273	-18	
North Country	PINJAR_GT1, PINJAR_GT10, PINJAR_GT11, PINJAR_GT2, PINJAR_GT3, PINJAR_GT4, PINJAR_GT5, PINJAR_GT7, PINJAR_GT9, TESLA_GERALDTON_G1	505	516	11	MUNGARRA_GT1, MUNGARRA_GT2, MUNGARRA_GT3, , ALINTA_WWF, EDWFMAN_WF1, GREENOUGH_RIVER_PV1, MWF_MUMBIDA_WF1
South Country 132 kV	ALCOA_WGP, ALINTA_PNJ_U1, ALINTA_WGP_GT, ALINTA_WGP_U2, TESLA_KEMERTON_G1, TESLA_PICTON_G1, TIWEST_COG1,	1,594	1,602	8	MUJA_G1, MUJA_G2, MUJA_G3, MUJA_G4, ALBANY_WF1, GRASMERE_WF1

Region	Units included in analysis (benchmark offers developed and modelled)	Historical total generation (GWh)	Benchmark total generation (GWh)	Difference (Benchmark - Actual, GWh)	Units excluded (historical availability modelled)
South Country 330 kV	ALINTA_PNJ_U2, BW1_BLUEWATERS_G2, BW2_BLUEWATERS_G1, COLLIE_G1, KEMERTON_GT11, KEMERTON_GT12, MUJA_G5, MUJA_G6, MUJA_G7, MUJA_G8	10,117	10,151	34	

East Country

Figure 30 shows the actual and benchmark generation for the East Country aggregation using the duration curve over all trading intervals in the year. As set out in Table 16, the only units included in the comparison between the benchmark and actual outcomes are those in the liquid category, therefore the results for East Country are consistent with those for the liquid super-station shown above.

Figure 30: Generation duration curves for East Country in 2016-17 and the benchmark

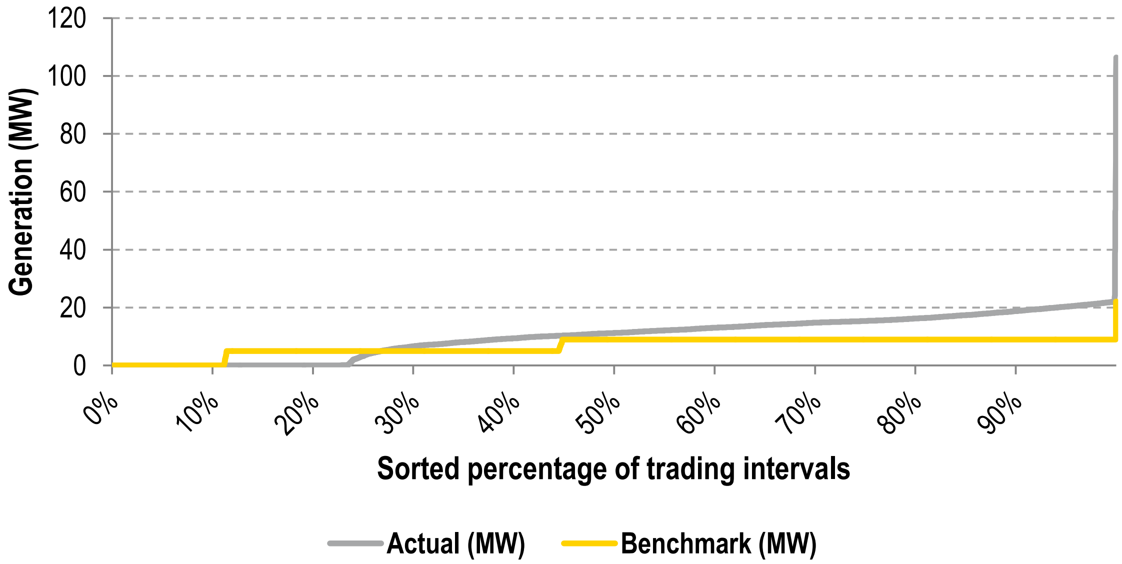
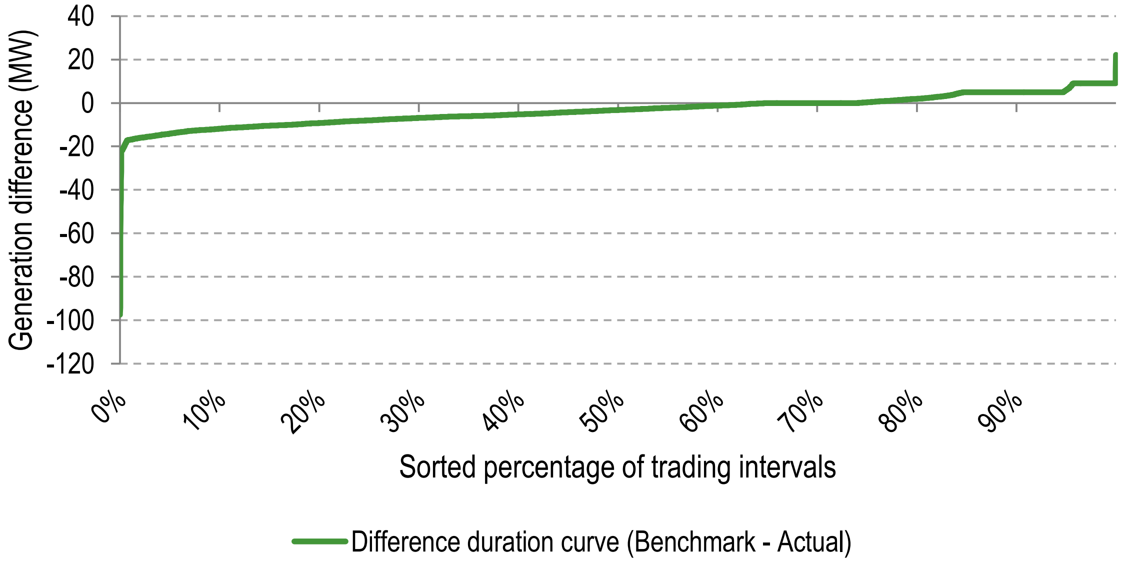


Figure 31 shows the duration curve for the difference between the benchmark and actual generation in each trading interval. In almost 100% of trading intervals, the benchmark outcomes are within ±20 MW of the historic outcomes in 2016-17. The maximum possible difference is ±106 MW.

Figure 31: Generation duration curve of the difference comparing actual and the benchmark simulation for East Country



Metro 132 kV

Figure 32 compares the actual and benchmark generation for the Metro 132 kV aggregation using the duration curve over all trading intervals in the year. Overall, generation in this region is just 3% lower in the benchmark than actual.

Figure 32: Generation duration curves for Metro 132 kV comparing actual and the benchmark

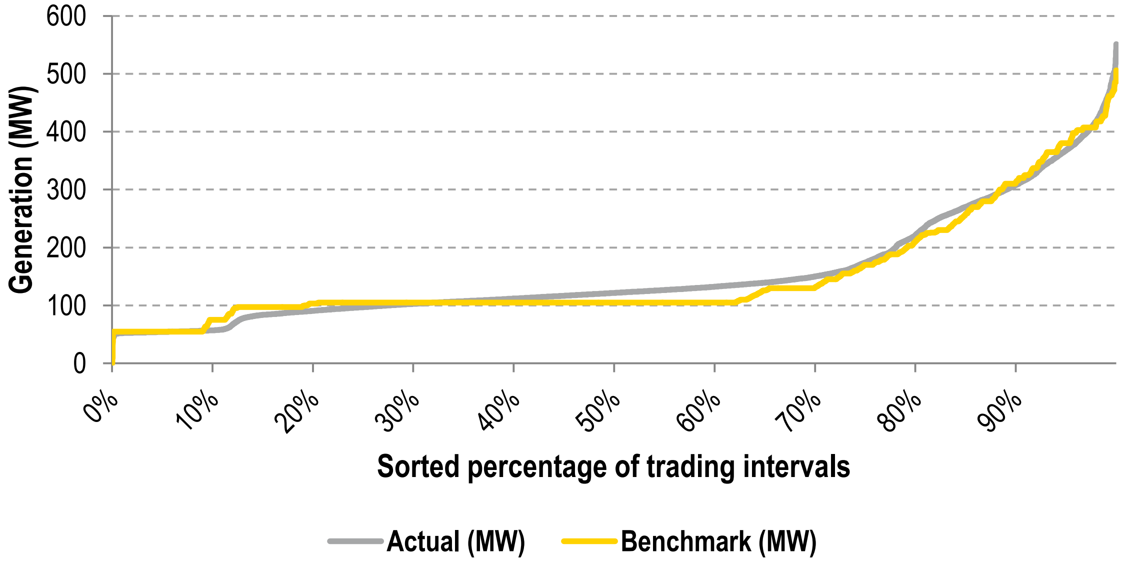
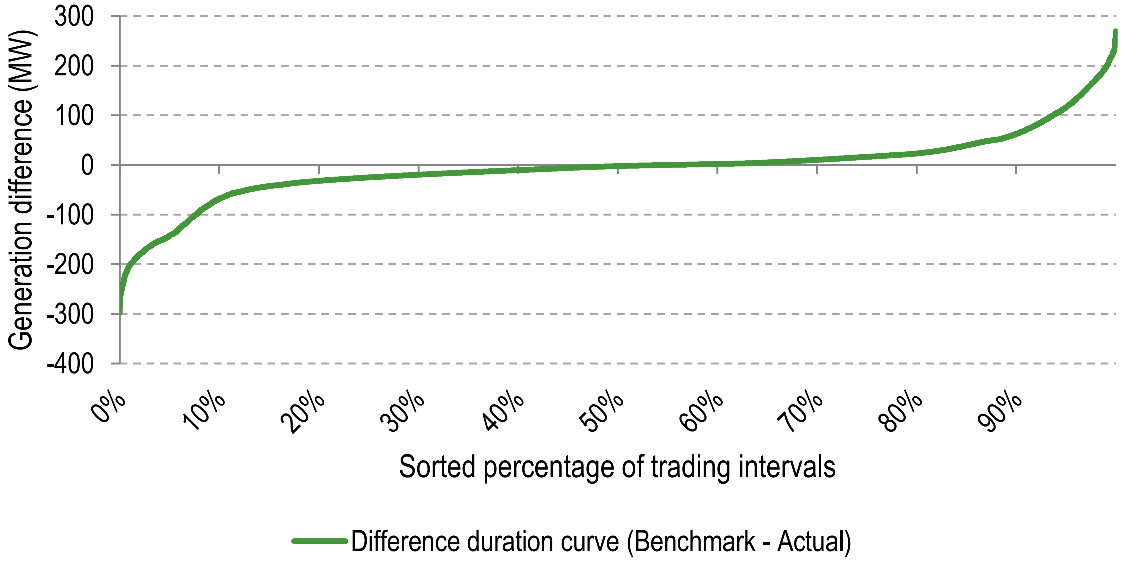


Figure 33 shows the duration curve for the difference between the benchmark and actual generation in each trading interval. The maximum possible difference is the maximum historical generation achieved by units included in the Metro 132 kV region in 2016-17, of ±551 MW. The achieved benchmark result has generation within ±50 MW in 75% of trading intervals. The difference is outside of ±100 MW in 14% of trading intervals.

Figure 33: Generation duration curve of the difference comparing actual and the benchmark simulation for Metro 132 kV



Metro 330 kV

Figure 34 compares the actual and benchmark generation for the Metro 330 kV aggregation using the duration curve over all trading intervals in the year. Overall, production in this region is 0.8% lower in the benchmark than actual. Generation outcomes in the benchmark are a very close match to 2016-17, with slightly fewer high generation trading intervals.

Figure 34: Generation duration curves for Metro 330 kV comparing actual and the benchmark

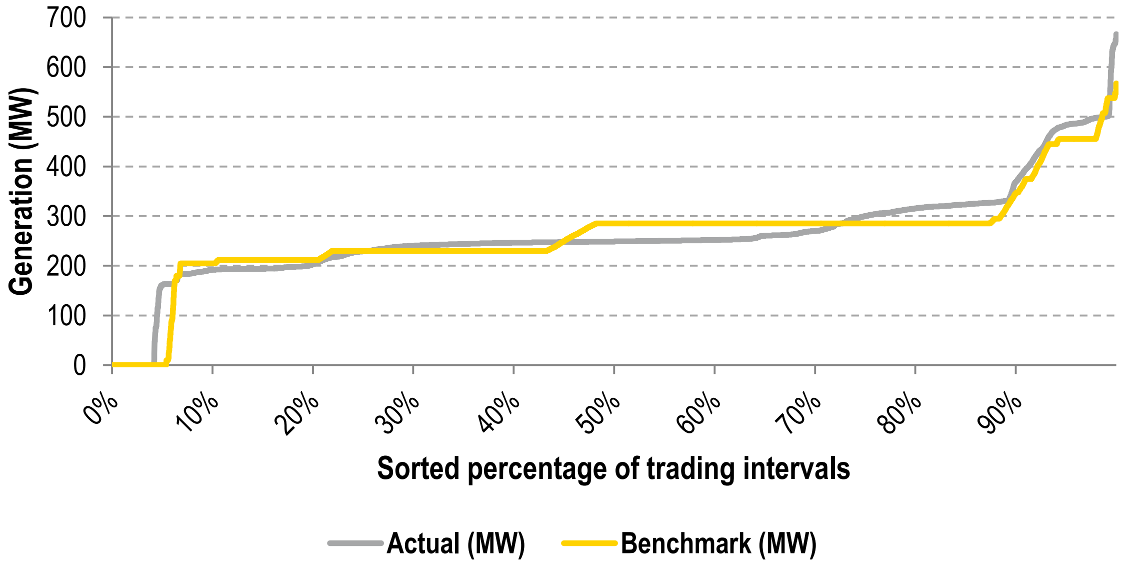
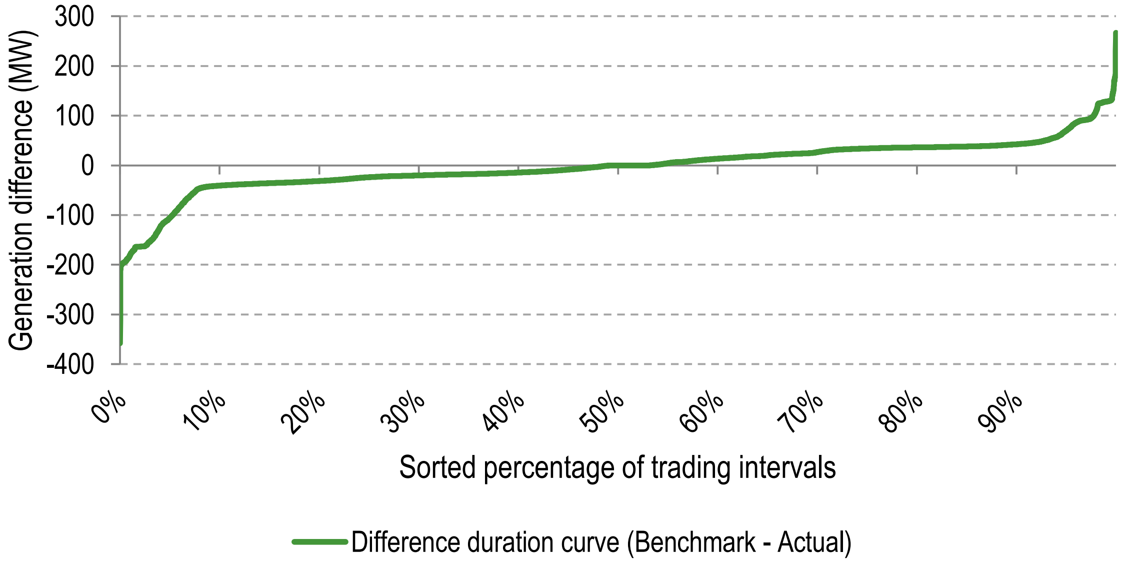


Figure 35 shows the duration curve for the difference between the benchmark and actual generation in each trading interval. The maximum possible difference is the maximum historical generation achieved by units included in the Metro 330 kV region in 2016-17, of ±667 MW. The achieved benchmark result has generation within ±50 MW in 85% of trading intervals. The difference is outside of ±100 MW in 8% of trading intervals.

Figure 35: Generation duration curve of the difference comparing actual and the benchmark simulation for Metro 330 kV



North Country

Figure 36 compares the actual and benchmark generation for the North Country aggregation using the duration curve over all trading intervals in the year. Overall, production in this region is 2% higher in the benchmark than 2016-17.

Figure 36: Generation duration curves for North Country in 2016-17 and the benchmark

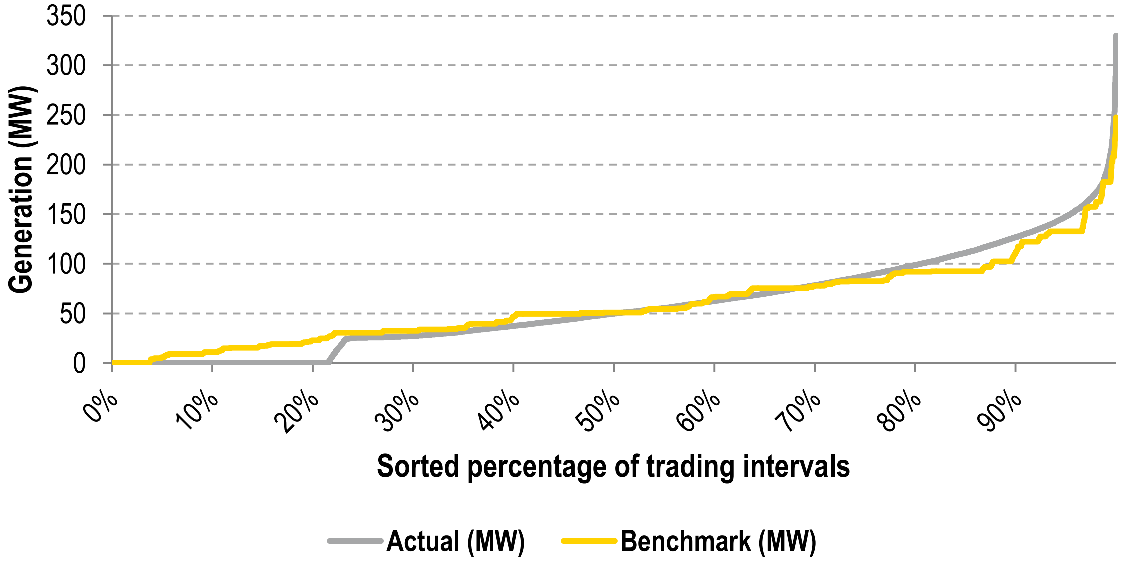
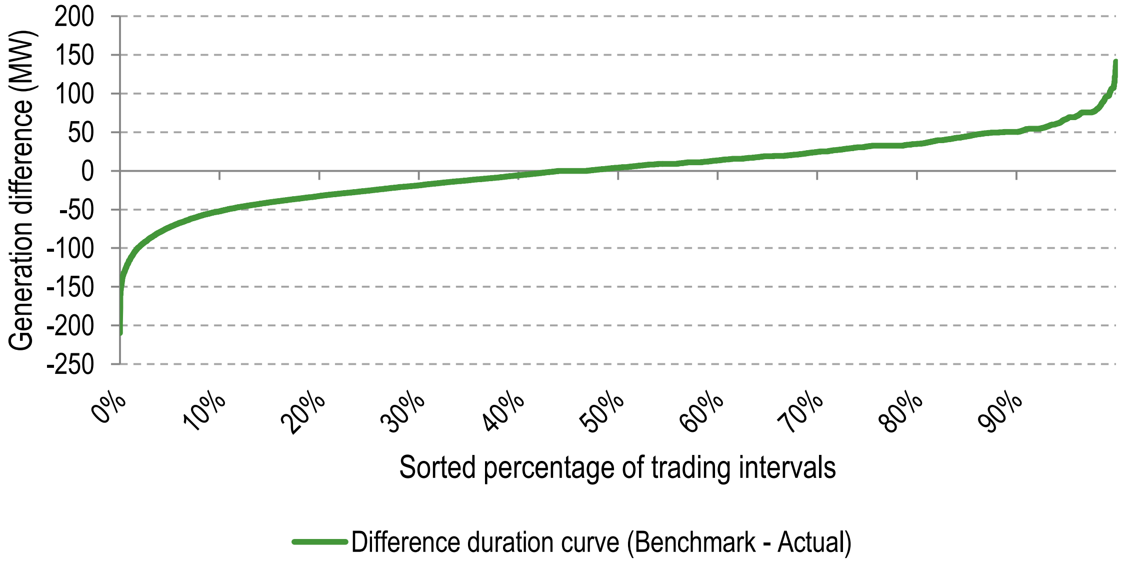


Figure 37 shows the duration curve for the difference between the benchmark and actual generation in each trading interval. The maximum possible difference is the maximum historical generation achieved by units included in the North Country region in 2016-17, of ±330 MW. The achieved benchmark result has generation within ±50 MW in 78% of trading intervals. The difference is outside of ±100 MW in just 2% of trading intervals.

Figure 37: Generation duration curve of the difference comparing actual and the benchmark simulation for North Country



South Country 132 kV

Figure 38 compares the actual and benchmark generation for the South Country 132 kV aggregation using the duration curve over all trading intervals in the year. Generation in this area 0.5% higher in the benchmark than actual.

Figure 38: Generation duration curves for South Country 132 kV comparing actual and the benchmark

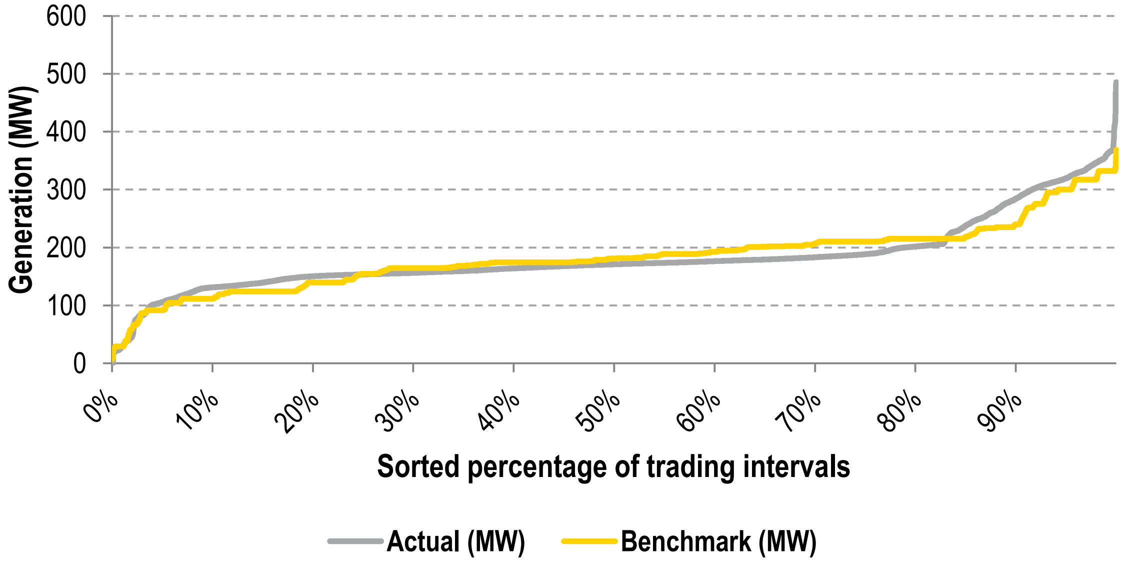
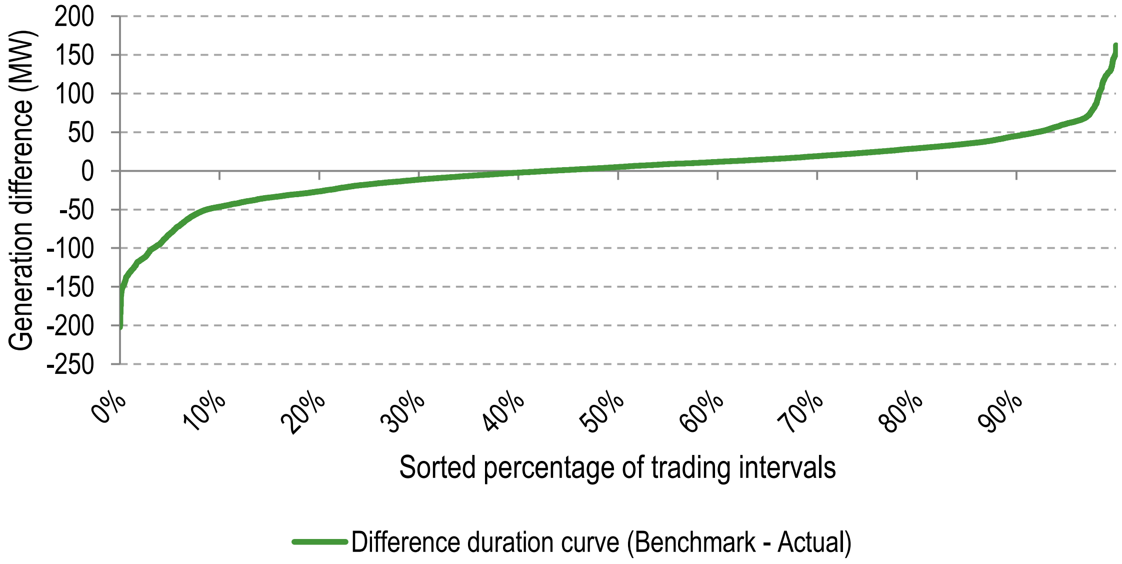


Figure 39 shows the duration curve for the difference between the benchmark and actual generation in each trading interval. The maximum possible difference is the maximum historical generation achieved by units included in the South Country 132 kV region in 2016-17, of ±486 MW. The achieved benchmark result has generation within ±50 MW in 83% of trading intervals. The difference is outside of ±100 MW in 5% of trading intervals.

Figure 39: Generation duration curve of the difference comparing actual and the benchmark simulation for South Country 132 kV



South Country 330 kV

Figure 40 compares the actual and benchmark generation for the South Country 330 kV aggregation using the duration curve over all trading intervals in the year. Generation in this area 0.3% higher in the benchmark than actual.

Figure 40: Generation duration curves for South Country 330 kV in 2016-17 and the benchmark

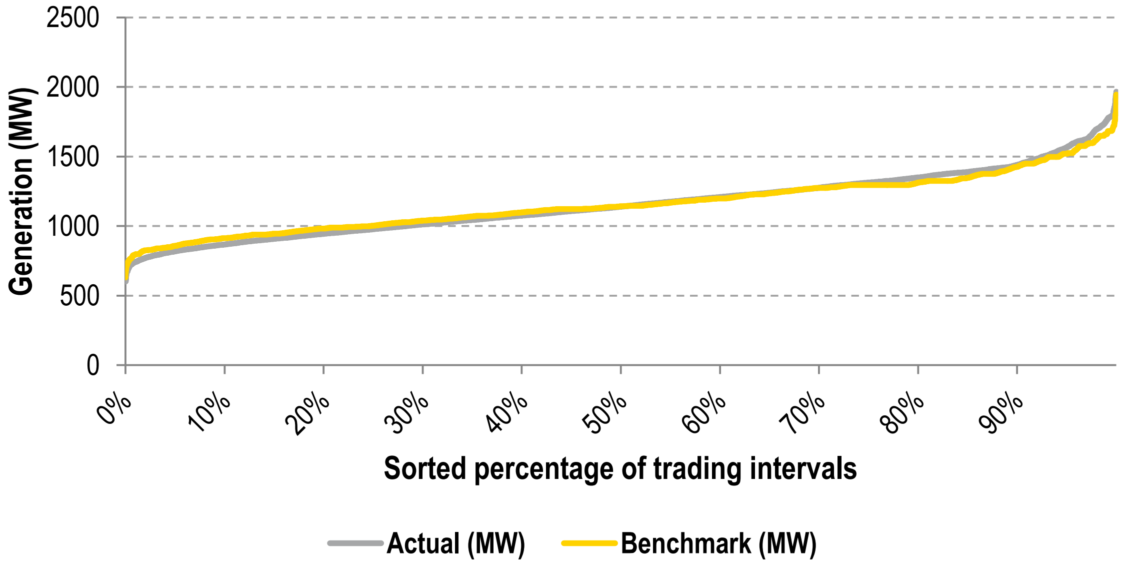
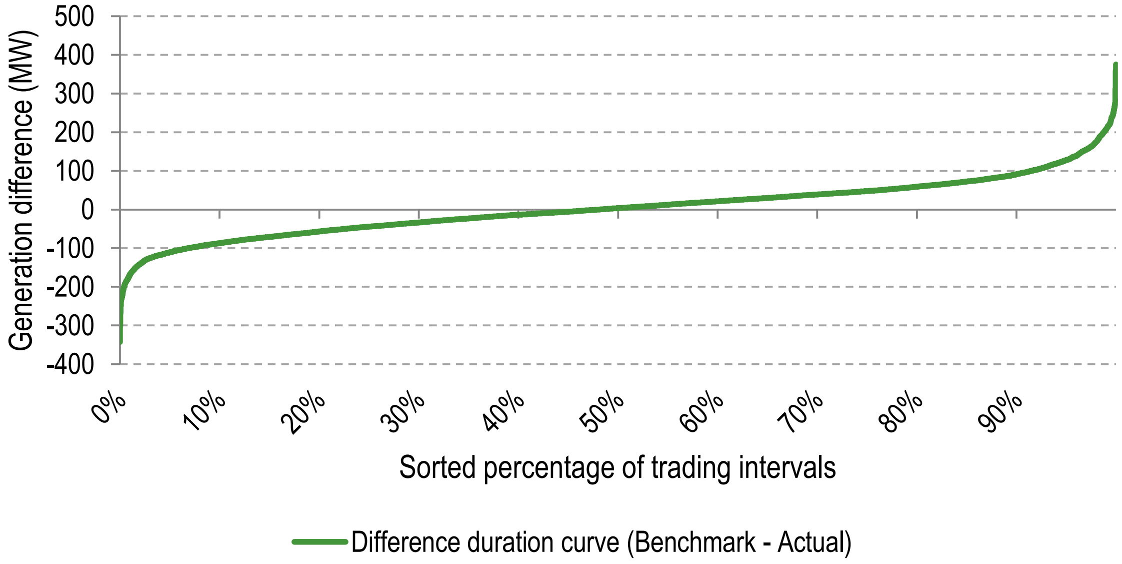


Figure 41 shows the duration curve for the difference between the benchmark and actual generation in each trading interval. The maximum possible difference is the maximum historical generation achieved by units included in the South Country 330 kV region in 2016-17, of ±1,965 MW. The achieved benchmark result has generation within ±100 MW in 85% of trading intervals. The difference is outside of ±150 MW in 5% of trading intervals.

Figure 41: Generation duration curve of the difference comparing actual and the benchmark simulation for South Country 330 kV



A.3.3 Load shedding

No voluntary load shedding (otherwise known as demand-side management (DSM)) nor involuntary load shedding (otherwise known as USE) was reported to have occurred in 2016-17. As such DSM was not simulated for the benchmark and USE did not occur in the benchmarking outcomes.

A.4 Conclusion

The benchmark generation outcomes generally show quite good alignment with historical outcomes for price and at a super station and regional aggregate level. Some particular generating units were difficult to develop static offers for as their operation in 2016-17 is mostly non-price responsive.

Overall the benchmark outcomes are considered reasonable and demonstrate that the static offer set it is fit for purpose to progress the forward-looking market simulation studies.

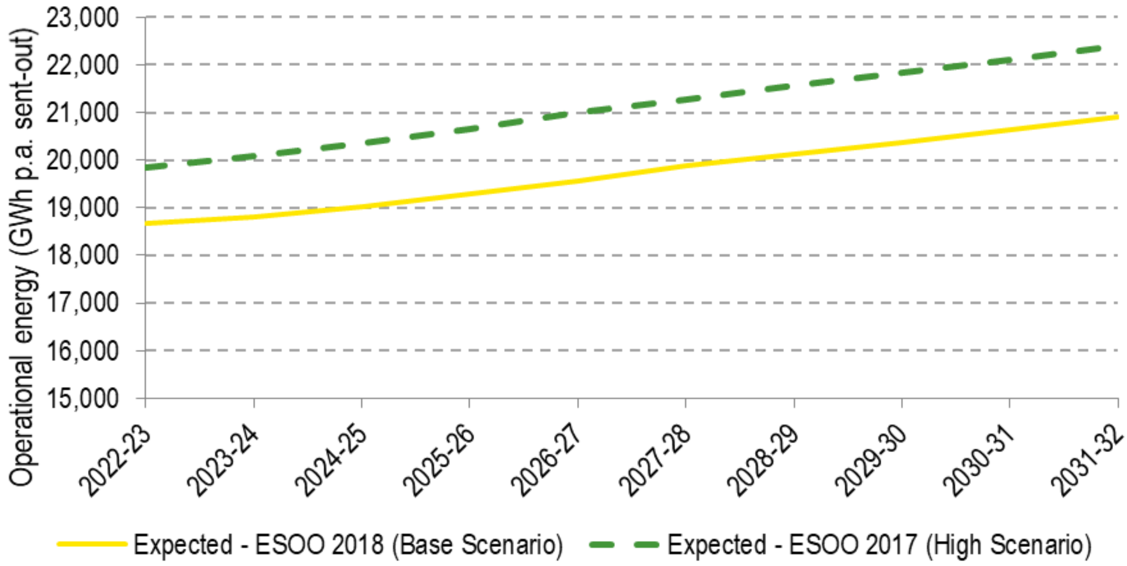
Appendix B Modelling assumptions

An overview of modelling assumptions is provided in this Appendix. A supporting Excel assumptions workbook detailing primary data sets from the public domain is also available.

B.1 Electricity consumption and peak demand

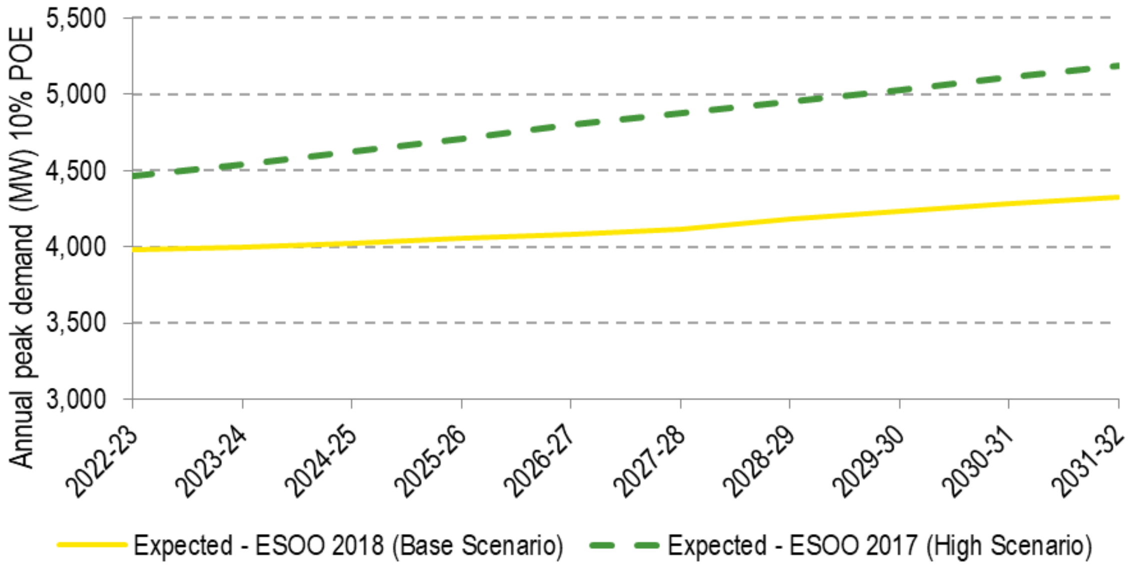
One of the primary considerations when forecasting the electricity market is the future electricity consumption and peak demand. EY has used the data based on the WEM 2017 and 2018 ESOOs as the source of electricity demand and energy projections. Figure 42 shows the trajectories in annual operational energy consumption (to be met by large-scale Registered Facilities). Figure 43 shows the equivalent regional peak demand outlooks for the WEM for the 10% POE projection.

Figure 42: WEM 2017 and 2018 ESOO annual operational energy forecast in the WEM*



* Note that the y-axis has been truncated for clarity.

Figure 43: WEM 2017 and 2018 ESOO annual 10% POE regional peak demand forecast in the WEM*



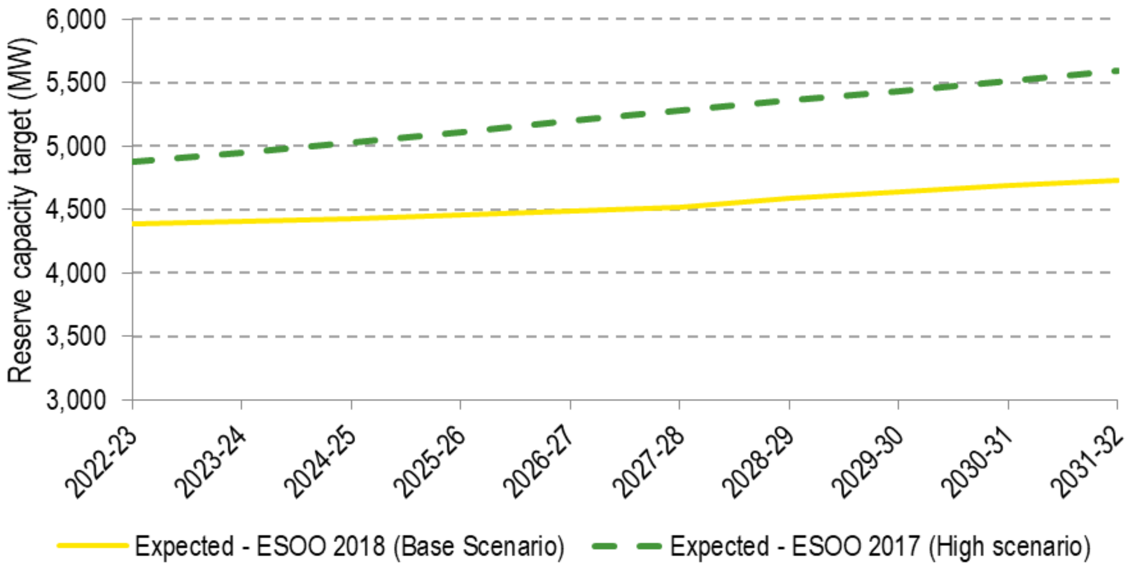
* Note that the y-axis has been truncated for clarity.

Peak demands are materially influenced by weather conditions, particularly hot temperatures in summer and cold temperatures in winter, driving cooling and heating air conditioning loads, respectively. The peak demand (and near-peak demand conditions) increases the risk of price volatility, and therefore the magnitude of the peak demand in any given year is a material factor in determining overall wholesale market pricing trends. Peak demand periods are also typically periods where network constraint equations bind. As with the energy outlooks, the 10% POE and 50% POE peak demand levels forecast by AEMO is modelled based on the WEM 2017 and 2018 ESOOs. The 50% POE peak represents a typical year, with a one in two chance of the peak demand being exceeded in at least one half hour of the year. The 10% POE peak demand represents a one in ten chance of being exceeded in at least one half hour of the year.

B.2 Reserve capacity target

Figure 44 shows the forecast Reserve Capacity Target (RCT) under the 10% POE peak demand trajectories used in the scenarios. The RCT sets the RCR for the relevant Capacity Year. It has been assumed that the contribution to the RCT requirement from intermittent loads, reserve margins and load following remains constant under the each of the scenarios.

Figure 44: Calculated Reserve Capacity Targets for each scenario*

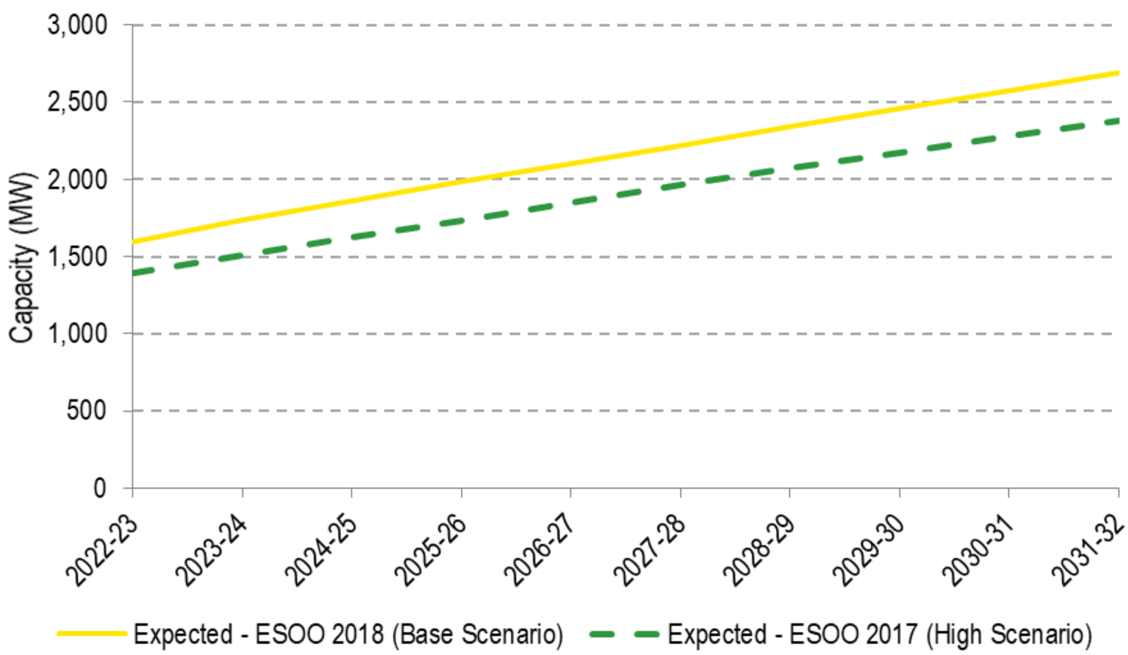


* Note that the y-axis has been truncated for clarity.

B.3 Commercial and residential rooftop PV systems

The uptake in rooftop PV systems has historically been driven by favourable government policies and attractive payback periods. While many of the supportive government policies have now been removed (or significantly scaled back), AEMO still expects significant growth in rooftop PV uptake due to decreasing costs of PV systems and increasing (real or customer perceived) retail energy costs. Figure 45 shows the rooftop PV trajectory for the scenarios.

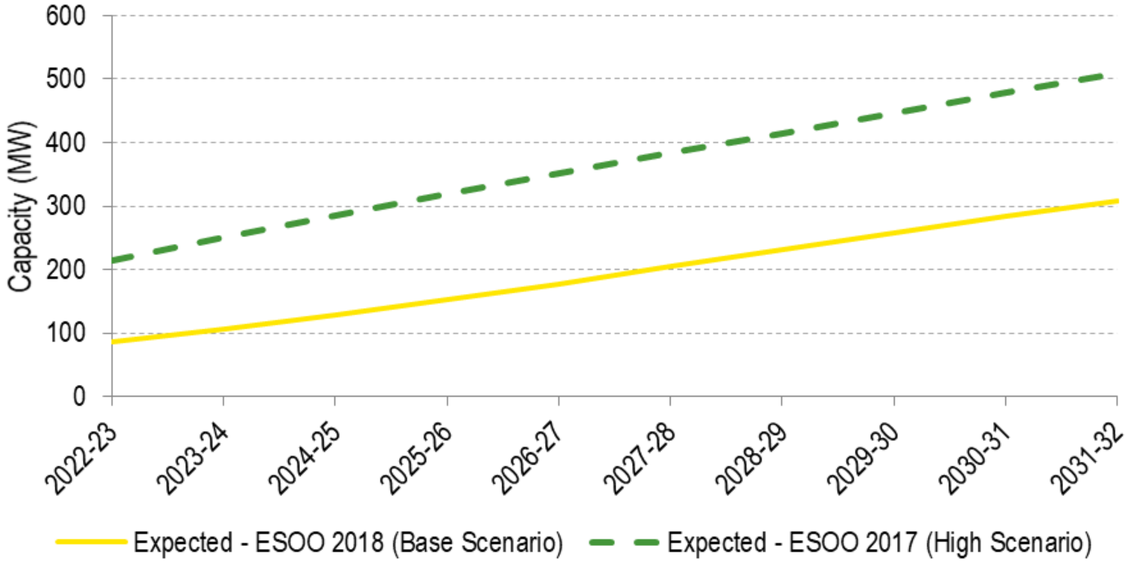
Figure 45: Projections for installed rooftop PV capacity forecast for the WEM used in each scenario



B.4 Behind-the-meter storage uptake

Corresponding with the demand outlooks in the WEM ESOO, AEMO forecasts the uptake of behind-the-meter battery storage. These batteries are assumed to be installed in households and in the commercial sector, in most cases in conjunction with a rooftop PV systems. Large-scale storage would be in addition to these installations. Figure 46 shows the uptake of behind-the-meter battery used in each scenario, as per the WEM 2017 and 2018 ESOOs.

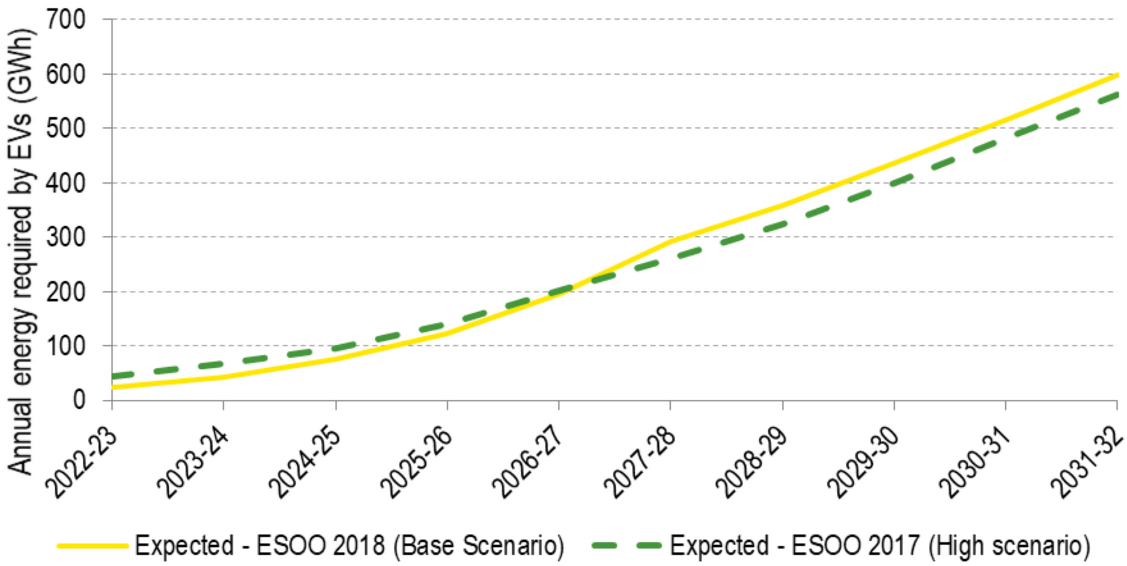
Figure 46: Behind the meter storage uptake for the WEM used in each scenario



B.5 Impact of electric vehicles

All scenarios consider an uptake of EVs providing a new source of electrical load as consumers switch from petrol-based vehicles to those that rely on charging from the grid as part of the decarbonisation effort. Figure 47 shows the assumed annual energy assumed to be required by EVs in each of the scenarios.

Figure 47: EV energy demand trajectories for each scenario



B.6 Thermal generation developments

In accordance with the Energy Minister's directive for the retirement of generation capacity in the WEM, the units listed in Table 17 are assumed to be retired in all scenarios as part of Synergy's 380 MW retirement schedule.[86] Based on a 50-year technical lifetime, no other existing generators are determined to retire within the Study Period.

Table 17: Synergy retirements

Power station	Capacity (MW)	Fuel type	Retirement date
Kwinana Gas Turbine 1	21	Gas	30 September 2018
Muja A (G1, G2)	120	Black coal	Retired
Muja B (G3, G4)	120	Black coal	Out of service
Mungarra Gas Turbine 1, 2, 3	113	Gas	30 September 2018
West Kalgoorlie Gas Turbine 2, 3	62	Gas	30 September 2018

B.7 Large-scale renewable energy target

In June 2015 the Commonwealth Government legislated the revised LRET, ending a protracted review of the policy. The current legislated targets require 33,000 GWh per annum of eligible renewable energy from 2020 to 2030. Additional voluntary certificate surrenders are also expected, due to several state or territory policies, as well as consumer choice schemes such as the GreenPower program.

The WEM's assumed contribution to the LRET in the scenarios is as per the new entrant renewable capacity developments listed in Appendix B.8.

B.8 Renewable capacity developments

Each scenario assumes the same list of new entrant renewable generators will be commissioned in the WEM as driven by the LRET by the commencement of the Study Period on 1 July 2022. The assumed new entrant renewable capacity development schedule for connection in the WEM is listed in Table 18.

Table 18: Assumed new entrant renewable capacity projects commissioned prior to 2022

Commissioning date	Project name	Type	Capacity (MW)	Capacity factor	Reasoning
In service by 1 July 2022	Byford Solar	Solar PV	30	30%	10-year off-take agreement signed with Kleenheat.
	Greenough River 2	Solar PV	30	30%	Project in Synergy's renewable project development.
	Emu Downs Solar Farm	Solar PV	20	30%	Off-take agreement signed to sell LGCs to Synergy up to 2030. Portion of funding from Arena.
	Northam Solar Project	Solar PV	9.9	30%	Part merchant/part PPA. Debt financing secured. Public confirmation of grid connection.
	Badgingarra	Wind	130	44%	12-year off-take agreement signed with Alinta Energy for

[86] Synergy 380 MW announcement

Commissioning date	Project name	Type	Capacity (MW)	Capacity factor	Reasoning
	Wind Farm				bundled energy/LGC.
	Warradarge Stage 1	Wind	180	44%	Project in Synergy's renewable project development.
	Cunderdin Solar Farm	Solar PV	100	30%	Developed on a merchant basis. Public confirmation of grid connection.

B.9 Generator forced and planned outage rates

Table 19 shows the outage rate statistics assumed in the modelling, based on an IMO review of the Planning Criterion[87] and a review of historical data.

Table 19: Forced outage rates statistics from the IMO planning criterion review

Technology	Full forced outage rate (%)	Planned outage rate (%)
Coal	1.72	9.9
Gas (including cogeneration)	3.02	7.8
Gas/liquid fuel	1.06	5.2
Biomass (assumed same as gas liquid)	1.06	5.2
Wind and solar PV	Included in modelled capacity factor	

EY conducts a number of Monte Carlo iterations in the market modelling to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics. As shown in the table, the same outage statistics are applied for generators with the same fuel type.

The nature of outages for wind and solar generators is different to large thermal generating units due to the modular nature of wind turbines or solar panels within a power station.

The capacity factors modelled for wind and solar farms are based on observed and expected output of the wind and solar farms modelled, and as such implicitly include the impact of outages.

B.10 New entrant parameters and capital costs

The technology costs are based on projections published in the 2016 NTNDP report. However, solar PV and wind capital costs have been reduced, in line with views developed from industry consultation. The capital costs for other technologies have remained unchanged. Figure 48 shows the capital costs projections for the main technologies of interest for the Study Period. Table 20 provides a summary of other new entrant parameters, which are primarily from the 2016 NTNDP, except Biomass, which is from AEMO's Integrated System Plan (ISP)[88] assumptions.

[87] IMO 5 Yearly Review of Planning Criterion
[88] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

Figure 48: New entrant capital costs assumed for different technologies

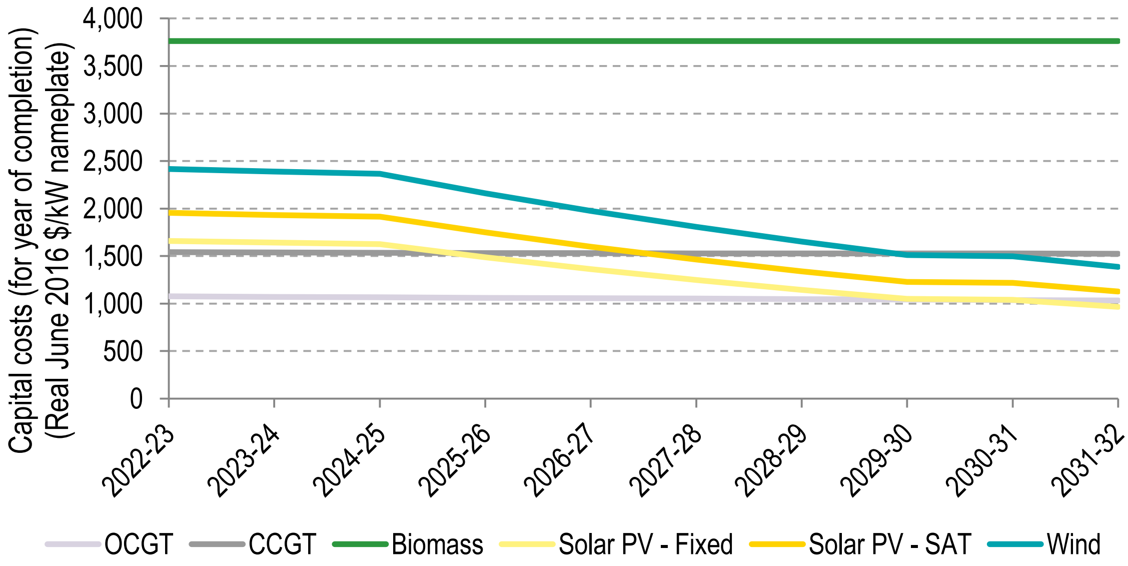


Table 20: New entrant parameters (in June 2017 dollars)

Technology	FOM ($/MW)	VOM ($/MWh sent-out)	Economic life (years)
CCGT	10,147	7.10	30
OCGT	4,059	10.15	30
Solar PV - Fixed	25,367	0	25
Solar PV - SAT	30,440	0	25
Wind	45,660	0	25
Biomass	126,850	8.12	30

Coal prices

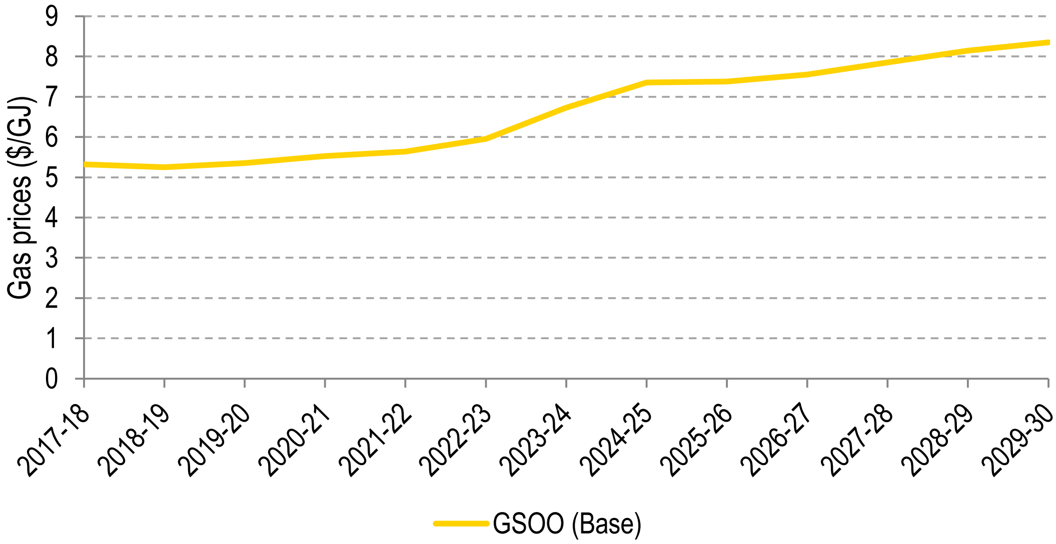
For this Project, EY has assumed that coal prices remain constant at $2.60/GJ in the Study Period.

B.11 New entrant gas prices

EY does not consider the impacts of short-term gas contracts in our modelling, rather considering the pricing effect of long-term gas contracts for gas powered generators. Figure 49 below shows the assumed gas price trajectory for the SWIS for uncontracted gas supplies, based on AEMO's 2017 Gas Statement of Opportunities (GSOO) base scenario.[89] As existing gas generators' current gas contracts roll off, EY expects that these generators will be forced to adopt this price trajectory for their future gas contracts.

[89] https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities

Figure 49: Forecast gas prices for the SWIS (from the AEMO 2017 GSOO)



B.12 New entrant locations and marginal loss factors

In consultation with EY, the PUO devised candidate new entrant locations for different technologies for the capacity mix forecasting in this Project. Table 21 lists the selected candidate new entrant locations and technologies for each, as a result of the public consultation process in March 2018 and some initial modelling.

All MLFs used in the modelling are with reference to Southern Terminal as the RRN. These MLFs were published as part of the public consultation held by the PUO in March 2018. Table 21 shows the MLFs assumed for each candidate new entrant location. A static MLF was assumed for most locations, but for new entrant wind and solar PV in East Country and Eastern Goldfields, a formula-driven MLF was applied that depends on the capacity installed at that location. This is due to these two regions being considered to have MLFs that are much more impacted by the total capacity installed in those regions than in other regions in the WEM.

Table 21: Marginal loss factors applied to each candidate new entrant location

Location	Technologies considered	Static or formula-driven MLF	MLF value or equation
North Country	OCGTs, CCGTs, wind, and solar PV	Static	0.992
Neerabup	OCGTs, CCGTs, wind and solar PV	Static	1.007
Muja	OCGTs, CCGTs, solar PV and biomass	Static	0.974
Bunbury	OCGTs, CCGTs, wind, and solar PV	Static	0.958
Kwinana (132 kV and 330 kV)	OCGTs, CCGTs and solar PV	Static	0.998
Kemerton	OCGTs and CCGTs	Static	0.957
Albany	Wind, and solar PV	Static	0.972

Location	Technologies considered	Static or formula-driven MLF	MLF value or equation
East Country	OCGTs, CCGTs, wind, and solar PV	Formula-driven	1.1 – (0.0005 × total installed wind and solar capacity at Eastern Goldfields)
Eastern Goldfields	OCGTs, CCGTs, wind, and solar PV	Formula-driven	0.973 – (0.00025 × total installed wind and solar capacity at East Country)

Appendix C Weighting 50% POE and 10% POE

The potential for any particular outcome in the electricity market is probabilistic. Various combinations of prevailing customer demand, availability and costs of conventional and intermittent generation, energy storage devices, demand side participation, transmission network capability and availability will influence market outcomes.

In the absence of time constraints and data availability considerations the modelling would ideally apply a very wide range of key factors such as atmospheric conditions and peak demand and simply weight each event equally. Monte Carlo iterations of unplanned outage events on generation and transmission elements are each considered to be equally likely. The sample of two reference years for atmospheric conditions and 'load shape' are also considered to be equally likely for the purpose of the modelling. Ideally we would model a large number of POE peak demand conditions but the computation time would be intractable. To manage the problem size, we limit POE peak demand samples to 10% and 50% POE scenarios.

In order to establish the expected outcome for unserved energy from these samples we assume that the probability density function of the demand POE samples are normally distributed. We then seek to find the quantum of the cumulative distribution function exceeding the 90th, 50th and 10th percentile. It is found that 30.4% of the cumulative distribution is contained above the 10th percentile, 30.4% is below the 90th percentile and 39.2% between the 10th and 90th percentile. As peak demand expectation reduces the chance of unserved energy also reduces. We therefore make a conservative approximation that the unserved energy expectation is similar for all POEs below the 50% POE peak demand forecast. It then follows that we establish the expected unserved energy from the Monte Carlo simulations as follows in equation (1).

$$\begin{aligned} Expected\ USE = {} & 0.304 \times Avg\ of\ 10\%\ POE\ USE\ (2\ Ref\ Years\ \times 25\ Monte\ Carlo\ simulations\ ) \\ & + 0.696 \times Avg\ of\ 50\%\ POE\ USE\ (2\ Ref\ Years\ \times 25\ Monte\ Carlo\ simulations) \end{aligned} \quad (1)$$

EY applies a rounded 0.3 weighting on all 10% POE outcomes and 0.7 weighting on 50% POE outcomes. While the above analysis is for USE specifically, EY applies the weightings to all outcomes (such as generator revenues and prices) for simplicity.

Appendix D Glossary and acronyms

Defined terms	
Benchmarking	The process of iteratively comparing simulated outcomes from a model with observed outcomes from actual data to test the accuracy. Usually involves iterative adjustments to input parameters and/or the methodology
Benchmark Reserve Capacity Price	As defined within the Market Rules, in respect of a Reserve Capacity Cycle, the price in clause 4.16.2 as revised in accordance with section 4.16 of the rules
Bid	See Offer.
Bid band	A facility's offer of generation (or load) into the balancing market, which comprises a price in $/MWh and a quantity in MW.
Capex	Capital expenditure
Capacity Credit	A unit of Reserve Capacity assigned to a Facility during a Capacity Year where each Capacity Credit is equivalent to 1 MW of Reserve Capacity
Capacity factor	The capacity factor expresses the total energy dispatched from a generator, or group of generators, as a percentage of the maximum possible energy if the generators were dispatched at full output for the whole year.
Capacity Year	A 12-month period commencing on 1 October.
Constrained network access	Where generators are dispatched taking into account defined transmission network limitations and power system security limits
Expected unserved energy	As defined within the Market Rules, an estimate, expressed in MWh, of energy demanded, but not supplied, as a result of involuntary load shedding in the SWIS
Fully constrained network access	A term used to describe a network access regime for the WEM where all existing generators and any new entrant generators connecting to the electricity network are subject to generation curtailment in response to network congestion identified within the market operators central dispatch engine
Long Term Planning Criterion (or Planning Criterion)	As defined within clause 4.5.9 of the Market Rules
Long Term Planning Horizon	The 10-year period commencing on 1 October of Year 1 of the Reserve Capacity Cycle
Market Rules	The Wholesale Electricity Market Rules made under the Regulations and contemplated by section 123 of the Electricity Industry Act 2004
Offer	A set of bid bands a facility (or the Synergy portfolio) makes in the balancing market that is used to form a balancing market merit order in order to dispatch generators at the lowest price to meet demand.
Partially constrained network access	A term used to describe a network access regime in the WEM where some new entrant generators connecting to the electricity network are subject to generation curtailment in response to network congestion identified within the market operators central dispatch engine. All incumbent generators are not subject to dispatch curtailment.

Reserve Capacity Cycle	A four year period covering the events defined within Chapter 4.1 of the Market Rules
Reserve Capacity Price	As defined within the Market Rules and in respect of the Reserve Capacity Cycle, the price for Reserve Capacity expressed in $ per MW per year
Reserve Capacity Target	As defined within the Market Rules and in respect of a Capacity Year, an estimate of the total amount of generation or Demand Side Management capacity required in the SWIS to satisfy the Planning Criterion for that Capacity Year
Trading interval	A 30-minute dispatch period in the WEM.

Acronyms

2-4-C®	EY's in-house wholesale electricity market dispatch modelling software suite
AEMO	Australian Energy Market Operator
BOM	Bureau of Meteorology
BRCP	The Benchmark Reserve Capacity Price, as defined in the Market Rules
CF	Capacity factor
CPI	Consumer price index
DSM	Demand-side management
EV	Electric vehicle
FOM	Fixed operation and maintenance
FOR	Forced outage rate
GIA	Generator Interim Access
GWh	Gigawatt-hour
GSOO	Gas Statement of Opportunities, as published by the Australian Energy Market Operator annually.
LCOE	Levelised cost of energy ($/MWh). Equivalent to the long-run marginal cost (LRMC).
LGC	Large-scale generation certificates
LRET	Large-scale renewable energy target
MLF	Marginal loss factor (also called transmission loss factor)
MWh	Megawatt-hour
NEG	National Energy Guarantee
NEM	National Electricity Market
NEM ESOO	Electricity Statement of Opportunities for the NEM, as published annually by AEMO
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
POE	Probability of exceedance

PUO	The Public Utilities Office
RCM	Reserve Capacity Mechanism
RCC	Reserve Capacity Cycle
RCP	Reserve Capacity Price
RCT	Reserve Capacity Target
RRN	Regional reference node
SAM	System Advisory Model, from the National Renewable Energy Laboratory for developing locational solar PV generation profiles
SAT	Single-axis tracking
SEST	EY's in-house solar energy simulation tool
SWIS	South-West Interconnected System, which comprises the entire interconnected power system in south-west Western Australia
USE	Unserved energy, expressed as percentage of a region's energy demand
VOM	Variable operation and maintenance
WA	Western Australia
WACC	Weighted-Average Cost of Capital
WEM	Wholesale Electricity Market, which comprises the electricity market operating in south-west Western Australia
WEM 2017 ESOO	Electricity Statement of Opportunities for the WEM, as published annual by AEMO
WEST	EY's in-house wind energy simulation tool

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