

Wholesale Electricity Market modelling and backcasting report

Australian Energy Market Operator
31 August 2018

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Ernst & Young (“we” or “EY”) has been engaged by the Australian Energy Market Operator (“you”, “AEMO” or the “Client”) to provide electricity market modelling services to assist AEMO in calculating a number of market parameters in accordance with the Western Australian Wholesale Electricity Market Rules (the “Services”), in accordance with our Assignment commencing 1 August 2018, under the Master Services Consultancy Agreement entered into by AEMO and EY commencing 5 December 2016.

The enclosed report (the “Report”) provides an overview of the simulation model and the generic data inputs and assumptions to be used in delivering the Services. The simulation model will form the basis for the outputs produced and either have been, or will be, agreed with AEMO, following the end of a public consultation process and after due consideration of submissions received.

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Table of contents

1.	Introduction	3
1.1	Background	3
1.2	Provision of ancillary services	4
1.3	Ancillary service market parameters	4
1.4	Report structure	5
2.	Modelling the Wholesale Electricity Market	6
2.1	Wholesale electricity market modelling	6
2.2	Data and input assumptions	6
2.3	Simulation parameters	13
2.4	Key data used in calculation of market parameters	14
3.	Backcasting.....	15
3.1	Backcasting inputs and assumptions	15
3.2	Backcast simulation approach	18
3.3	Bidding profile development.....	18
3.4	Results.....	19
Appendix A	Generation duration curves and time of day profiles by station	29

1. Introduction

EY has been engaged by AEMO to provide electricity market modelling services to assist AEMO in calculating market parameters in accordance with the Western Australian Wholesale Electricity Market Rules (Rules).

The objective of the modelling project (Project) is to calculate:

- ▶ The proposed Margin_Peak and Margin_Off-Peak values (Margin Values) for 2019-20 and for the purpose of clause 3.13.3A(a)(i) and 3.13.3A(a)(ii) of the Rules.
- ▶ The proposed SR_Capacity_Peak and SR_Capacity_Off-peak values (SR Capacity Values) for 2019-20 and for the purpose of clause 3.22.1(e) and 3.22.1(f) of the Rules.
- ▶ The proposed Load Rejection Service Cost for the period from 2019-20 to 2021-22 for the purposes of clause 3.13.3B(a) of the Rules.

This Report provides an overview of the model used to simulate the Wholesale Electricity Market (WEM) in Western Australia, including a description of the key inputs and outputs used in providing the Services. This Report forms the first deliverable as part of AEMO's public consultation on the 2019-20 Margin Value review and describes the inputs and outputs generically.

A report detailing the proposed modelling methodologies and specific data and input assumptions to be used in the modelling will be released to facilitate public consultation and to seek feedback from Market Participants¹ on parameters associated with their generation facilities.

As part of the Project to date, EY has completed a backcasting exercise of half-hourly modelling of the WEM. The objective of the backcast is to construct calibrated bidding profiles² for each generator to emulate observed generation dispatch patterns and WEM Balancing Prices³ for the 2017-18 financial year. The bidding profiles are then used in subsequent market model simulations of the WEM to forecast future dispatch of existing generators and Balancing Prices under a set of case assumptions for the relevant study year.

In preparing this Report, we have used information that has been made publicly available through industry consultations and various industry publications to the extent practicable. We note that the initial set of assumptions have been selected by AEMO based on consultation between EY and AEMO. We note that there is a significant range of alternative 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

AEMO is required to determine, procure, schedule and dispatch generation facilities to meet the ancillary service requirements in accordance with the Rules. The modelling undertaken here is focused on the following two ancillary services in the WEM:

- ▶ **Spinning Reserve Ancillary Service (SRAS):** which is the service of holding online capacity associated with a synchronised generator, a dispatchable load or an interruptible load in

¹ As defined in the Rules

² Bidding profiles are a collective set of price-quantity pairs offered into the WEM in Balancing Submissions used in forming the Balancing Merit Order.

³ Balancing Price as defined in the Market Rules

reserve to respond to a frequency event associated with a contingency event involving either the loss of a single generator unit or a single transmission network element⁴.

- ▶ **Load Rejection Reserve Service (LRRS):** which is the service of holding online capacity associated with a synchronised generator or dispatchable load in reserve to respond to the sudden decrease of system load.

In setting the ancillary service requirements, AEMO must consider the ancillary service standards and the SWIS operating standards as defined within the Rules.

- ▶ **SRAS requirements:** AEMO is required to ensure sufficient spinning reserve to cover the loss of 70% of the generator with the highest total output in a particular period. This may be relaxed if AEMO expects that the shortfall will be intermittent in nature and last no longer than thirty minutes⁵. The SRAS requirement is dynamic and varies from period to period. It is dependent upon generation dispatch outcomes in each period.
- ▶ **LRRS requirements:** The amount of load rejection reserve must ensure that system over-frequency is below 51 Hz for credible load rejection⁶ events. The largest credible load rejection event is typically set by the loss of a network transmission element (for example, the loss of the 220 kV transmission circuit supplying the Eastern Goldfields region). This value has been determined to be 120 MW by AEMO⁷. This may be relaxed by up to 25% (or 90 MW) by AEMO where it considers the probability of a network transmission fault is rare.

1.2 Provision of ancillary services

There is currently no market for the provision of SRAS or LRRS with Synergy acting as the default service provider. AEMO may contract with individual market participants to provide these services if these services can be provided at a lower cost compared to Synergy⁸. AEMO procured a total of 68 MW through spinning reserve contracts for the 2018-19 year through a long-term interruptible load contract (42 MW) and two short-term contracts with scheduled thermal generators (26 MW in total)⁵.

Synergy also acts as the default provider of LRRS through capable generators in the Balancing Portfolio⁵. Generators are not explicitly dispatched or enabled to be provide this service, but do so naturally based on their generator output in a period taking into account their minimum stable generation value.

1.3 Ancillary service market parameters

The cost of providing these services are borne by market participants through ancillary service settlement calculations⁹, which use administered market parameters proposed annually by AEMO and determined by the Economic Regulation Authority (ERA). The parameters that are the focus of this modelling are outlined in Table 1. These parameters are calculated and proposed to the ERA for use in regulatory determinations.

⁴ Whilst Clause 3.9.2 of the Rules does not explicitly refer to transmission network outages, the proposed Spinning Reserve requirement as part of AEMO's Ancillary Service determination sets the requirement to be the maximum of 70% of the output of largest generating unit and 70% of the largest contingency event that would result in generation loss. Transmission network outages are taken into account when considering contingency events.

⁵ [AEMO 2018-19 Ancillary Service Report](#)

⁶ Loss of load

⁷ AEMO determines the load rejection reserve requirement. A 120 MW value has been proposed by 2018-19. This is assumed to be applicable to the 2019-20 year.

⁸ <https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Security-and-reliability/Ancillary-services>

⁹ Clause 3.13 and 9.9 of the WEM Rules

Table 1: Market parameters to be determined as part of this Service

Parameter	Description
Margin_Peak; Margin_Off-Peak	<p>Margin Values are used to compensate Synergy as the default provider of spinning reserve and represents the opportunity cost associating with making capacity available for the service.</p> <p>Margin Values are applied to the Balancing Price and the quantity of spinning reserve provided to determine an 'availability payment' to Synergy. This payment is defined in the settlement equation in clause 9.9.2(f) of the Rules.</p> <p>Margin Values are calculated for peak¹⁰ and off-peak trading intervals.</p>
SR_Capacity_Peak; SR_Capacity_Off-Peak	<p>The SR_Capacity Values represent the required SRAS quantity and is used in the determination of Margin Values.</p> <p>These values are also used in settlement equation for the purposes of clause 9.9.2(f) of the Rules.</p> <p>SR_Capacity values are calculated for peak and off-peak trading intervals.</p>
Cost_LR Value	<p>The Cost_LR parameters represents the payment to a market generator for the costs of providing LRRS and the system restart services.</p> <p>Generators that provide LRRS are compensated through the "L" parameter.</p> <p>Generators capable of providing system restart services, that is, are capable of 'black-starting' for energising the transmission network and other generators following a system black out, are compensated through the "R" parameter.</p>

1.4 Report structure

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

- ▶ Section 2 presents a high level overview of the wholesale electricity market model and its proposed application for this Service, including descriptions of the generic inputs and outputs.
- ▶ Section 3 summarises EY's backcasting against the 2017-18 reference year for the Balancing Price and generator dispatch outcomes.
- ▶ Appendix A shows generation duration curves and time of day profiles for each station modelled in the backcasting exercise.

¹⁰ Peak trading intervals are defined for the time between 8:00am and 10:00pm.

2. Modelling the Wholesale Electricity Market

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 bidding patterns and availabilities to meet regional demand in a period.

The WEM is modelled as a single node gross pool dispatch energy market. Modelling for this Project is on a trading interval (30 minute) granularity in a time-sequential manner. This captures the variability of renewable generation, thermal unit outages (both unplanned and planned) and ramp rate limitations as well as the underlying changes to system demand.

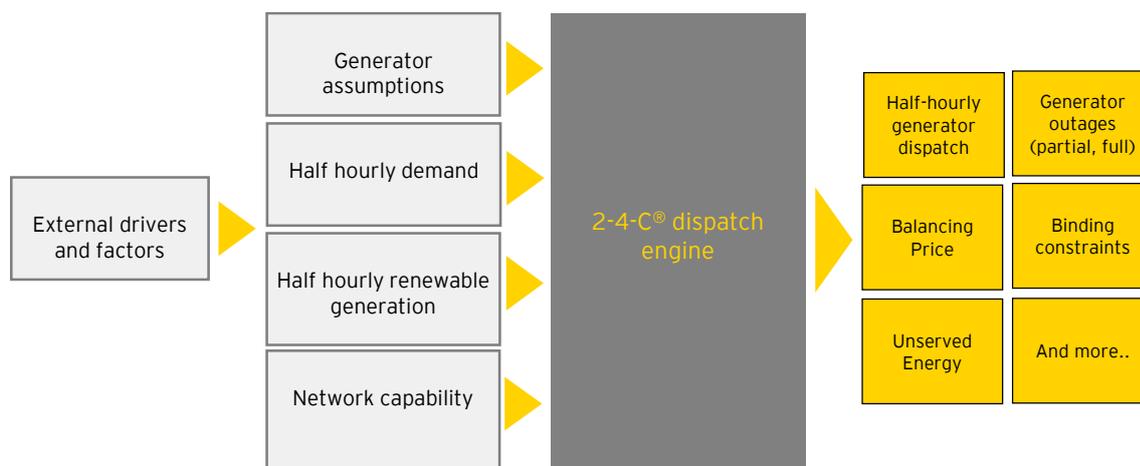
At a high level, for each trading interval in the defined study period, 2-4-C[®] simulates the dispatch of generators to meet a forecast load demand target subject to defined constraints. Constraints in the model can represent a range of physical limits associated with network power transfer limits,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

Each generator unit is modelled individually. The outputs that are reported from the model include the output of each generator (in MW or GWh), the loss factor adjusted market clearing price¹¹ (in \$/MWh), presence of unserved energy (USE)¹² and generator availability amongst many other metrics.

2.2 Data and input assumptions

In practice, electricity market modelling of this nature is highly complex and involves establishing a large set of data and input assumptions that are often inter-related. These input assumptions can be grouped into four general categories which are described at a high level below. Figure 1 provides a high level overview in diagram form, including categorising the input assumptions in four categories.

Figure 1: Simplified high level overview of the inputs and outputs to 2-4-C[®]



¹¹ The Balancing Price, constrained by maximum and minimum energy price limits

¹² Unserved energy can be the result of voluntary or involuntary load shedding. Voluntary load shedding is modelled as Demand Side Participation offering into the market as a response to high pricing events. Involuntary load shedding is the result of insufficient capacity to meet the load demand in a trading interval, requiring system load to be curtailed and occurs as a last resort.

The following points describes the four types of input assumptions in Figure 1:

- ▶ **Generator assumptions** are the relevant technical and cost parameters for each existing and new entrant generator in 2-4-C[®]. These assumptions include generator bidding profiles¹³, generator heat rates, ramp rates, fuel costs, fixed and variable operating and maintenance costs, emissions factors, outage rates (including mean time to repair and mean time to fail), marginal loss factors, planned maintenance periods, new entrant technology capital costs and more¹⁴.
- ▶ **Half hourly demand** involves using half hourly data trace based on assumptions of peak demand and annual energy projections, historical half-hourly demand, the uptake of rooftop solar PV, electric vehicles (EVs) and behind-the-meter battery storage, using data sourced primarily from AEMO's Electricity Statement of Opportunities (ESOO)¹⁵. EY's half-hourly profile modelling tools combine these together to produce forecasts of the future half-hourly demand.
- ▶ **Network capability** defining power transfer limits and network limitations that constrain the physical dispatch of generator units and dispatchable loads. In actual market dispatch and 2-4-C[®], these are typically implemented in the form of network constraint equations¹⁶. However, the WEM currently operates without network constraint equations implemented in generation dispatch processes. Management of network constraints is currently facilitated by a number of post-contingent generation curtailment schemes and manual intervention by system operators if required.
- ▶ **Renewable generation modelling** involves developing half-hourly available generation profiles for each modelled wind or solar farm. The input assumptions and data include historical wind and solar resource data that is used to create expected/historical annual energy production¹⁷.

Some of the input assumptions are processed in models external¹⁸ to the 2-4-C[®] dispatch software to determine the quantities to be used.

Figure 2 shows a detailed flow diagram detailing the interactions between 2-4-C[®].

¹³ Determined in this Project as a result of the backcasting exercise.

¹⁴ Currently, generator synchronisation times are not explicitly modelled. Implementation of synchronisation times will be considered in the formulation of the modelling methodology.

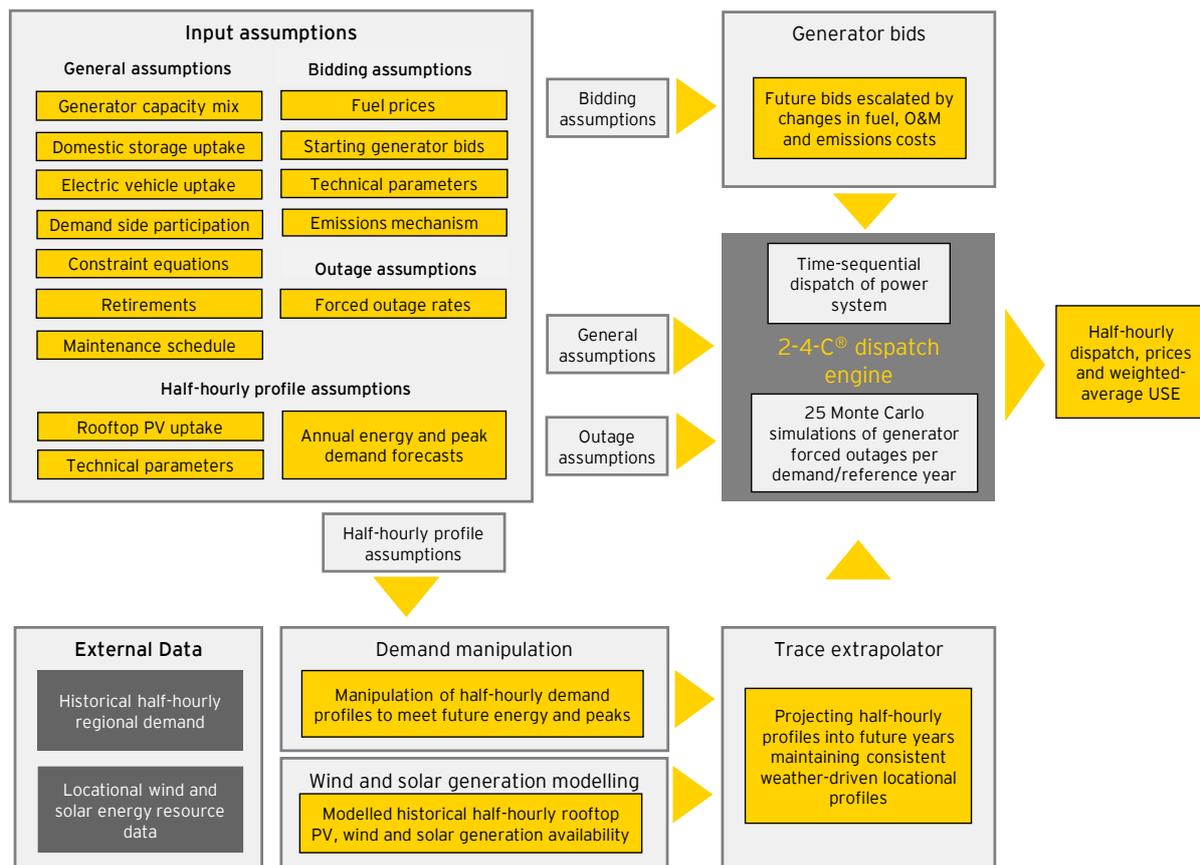
¹⁵ [AEMO Electricity Statement of Opportunities](#)

¹⁶ 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. The WEM does not automatically apply network constraint equations in dispatch, however, PUO reform packages are expected to be in place by 2022.

¹⁷ Landfill/biomass generators are treated as thermal generators.

¹⁸ An example of an external assumption not used directly in the dispatch modelling for the WEM is the Reserve Capacity Requirement. This may impact forward looking generator capacity requirements by setting the Capacity Credit requirement and the surplus used in calculating the Reserve Capacity Price. However, it is not explicitly used in dispatch modelling.

Figure 2: Data flow diagram for the market simulations



2.2.1 Generator assumptions

Generator units modelled

All existing in-service generators are modelled taking into account publicly announced generator retirements within the study period. The following new entrant generators are included based on capacity credit certification within the study period.

Table 2: Assumed new entrant renewable capacity projects commissioned prior in 2019-20

In-service date	Project name	Technology type	Capacity (MW)
1-10-2019	Badgingarra Wind Farm	Wind	130
	Merredin Solar Farm	Solar PV	120

In accordance with the Energy Minister’s directive for the retirement of generation capacity in the WEM, Synergy’s 380 MW retirement schedule¹⁹ is modelled.

¹⁹ [Synergy 380 MW announcement](#)

Table 3: 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	30 April 2018
Muja B (G3, G4)	120	Black coal	30 April 2018
Mungarra Gas Turbine 1, 2, 3 ²⁰	113	Gas	30 September 2018
West Kalgoorlie Gas Turbine 2, 3 ¹⁹	62	Gas	30 September 2018

Generator bidding

EY uses a set of bidding profiles derived from backcasting for each generator that depict their typical bidding behaviour as reflected in observed market data with respect to their short-run marginal cost. For most generators their bidding behaviour can be represented with one static bid for a given SRMC. Some generators require multiple bidding profiles that apply to particular periods of time (such as off-peak and peak periods) to reflect patterns in varying operating conditions such as fuel availability.

A bidding 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. For example, a coal unit may typically bid a certain proportion of its capacity 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 its expected short-run marginal costs that vary based on their operating state and fuel costs.

In each forward-looking year the bids for each generator are adjusted according to computed changes in their SRMC, which is based on the assumed annual applicable fuel price (and emissions costs, if relevant). These adjustments are only made to bid prices in a profile that are a function of the SRMC (i.e., this would not apply to bids 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 the scenario assumptions chosen, EY increases the maximum energy price limits accordingly, based on associated fuel price uplift and additional costs associated with emissions (if applicable).

Since the operating conditions for most generators are confidential, EY determines suitable bidding profiles for each generator using a backcasting process. This involves simulating the half-hourly dispatch and prices for a historical year with 2-4-C[®], and adjusting the bidding profiles for each generator with an iterative process to reproduce actual dispatch and pricing outcomes as close as possible, taking into account observed generation data (such as minimum generation values). The key data inputs and assumptions used in the backcasting process are discussed further in Section 3.

Note that Synergy currently bids its Balancing Portfolio 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.

Fuel costs

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. The assumed gas price trajectory for the SWIS for uncontracted gas supplies is based on publicly available information, typically AEMO's Gas Statement of Opportunities (GSOO)²¹. As existing gas generators' current gas

²⁰ The Mungarra and West Kalgoorlie Power Stations have been announced for retirement by 30 September 2018 and are not expected to operate during normal operating states.

²¹ <https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities>

contracts roll off, EY expects that these generators will be forced to adopt this price trajectory for their future gas contracts.

Forced outage rates

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. The same outage statistics are applied for generators with the same fuel type. A 'mean time to repair' and a 'mean time to fail' value is assigned to each generator in the simulation. A unit on a forced outage is excluded from the Balancing Merit Order.

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.

Planned maintenance

Planned maintenance of units throughout the study period is modelled in future years based on available information on scheduled outages from AEMO's maintenance planning schedules (via MT PASA²²) in combination with typical maintenance schedules for technology types. Units on planned maintenance outages are excluded from the Balancing Merit Order.

Marginal Loss Factors

Transmission losses occur when this electrical energy is transported from generators to the demand centres. Marginal Loss Factors (MLF) apportion the cost of these losses across all participants in the market. They are a scaling factor, normally in the range of 0.9 to 1.1,

Volume weighted loss factors are applied to every generator unit on the WEM based on Western Power's most recent calculation of loss factors²³ for 2018-19. A static loss factor is applied in each trading interval within the study period and applied to generator bidding profiles to determine offers referred to the regional reference node.

The regional reference node in the WEM model is set at the Muja 330 kV busbar²⁴.

Auxiliary factors

Auxiliary factors account for station auxiliary loads and are used to calculate as-generated values based on sent-out generator values, or vice-versa.

2.2.2 Demand modelling

Inter-temporal and inter-spatial (regional) electricity consumption behaviour is maintained in the forecast. Historical half-hourly operational grid demand 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.

²² Scheduled outages are submitted to AEMO for use in their projected assessment of system adequacy assessments for short-term and medium-term timeframes. MT PASA refers to this assessment for the medium term horizon, which is a three year assessment.

²³ [2018-19 loss factor report](#)

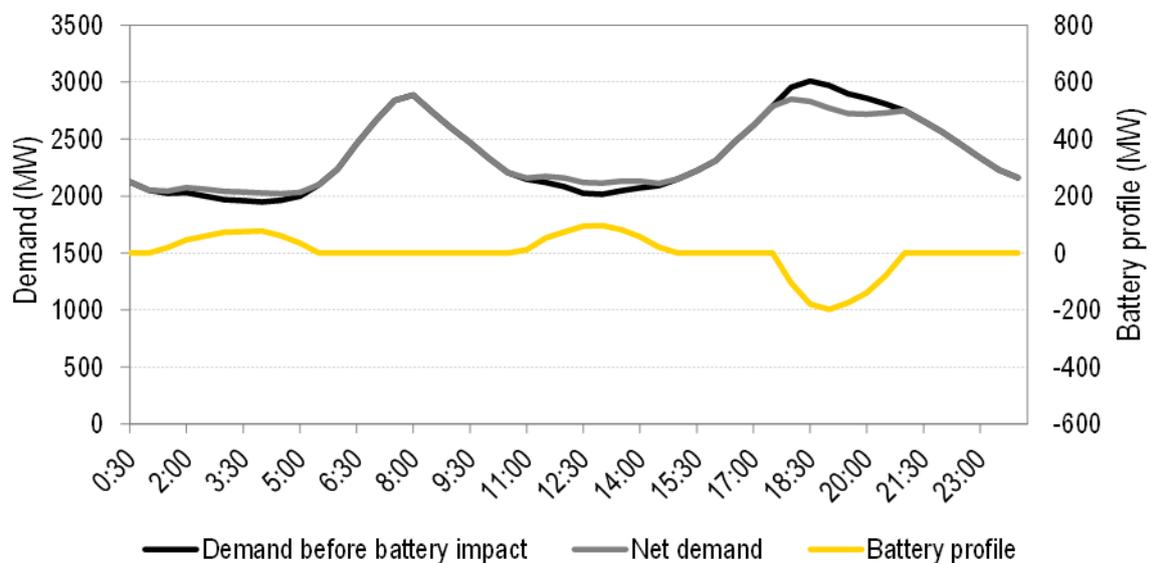
²⁴ Recent reforms have discussed a move of the regional reference node to a demand centre. However, the timing of this change is not expected to occur within the timeframe being considered for this study.

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 based on information provided in AEMO's ESOO. Behind the meter 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. 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. Figure 3 below illustrates an example day in winter on how the aggregate battery charge and discharge cycle alters the operational demand profile.

Figure 3: Example day showing impact of behind-the-meter battery storage on operational demand in the WEM



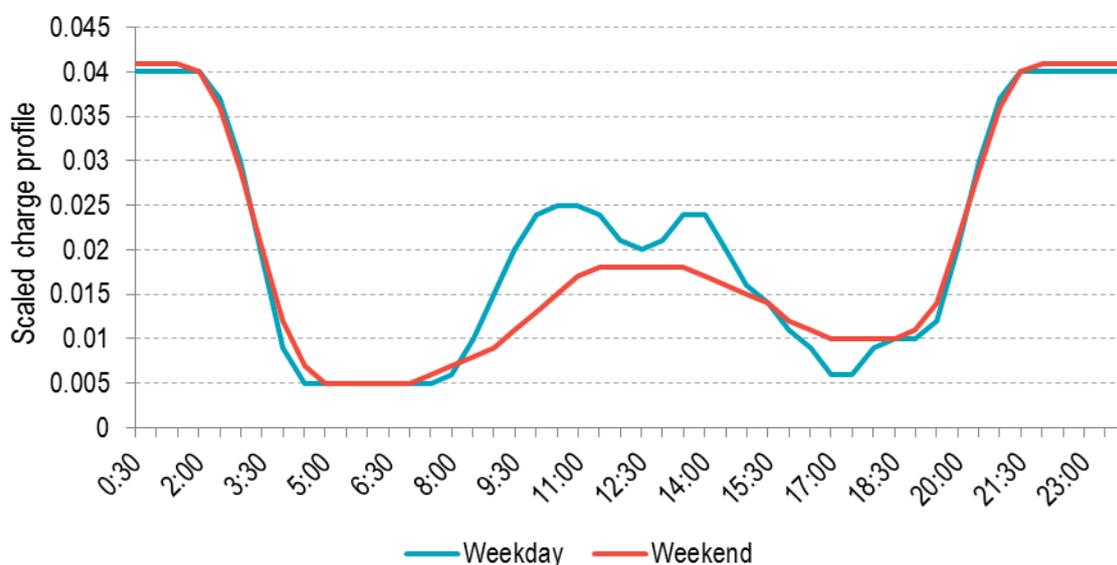
This behind-the-meter storage profile is added/subtracted to the operational demand for 2-4-C[®] modelling. EY uses the same assumptions as AEMO, including that behind-the-meter battery storage has a negligible contribution to peak demand. Accordingly, the energy and peak-demand contributions of the 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 2018 WEM ESOO demand scenarios.

Electric Vehicles

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[®]. 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 4 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 4: Percentage of daily energy use for EVs in each half-hour of the day



2.2.3 Network capability

EY can model power transfer limits and network limitations that constrain the physical dispatch of generator units and dispatchable loads. In actual market dispatch and 2-4-C®, these are typically used in the form of a network constraint equations²⁵. However, the WEM is currently dispatched without network constraint equations and is occasionally dispatched subject to network constraints when there are contingencies such as multiple transmission line outages.

In this Project the forward-looking modelling is conducted without assuming any contingencies occur and as such is dispatched without any network constraint equations²⁶. That is, the network is assumed to be in a system normal operating state with no prior network outages.

Voltage, transient and other constraints related to the dynamic stability of the network are also excluded in this assessment. Similarly, the operation of the power system in islands is not modelled requiring dispatch outside of the Balancing Merit Order is not modelled.

2.2.4 Renewable generation modelling

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 data²⁷ from the Bureau of Meteorology (BOM) on a 12 km grid across Australia to develop wind

²⁵ 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.

²⁶ EY’s modelling of constrained access for the Public Utilities Office found that the frequency of constraints binding is negligible with network constraint equations based on 800 MW of GIA-connected new entrant renewable capacity. It is therefore unlikely to have a materially impact on the scope of this study.

²⁷ An historical hourly profile is comprised of many historical hourly forecasts made every six hours by the BOM throughout the historical years modelled.

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.

- **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.

2.3 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 can be 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 case will simulate 50 Monte Carlo iterations of generator outages for the study period, for each demand modelled. For this Project, EY will model two reference years for atmospheric conditions and load shape for the 50% POE demand forecast.

The 50% POE demand forecast represents AEMO's expected outcomes for the study period.

Table 4 provides a summary of key simulation parameters.

Table 4: Simulation parameters

Simulation parameter	Description
Demand profiles	For each future simulation year the 50% POE values for each forecast year will be modelled in a half-hourly time sequential series.
Reference years	Two reference years will be modelled. Different reference years will have variability in terms of the half-hourly demand, wind and solar profiles according to the weather patterns in those years.
Monte Carlo iterations	On the demand profile we will model 50 Monte Carlo iterations ²⁸ of thermal generator outages (full and partial unplanned outages).

²⁸ 50 iterations of Monte Carlo simulations produces converged dispatch outcomes suitable for the purposes of the modelling

Simulation parameter	Description
Results	All results will be provided as a weighted average over all 50 iterations. These iterations are made up of two reference years with a single demand profile with 50 Monte Carlo iterations of forced outage profiles (as described above).

2.4 Key data used in calculation of market parameters

Table 5 provides a summary of the key data metrics that EY may use in delivering this Service. Each of these metrics can be reported on a half-hourly basis for each forward-looking financial year in the relevant study year or aggregated as appropriate.

Table 5: Key data metrics used for calculating market parameters

Simulation outputs	Parameter
Balancing Price (\$/MWh)	Required for Margin Value calculations as per Ancillary Service Settlement Calculation formula, clause 9.9.2(f) of Rules.
MW dispatched in each half-hourly period from each generation facility	SRAS requires consideration of the highest total MW output of generation units synchronised to the SWIS.
MW dispatched across Synergy Balancing Portfolio	Synergy's total generation is an outcome of the simulation modelling based on dispatch outcomes.
Total cost across Synergy Balancing Portfolio	Synergy's total generation costs are a function of fuel costs, heat rates, generation output and VOM. This is calculated based on MW dispatch for each individual Synergy generator in the portfolio and aggregated.
SWIS demand ramp rate in a 30 minute period, multiplied by 0.5 ²⁹ to calculate ramp rate in a 15 minute period	SRAS requires consideration of the maximum load ramp expected over a period of 15 minutes.

²⁹ The load demand trace will be produced on a half hourly basis, whilst the Rules requires analysis of 15 minute ramping.

3. Backcasting

As part of the Project, EY performed a backcast of its half-hourly modelling of the WEM. The objective of the backcast is to devise suitable bidding profiles for each generator to emulate their dispatch patterns in an historical year. These bidding 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 backcast 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 backcast exercise 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 backcasting task is used to approximate the typical operating and fuel parameters for each generator with up to four bidding profiles, applying to different time periods³⁰.

Some generators are easier to model than others, where they exhibit more consistent dispatch levels relative to the Balancing Price. The backcasting 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.

This section describes the input data used for the backcasting exercise of 2017-18, and the approach taken along with the backcasting outcomes.

The backcasting exercise was performed on the 2017-18 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.

3.1 Backcasting inputs and assumptions

Table 6 summarises the input data and sources used in the backcasting exercise.

Table 6: Summary of input data used for the backcasting exercise

Input data	Source	How input data is used in backcast simulation
Generator list	http://data.wa.aemo.com.au/#facility-scada	To ensure each physical generation facility is modelled
2017-18 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.
2017-18 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 in the forward-looking modelling we set their available half-hourly generation at the historical levels rather than rely only bids for their dispatch.

³⁰ The time periods used for some generators are summer-peak, summer-off-peak, winter-peak and winter-off-peak.

Input data	Source	How input data is used in backcast simulation
2017-18 STEM balancing market half-hourly prices	http://data.wa.aemo.com.au/#balancing-summary	Bidding profiles for each generator were developed by analysing the relationship between half-hourly historical balancing prices and generation.
2017-18 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 backcasting exercise.
2017-18 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 bids before being used in dispatch as they are in the actual market.
2017-18 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 backcast run for 2017-18, in line with the two price caps which apply in the WEM: <ul style="list-style-type: none"> - The Maximum Short Term Energy Market (STEM) Price which applies when non- liquid fuel is used by the highest cost peaking plant. For the 2017-18 backcast year this was \$351/MWh. - The Alternative Maximum STEM Price, which applies when liquid fuel is required to be used. For the 2017-18 backcast year this was \$604/MWh³¹. 	The alternative maximum price is set as the maximum Balancing 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.

3.1.1 Modelled generators

When determining which facilities to model in the backcast and forward-looking simulations, EY has considered the set of facilities³² with SCADA data available.

Backcast of the model could only be conducted where there was historical dispatch available to replicate. We also cross-checked this set against the list of registered facilities³³ the generators included in the backcast and forward-looking simulations are listed in Table 7.

The table also notes how we modelled the availability of each generator in each trading interval for the backcasting exercise the availability profile of each generator is defined as the maximum capacity³⁴ less any reported outage³⁵.

- ▶ **Using historical generation:** A number of generators were 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 bid a static value between -\$50/MWh and \$0/MWh reflecting their short run marginal cost and external Large-scale Generation Certificate (LGC) revenue. We do note however that a number of renewable facilities have Balancing Submissions at the floor price.

³¹ We note that the actual Alternative Maximum STEM Price is revised on a monthly basis.

³² <http://data.wa.aemo.com.au/#facility-scada>

³³ <http://data.wa.aemo.com.au/#participants>

³⁴ Maximum capacity as provided in <http://data.wa.aemo.com.au/#facilities>

³⁵ <http://data.wa.aemo.com.au/#outages>

- ▶ It also applies to retiring thermal units as they are not modelled the forecast³⁶.
- ▶ **Bids:** A set of up to four bidding profiles are used in 2-4-C[®] when creating a Balancing Merit Order to determine generation dispatch in the Balancing Market in each trading interval. Four bidding 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 bidding profiles are the ultimate output of the backcast process for use in the forward-looking simulations.

Table 7: List of generator units included in the backcast

Generator	Availability profile ³⁷
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
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

³⁶ 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. It is assumed that these do not operate under normal operating conditions.

³⁷ Capacity defined in this table is the maximum capacity as defined in <http://data.wa.aemo.com.au/#facilities>

Generator	Availability profile ³⁷
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

3.1.2 Outages

Generator outage data is modelled so that 2-4-C[®] excludes a generator from the Balancing Merit Order if it is on full outage and caps its output if it is on partial outage, based on an availability profile.

There are likely to have been network outages in 2017-18 that impact on generation dispatch outcomes. We assume these are captured in the 'consequential' outages reported in the AEMO WA outage data and are therefore treated like other recorded outages³⁸.

Any unrecorded outages will be reflected in the bid 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.

3.2 Backcast simulation approach

The objective of the backcast is to tune the model to reproduce historical market outcomes using a set of up to four generator bidding profiles for each generator. A bidding profile can have up to ten price-quantity pairs. For example, a bidding 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 backcast can be summarised as follows:

- ▶ Set up 2-4-C[®] to simulate the 2017-18 financial year, using the input data as described earlier.
- ▶ Establish an initial bidding profile for each generator (using the procedure described below).
- ▶ Observe the pricing and dispatch outcomes and modify the bidding profiles accordingly to achieve a closer match to the actual prices and dispatch in the market.
- ▶ Iteratively re-simulate 2017-18 and refine the bidding profiles until the price and generation outcomes are satisfactory.

3.3 Bidding profile development

Generator bidding profile development is based on an expected SRMC approach. 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 Balancing Submissions as frequently as from one trading interval to the next as well as bid capacity in multiple bid bands. Data on the mechanisms for these bid changes are largely confidential, and are difficult to predict in the

³⁸ <http://data.wa.aemo.com.au/#outages>

future. As such, EY constructs bidding profiles for 2-4-C[®] to represent the typical bidding behaviour of different types of generators, as follows:

- ▶ **Baseload generators:** These are generators with a must-run component³⁹, 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.
- ▶ **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 bid 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 bid all capacity at the alternative maximum price multiplied by the loss factor⁴⁰.
- ▶ **Renewable generators:** Renewable generators are bid in at a static value between -\$50/MWh and \$0/MWh reflecting their short run marginal cost and an assumed LGC revenue as discussed above.

Other important influences on bidding 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 bids 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 pricing⁴¹.

3.4 Results

EY analysed the backcasting 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 market scenarios for the Project.

The relevance of each metric is described in the following:

- ▶ **Annual average:** annual average price and generation and total annual generation provide the simplest overview of backcasting outcomes, demonstrating the average accuracy of the modelling throughout the year.
- ▶ **Peak and off-peak:** given the nature of the Project in calculating parameters associated with peak and off-peak periods, specific emphasis is placed on examining average pricing outcomes for peak periods (defined as the trading intervals between 8:00am to 10:00pm) and off-peak periods.
- ▶ **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

³⁹ 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.

⁴⁰ Bids submitted apply at the generator transmission connection point. They are subsequently divided by the loss factor when referred to the Regional Reference Node (RRN) during dispatch.

⁴¹ Only applicable to Independent Power Producers (IPP). AEMO advises that units providing LFAS within the Synergy Balancing Portfolio are enabled for their entire range.

highlight whether the number of negative prices at different levels is being accurately captured by the model. An accurate price duration curve also indicates an accurate total bid-stack (made up of the bidding profiles from each generator).

- **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.

3.4.1 Price

Table 8 provides a summary of the price outcomes for different time periods. Further detail is provided in sections below.

Table 8: Price outcomes - annual, peak, off-peak

Time period	Actual 2017-18 Price (\$/MWh)	Backcast Price (\$/MWh)	Difference (\$/MWh)
Annual (time-weighted)	53.35	53.16	-0.19
Peak (8:00am to 10:00pm)	60.55	63.67	3.12
Off-Peak (10:00pm to 8:00am)	43.27	38.43	-4.83

The actual annual average price for 2017-18 is \$53.35/MWh whereas the annual average price in the backcast simulation is \$53.16/MWh. With a difference of -\$0.19/MWh (-0.4%), this is considered sufficiently accurate. Figure 5 shows the balancing price duration curve for the backcast compared with the actual balancing prices over the full extent of price outcomes. At this resolution, the backcast looks to be highly accurate.

Figure 6 and Figure 7 present charts for peak and off-peak periods. Results show that during peak periods, prices observed in the backcasting report are \$3.12 higher than historical results whereas during off-peak periods, prices are \$4.83 lower on average.

The differences in price outcomes is due to the static bids being unable to capture daily bid and availability patterns of particular generators, such that the backcast had too much generation available bid at low prices overnight, and not enough generation bid at low prices during some of the peak periods. Based on observations of simulated outcomes during the backcast, it is noted that the dispatch of Cockburn Power Station was particularly sensitive to relatively small changes in bidding profiles which also impacted on the overall Balancing Price outcomes.

Figure 5: Price duration curve for 2017-18 and the benchmark, all prices

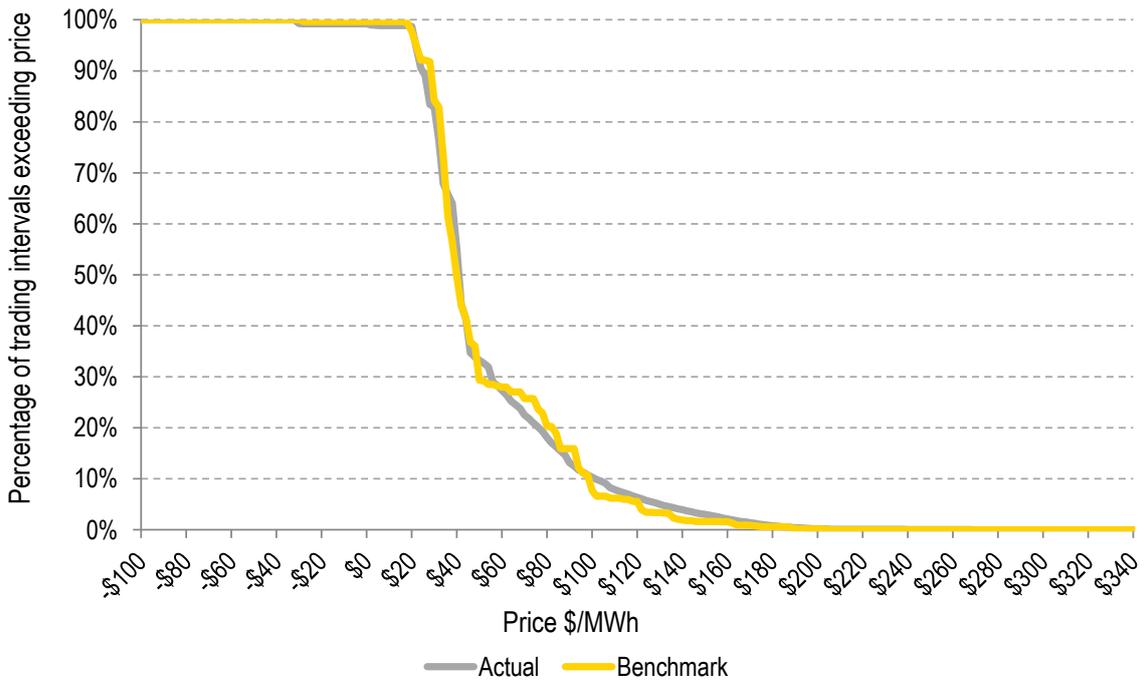


Figure 6: Price duration curve for 2017-18 and the backcast, peak period

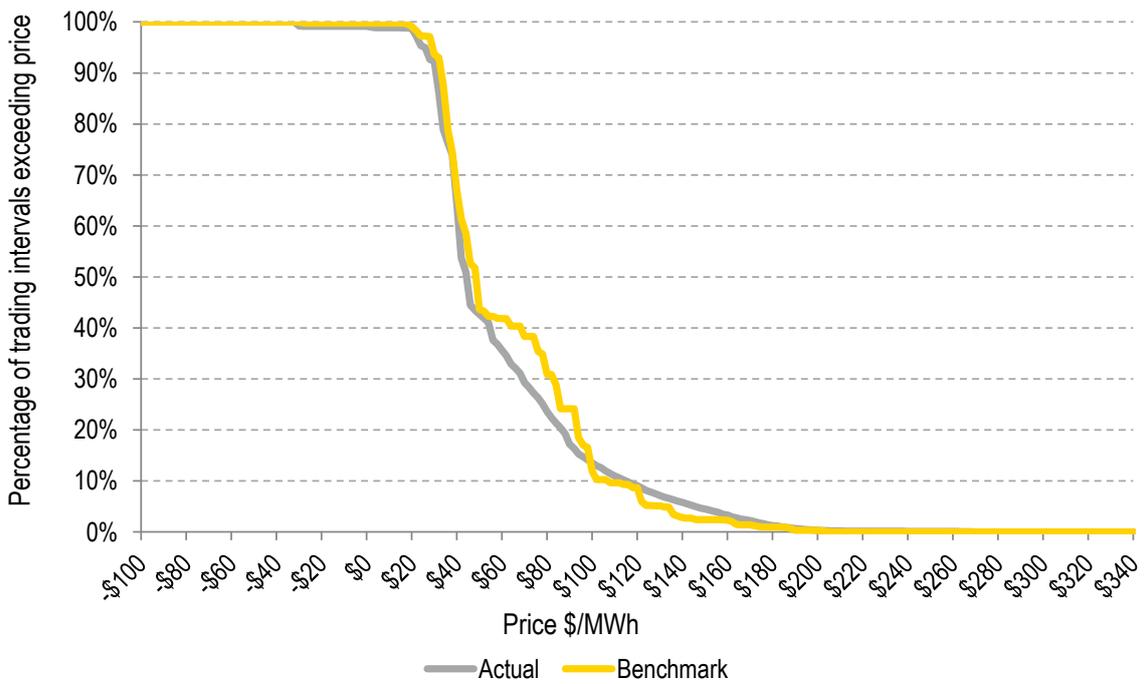


Figure 7: Price duration curve for 2017-18 and the backcast, off-peak period

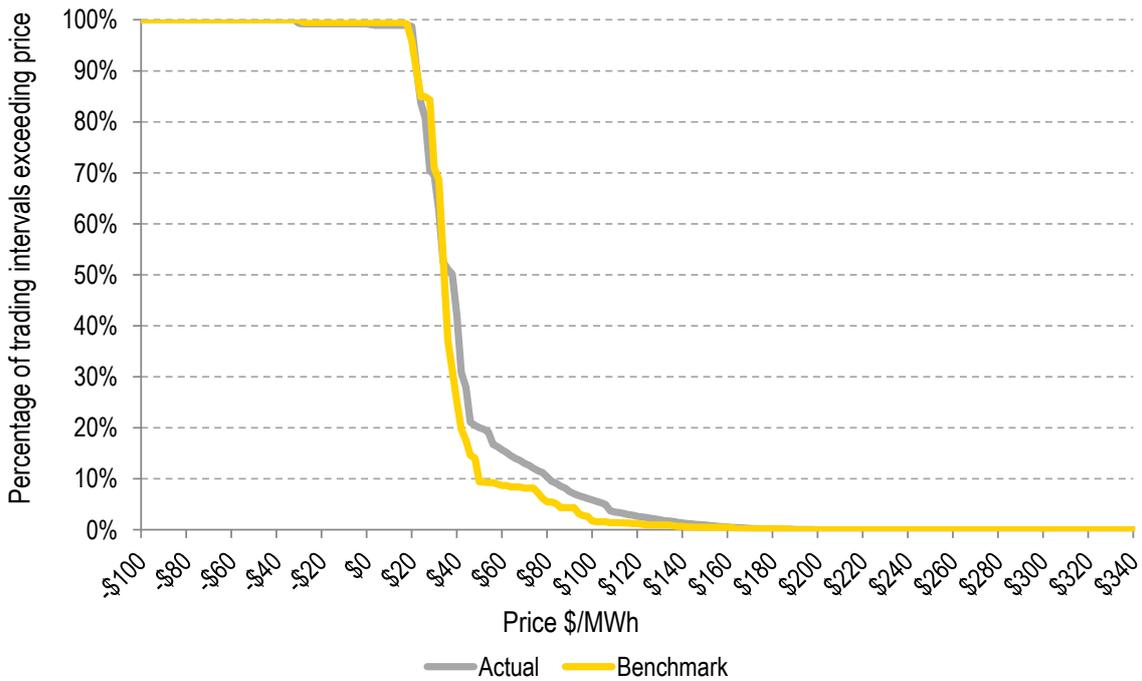
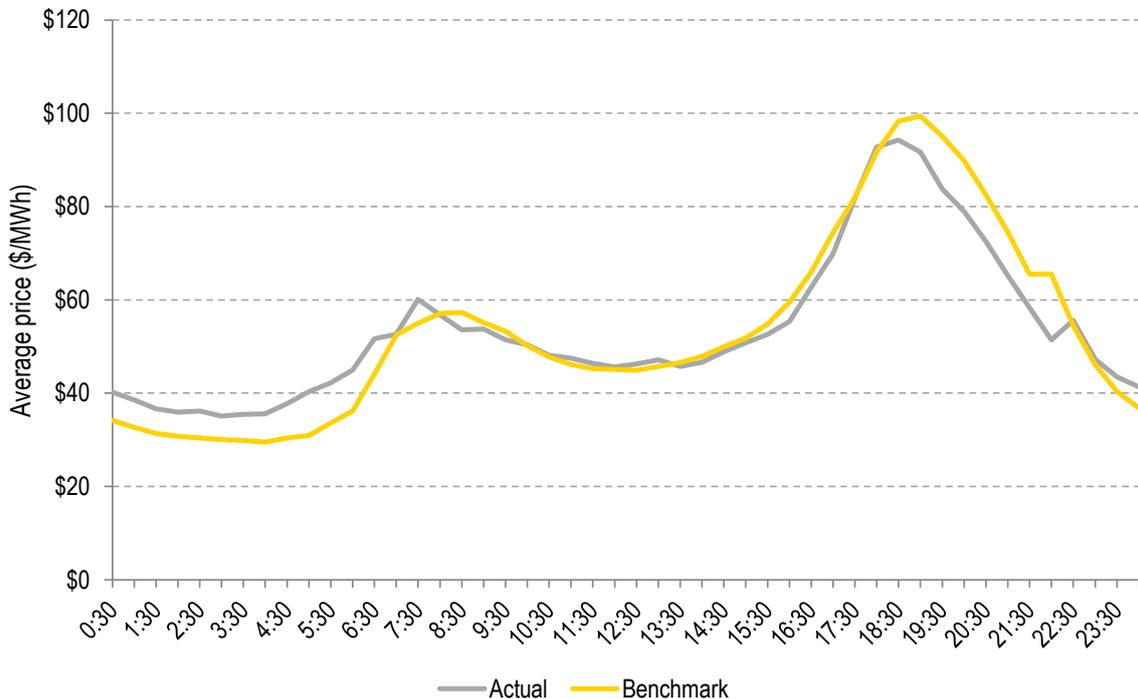


Figure 8 compares the backcast to the actual prices on a time-of-day average basis. The general shape of the time-of-day average profile is modelled relatively well, with the prices being higher overnight, broadly flat during the day following a morning peak, and with the overall peak across the day in the early evening. The average difference across the whole time-of-day profile is low, at around $-\$0.19/\text{MWh}$ (backcast - actual). The backcast prices are on average $\$5/\text{MWh}$ higher than actual from 19:00 to midnight, and on average $\$6/\text{MWh}$ lower from midnight to 06:00. During the day, between 08:00 and 16:00, the average difference is $\$0.40/\text{MWh}$, and over the evening peak (16:00 to 20:00) the difference is around $\$4/\text{MWh}$.

Figure 8: Annual average time-of-day prices comparing actual to the benchmark



3.4.2 Generation duration curves by station

This section presents generation duration curves and time-of-day averages by station, as defined in Table 9, for the units for which backcast bids were developed. In most instances, stations represent individual power stations. The exception is liquid fuel generators. 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 Balancing Portfolio or having a very low capacity factor. Liquid fuel has been aggregated as these generators ran infrequently in 2017-18 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 9: Stations and their operation type

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 9 also shows the 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**, without a must-run component, these may have intervals with zero generation where they have no capacity in merit. Their generation is bid in a price-responsive manner although it is acknowledged that non-price responsive operation may occur for several reasons including fulfilling verification and testing requirements imposed by AEMO to maintain Capacity Credits or as part of routine asset management.
- ▶ **Peaker**, which have a very high SRMC and operate rarely.

- **Cogen special**, containing one cogen generator that operates under variable SRMC states⁴².

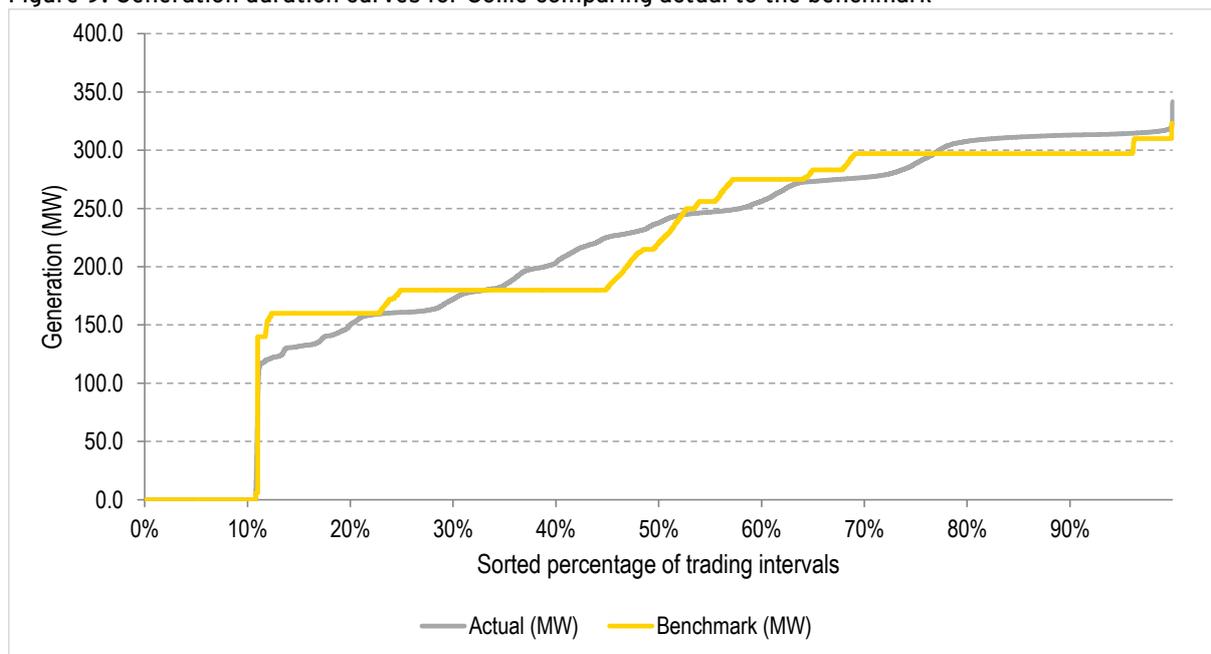
The duration curve and time-of-day average results are shown for selected representative stations for baseload, thermal non-baseload, peaker, and cogeneration operation types in the following sections. All stations are shown in the Appendix.

Collie power station, representing baseload generators

Figure 9 compares the actual and backcast 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 coal fired stations listed in Table 9.

The stepped nature of the simulated dispatch results verses actual results are driven by the discrete number of price quantity pairs used in the simulation verses the range of normal operating dispatch that Collie could operate at (anywhere between its minimum stable operating condition and maximum capacity).

Figure 9: Generation duration curves for Collie comparing actual to the benchmark

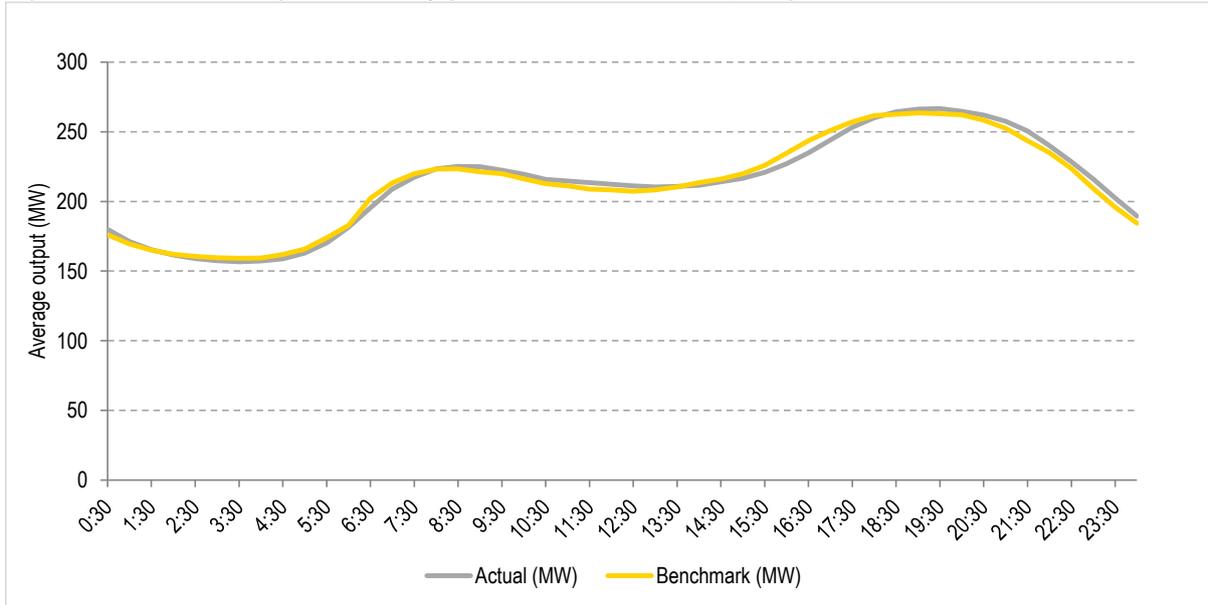


The duration curve is zero for approximately 10% of the trading intervals in the year, representing that Collie was on full outage for that proportion of time in 2017-18. The first positive values are around 130 MW or higher, representing the minimum load (must-run) for Collie's operation. From this point, the duration curve has a smoother slope for the actual 2017-18 data than the backcast 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 2017-18 data is a general result for all generators changing their bid profiles changing throughout the year. EY considers this to be an expected and acceptable result for the benchmark.

Figure 10 shows the annual average time-of-day generation for Collie, highlighting that on average, the backcast 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.

⁴² The other cogeneration stations operate in a more consistent baseload fashion and are allocated to the baseload category.

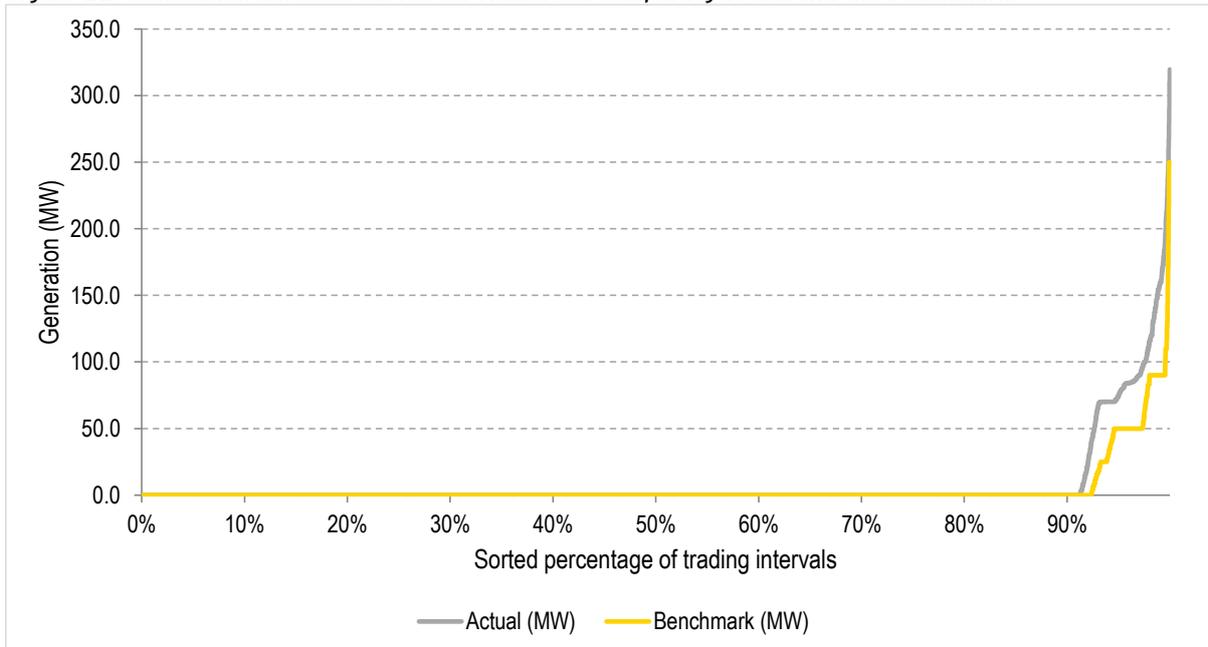
Figure 10: Annual average time-of-day generation for Collie comparing actual and the benchmark



Kemerton, representing thermal non-baseload generators

Kemerton is one of the facilities in the WEM that is fuelled by natural gas with open-cycle technology. Figure 11 compares the actual and backcast generation for Kemerton power station (both units) using the duration curve over all trading intervals in the year.

Figure 11: Generation duration curves for Kemerton comparing actual and the benchmark

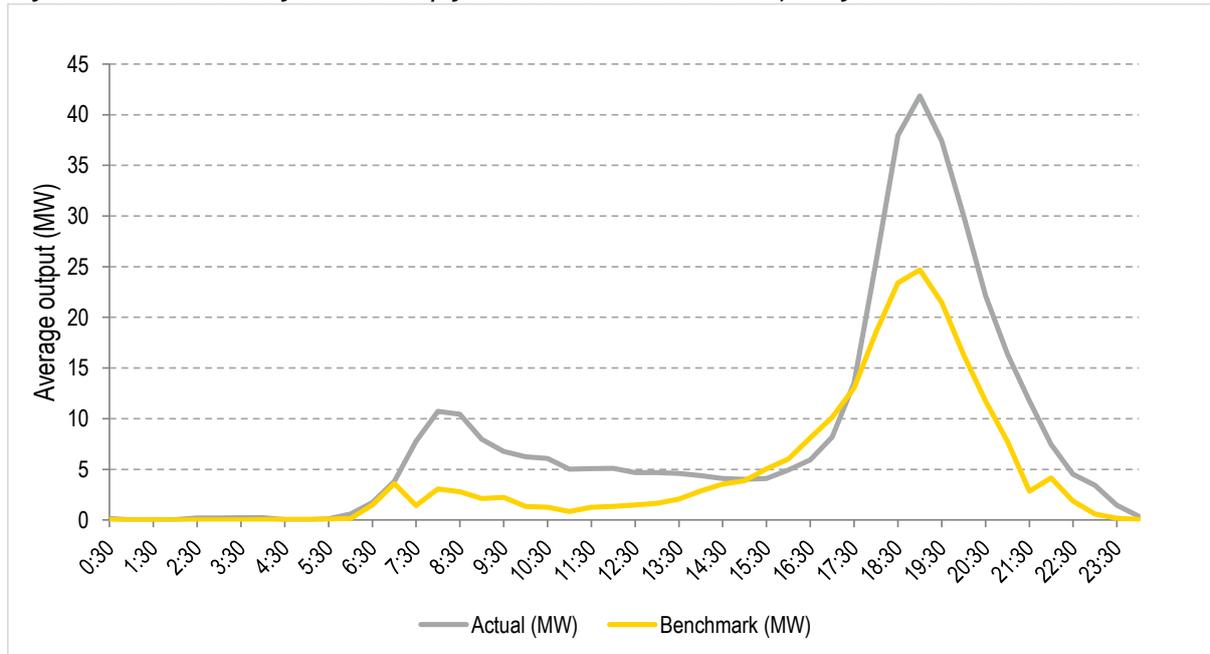


In the backcast, there are slightly more trading intervals with generation below 60 MW and generation above 60 MW in actual outcomes. While the backcast does not achieve the level of maximum generation over the year, these stations operate at or near their maximum for so few intervals in the year that it is difficult to target these specific intervals without resulting in significant over-generation over the rest of the year⁴³. Figure 12 shows that the modelled annual average time-of-day generation generally follows a similar pattern to the historical trend. Also,

⁴³ For example, Kemerton was found to generate within 30% of its maximum historical generation in only 2% of intervals over the 2017-18 year.

historical dispatch at maximum output could be the result of testing of plant or for the purposes of reserve capacity certification rather than Balancing Submissions.

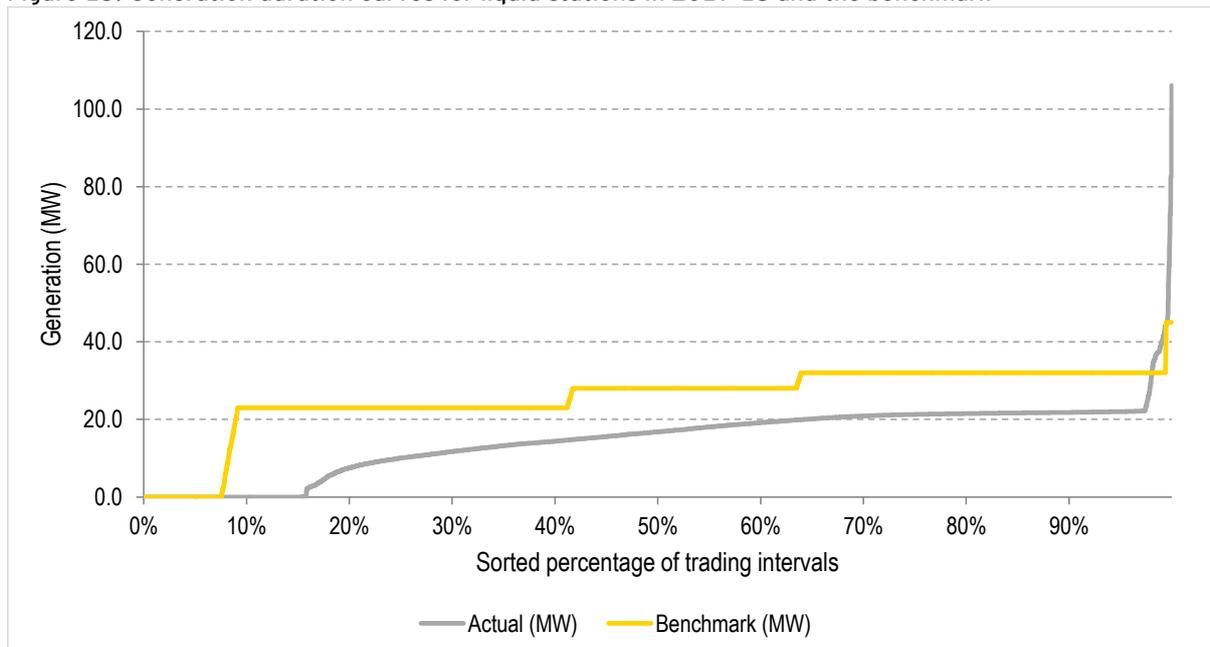
Figure 12: Annual average time-of-day generation for Kemerton comparing actual and the benchmark



Liquid station, representing peakers

Figure 13 compares the actual and backcast generation for the liquid stations using the duration curve over all trading intervals in the year.

Figure 13: Generation duration curves for liquid stations in 2017-18 and the benchmark



There is a difference between the maximum generation achieved in the backcast 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. An example of this is where facilities undergo testing to demonstrate model validation or for the purposes of a Reserve Capacity Test.

Alinta Pinjarra, Unit 1 representing cogeneration

With the exception of Alcoa Wagerup Cogen, cogeneration units (ALINTA_PNJ_U1, ALINTA_PNJ_U2, PPP_KCP_EG1, 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 coal⁴⁴.

Figure 14 compares the actual and backcast generation for Alinta Pinjarra Unit 1 using the duration curve over all trading intervals in the year. Whilst backcast achieves the same total generation over the year as Alinta Pinjarra Unit 1 achieved in 2017-18, 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 14: Generation duration curves for Alinta Pinjarra Unit 1 comparing actual and the benchmark

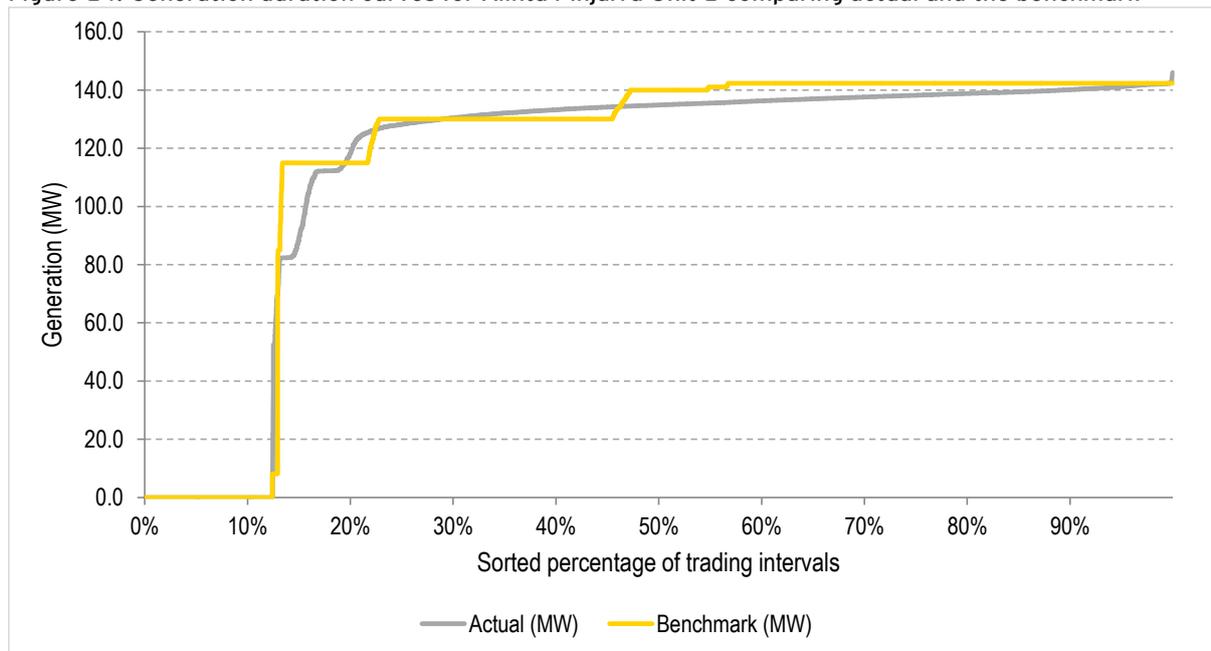
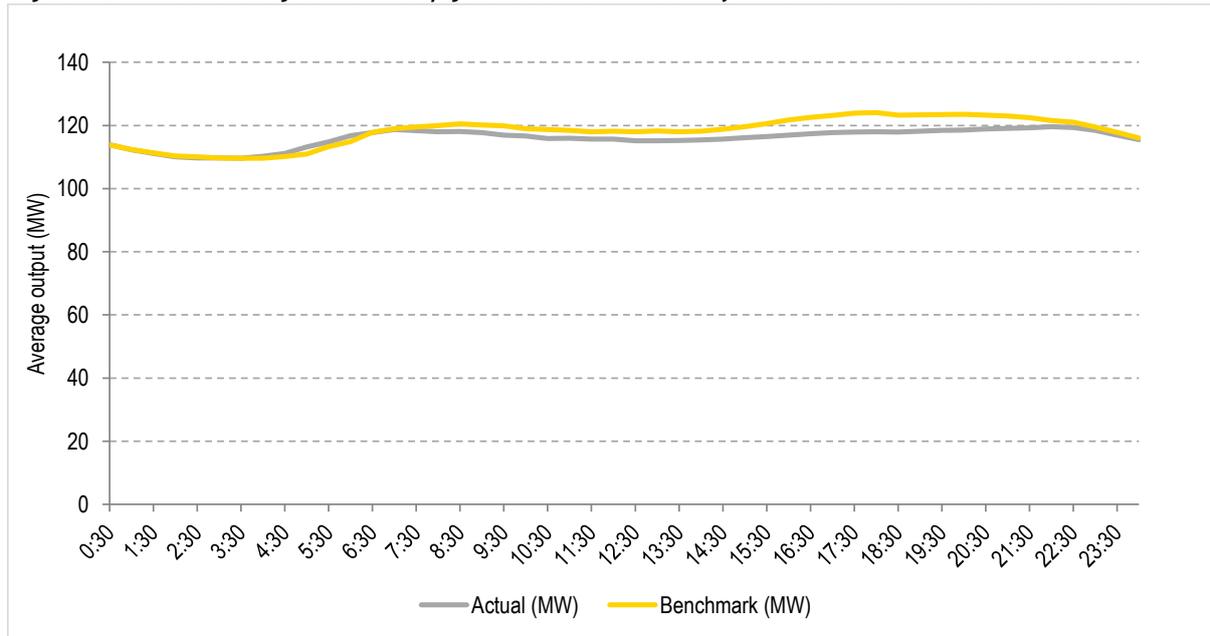


Figure 15 shows that in terms of the annual average time-of-day generation, the backcast follows a broadly similar pattern over the course of the day, with slightly more generation in the evening before midnight, and slightly less thereafter, until around 06:30.

⁴⁴ 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 publicly available on the operating strategy and it generated 110 GWh in 2017-18 which equates to 0.6% of all annual energy modelled. As a result, we followed the same bid profile development approach as for the other generators but focussed on achieving an acceptable level of annual energy.

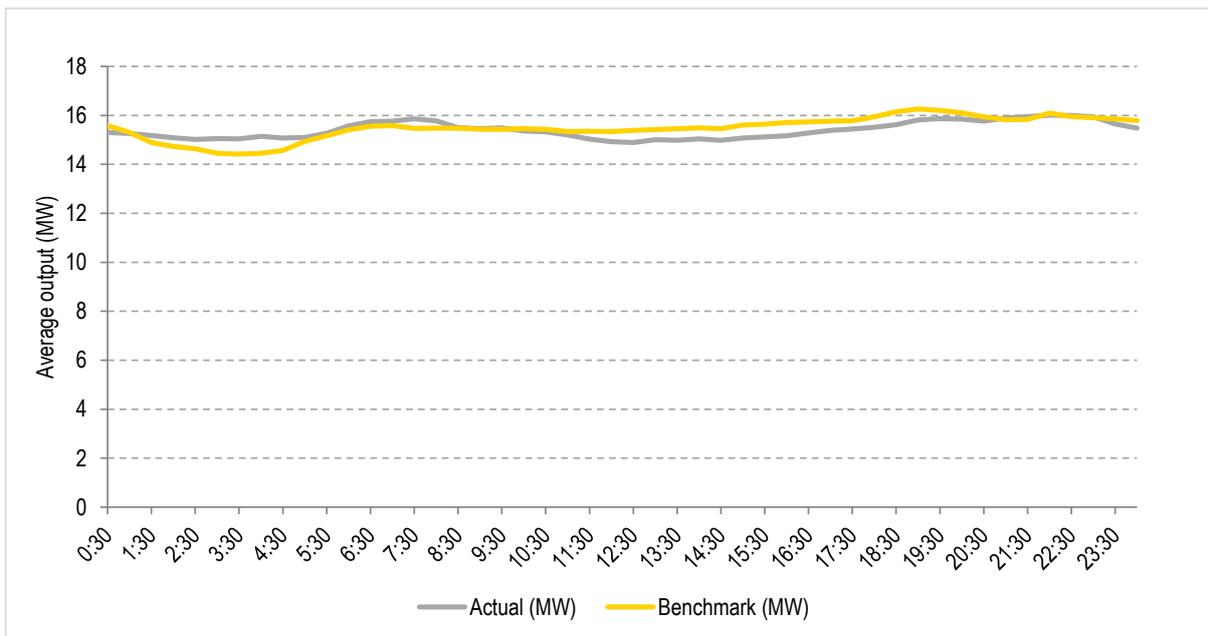
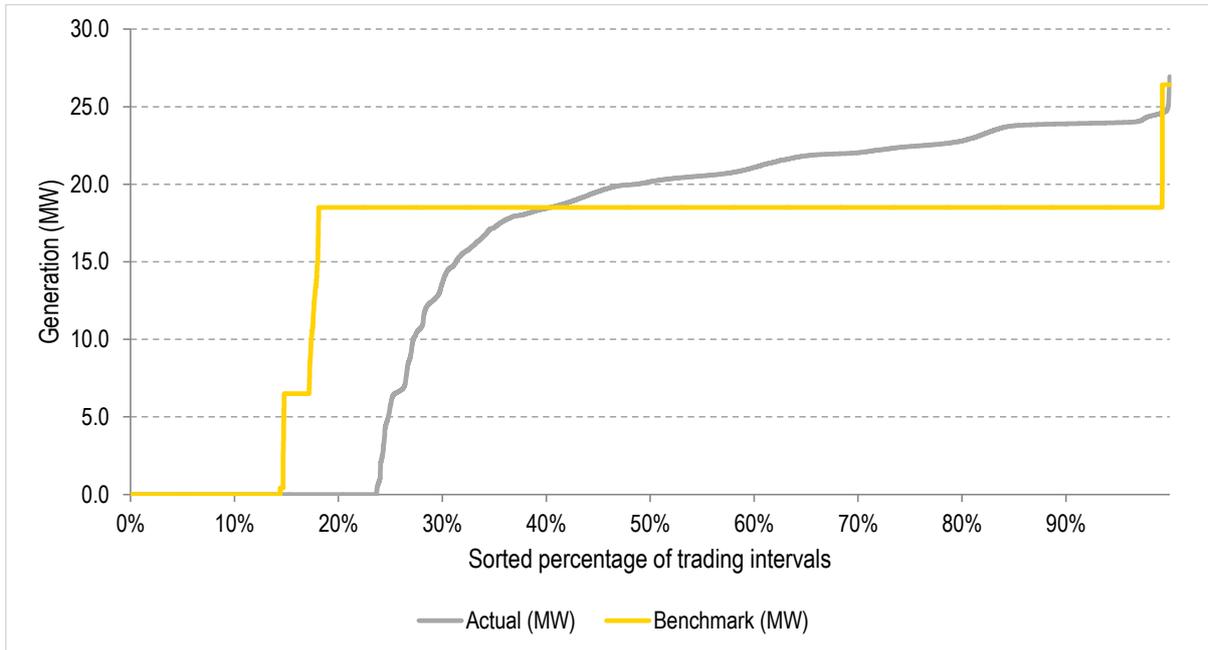
Figure 15: Annual average time-of-day generation for Alinta Pinjarra Unit 1 in 2017-18 and the benchmark



Appendix A Generation duration curves and time of day profiles by station

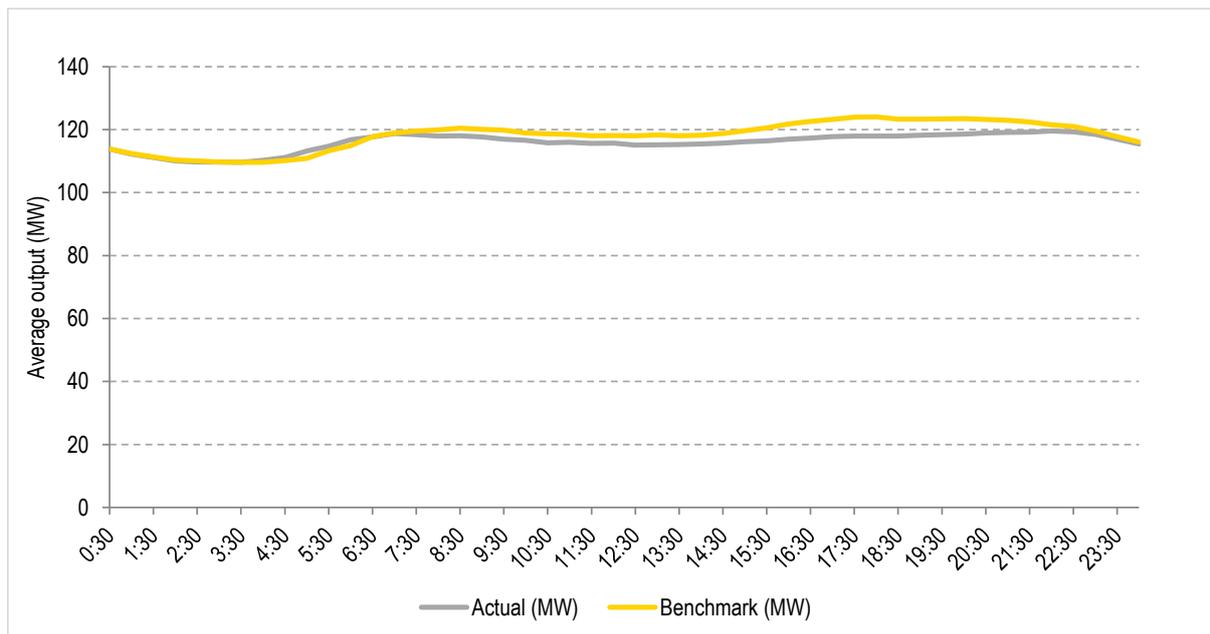
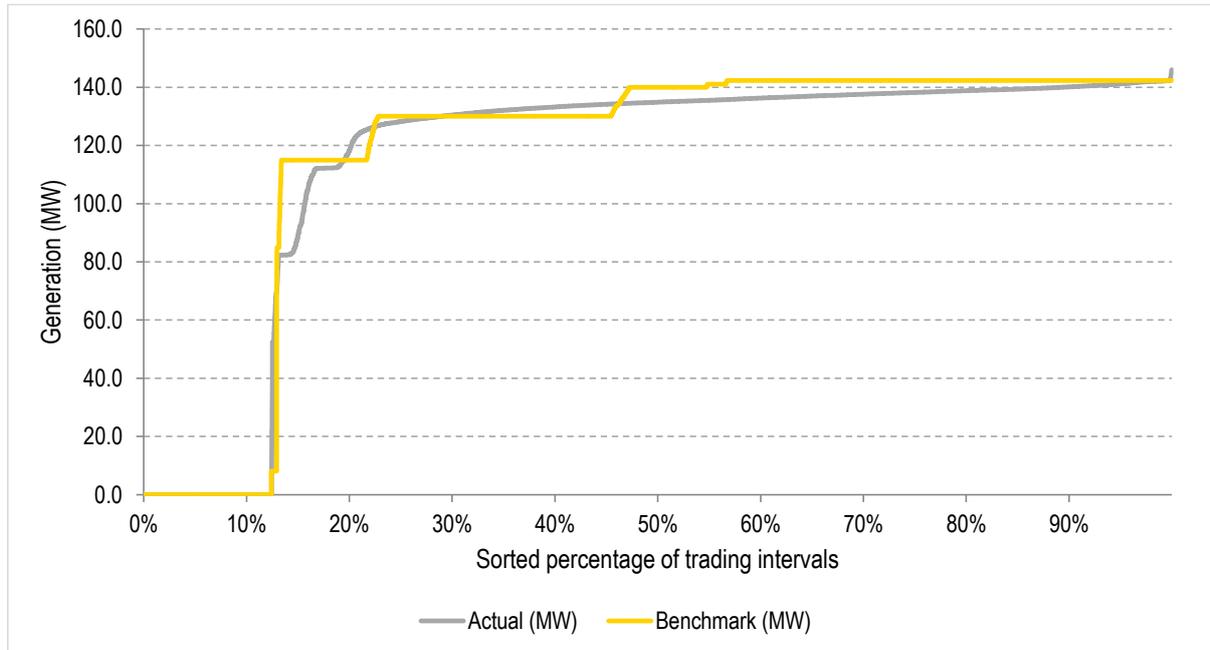
Station name: Alcoa Wagerup

Units included: ALCOA_WGP



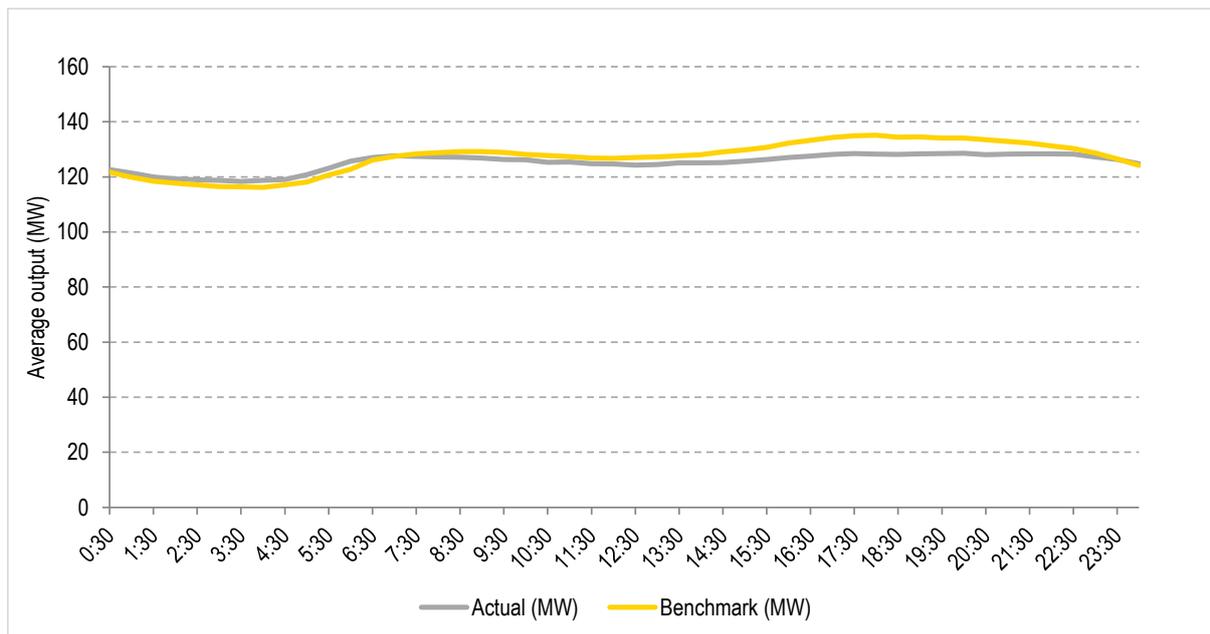
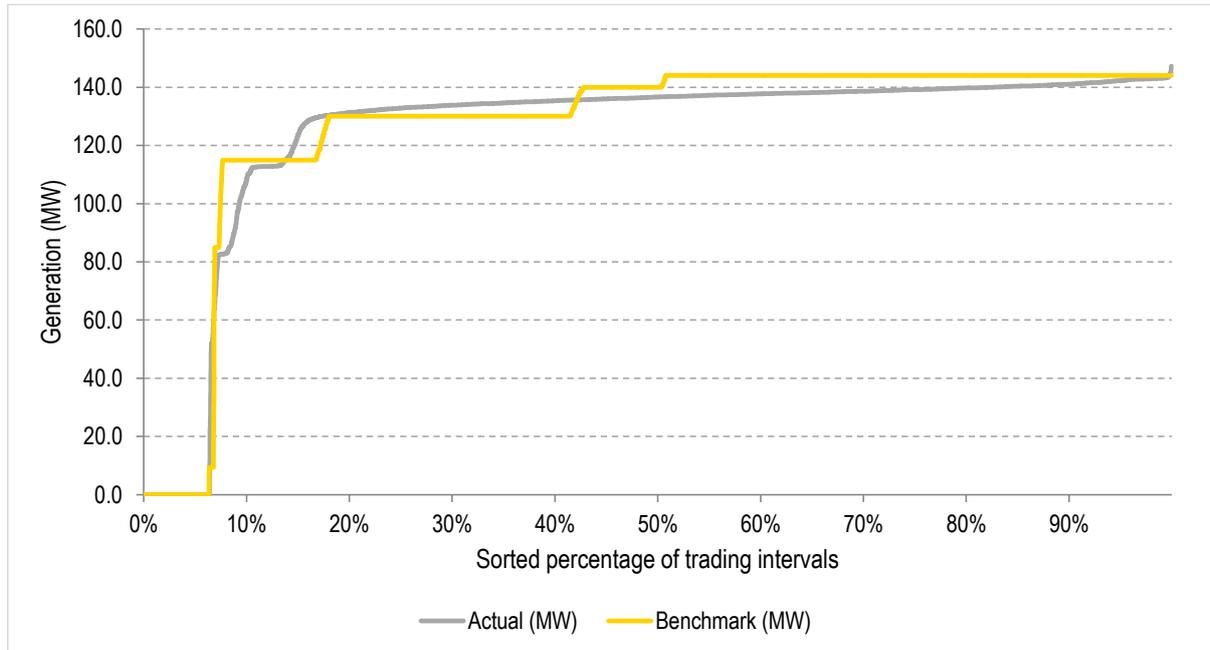
Station name: Alinta Pinjarra 1

Units included: ALINTA_PNJ_U1



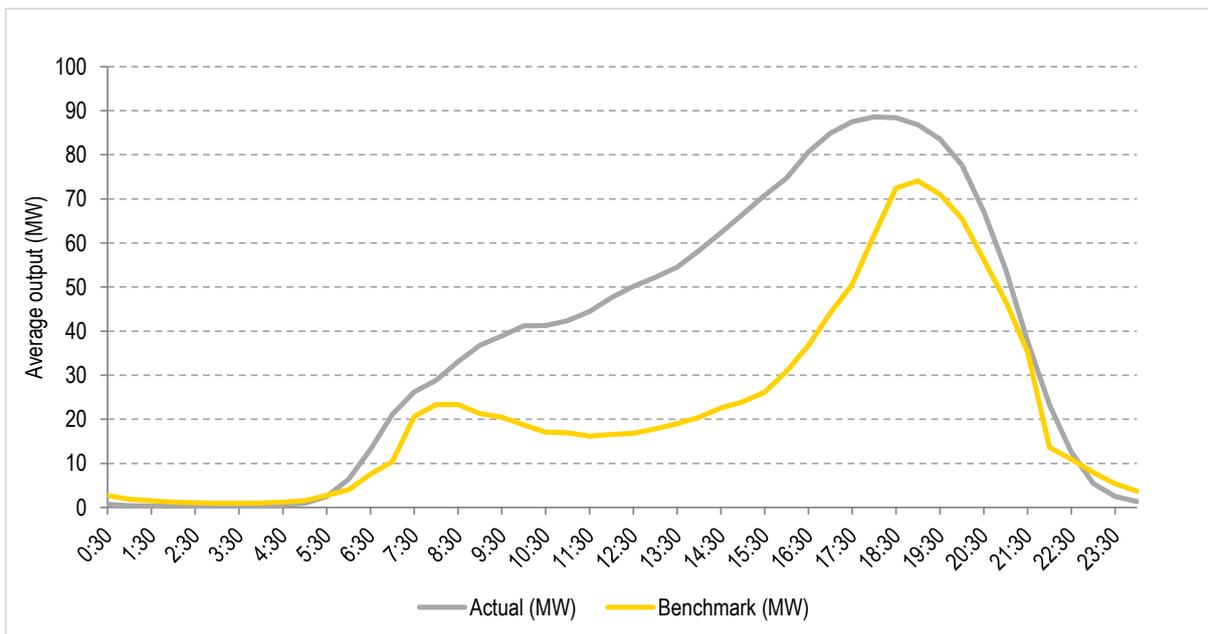
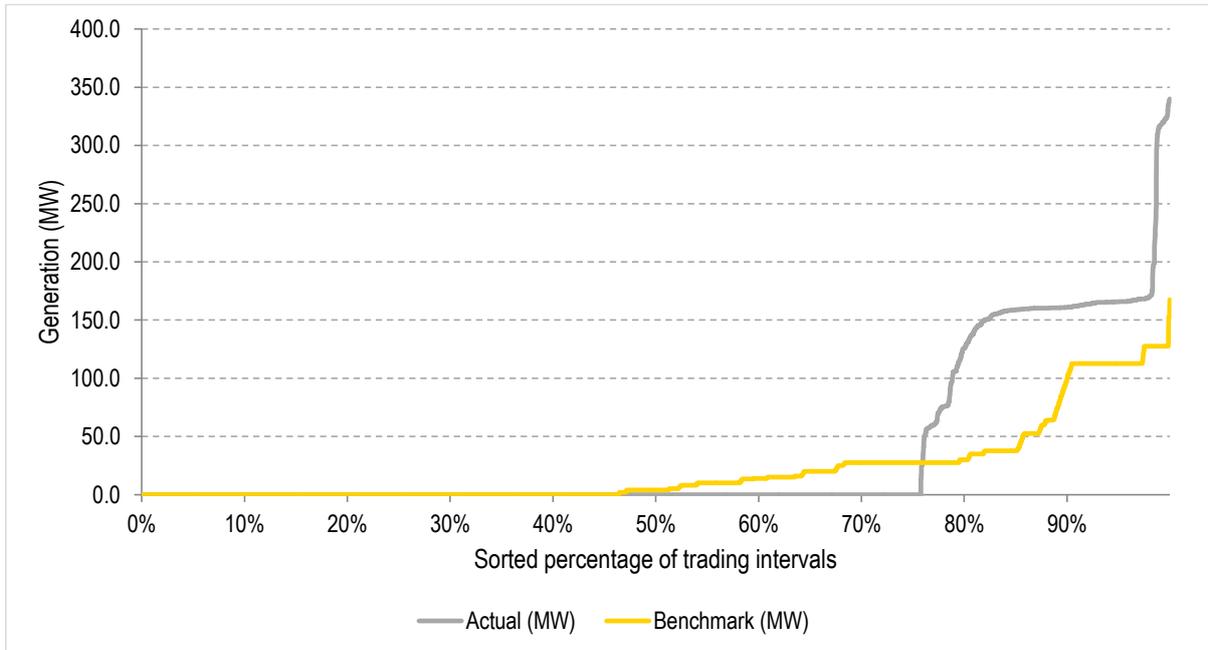
Station name: Alinta Pinjarra 2

Units included: ALINTA_PNJ_U2



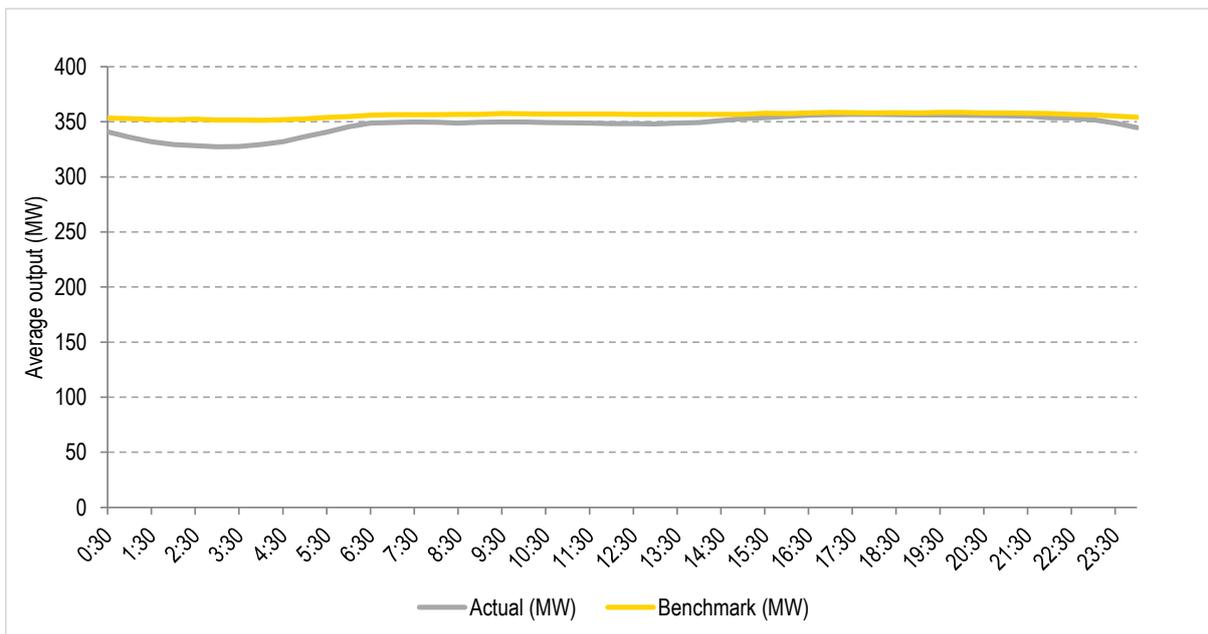
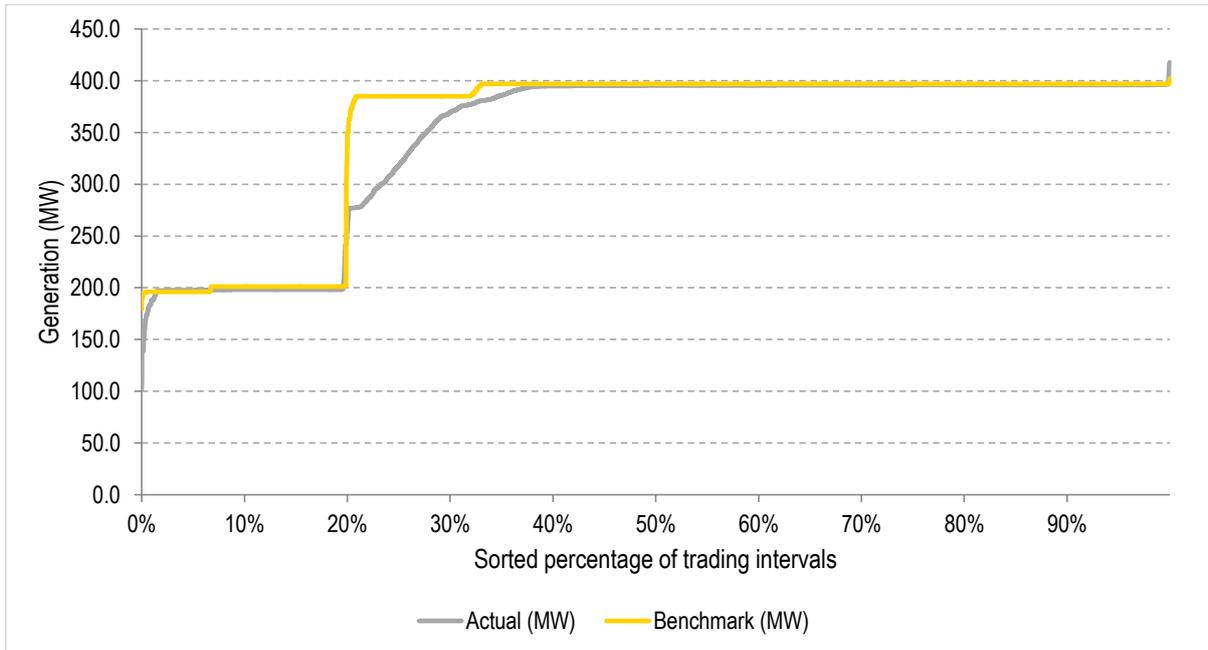
Station name: Alinta Wagerup

Units included: ALINTA_WGP_GT; ALINTA_WGP_U2



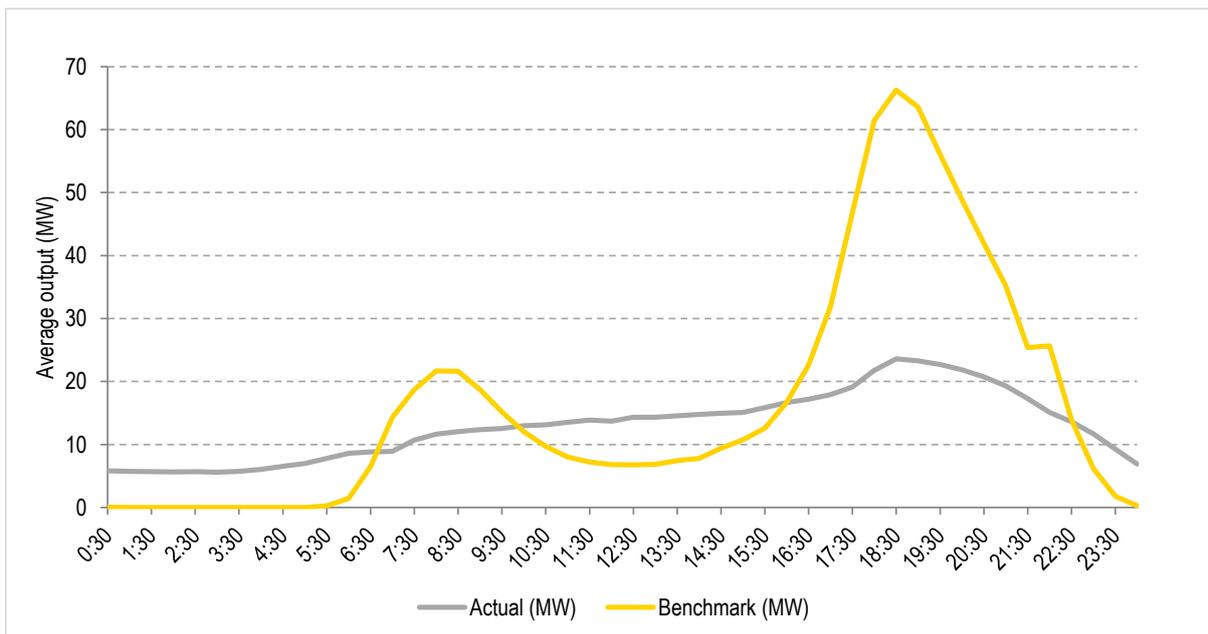
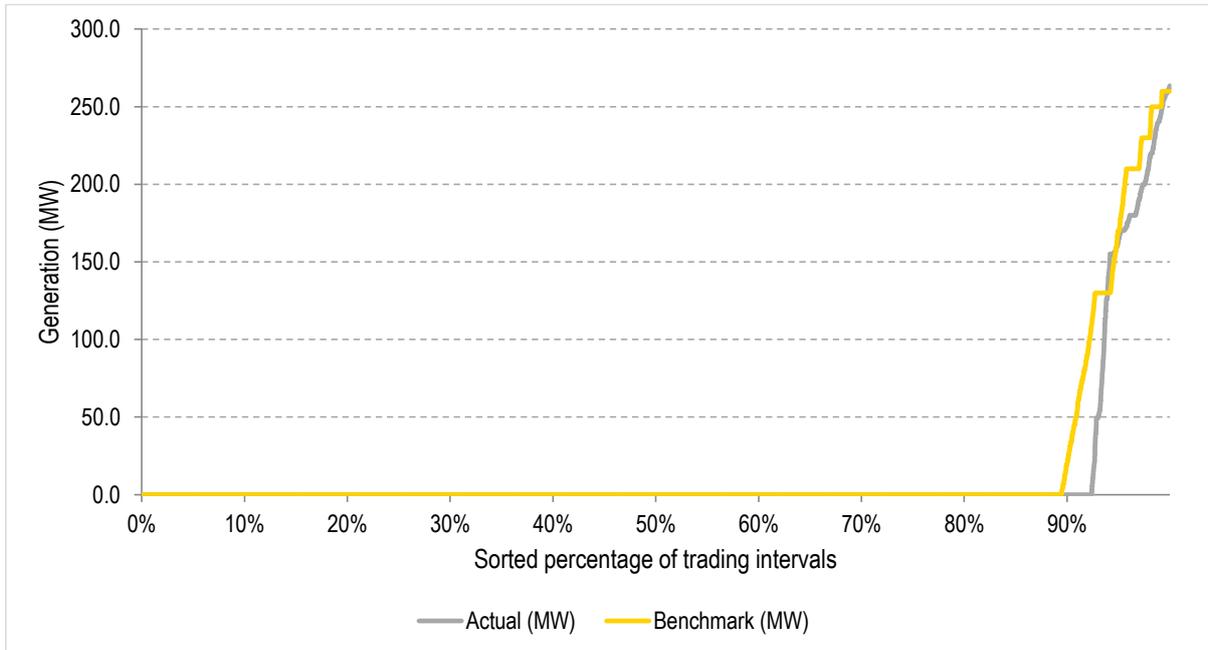
Station name: Bluewaters Power Station

Units included: BW2_BLUEWATERS_G1; BW1_BLUEWATERS_G2)



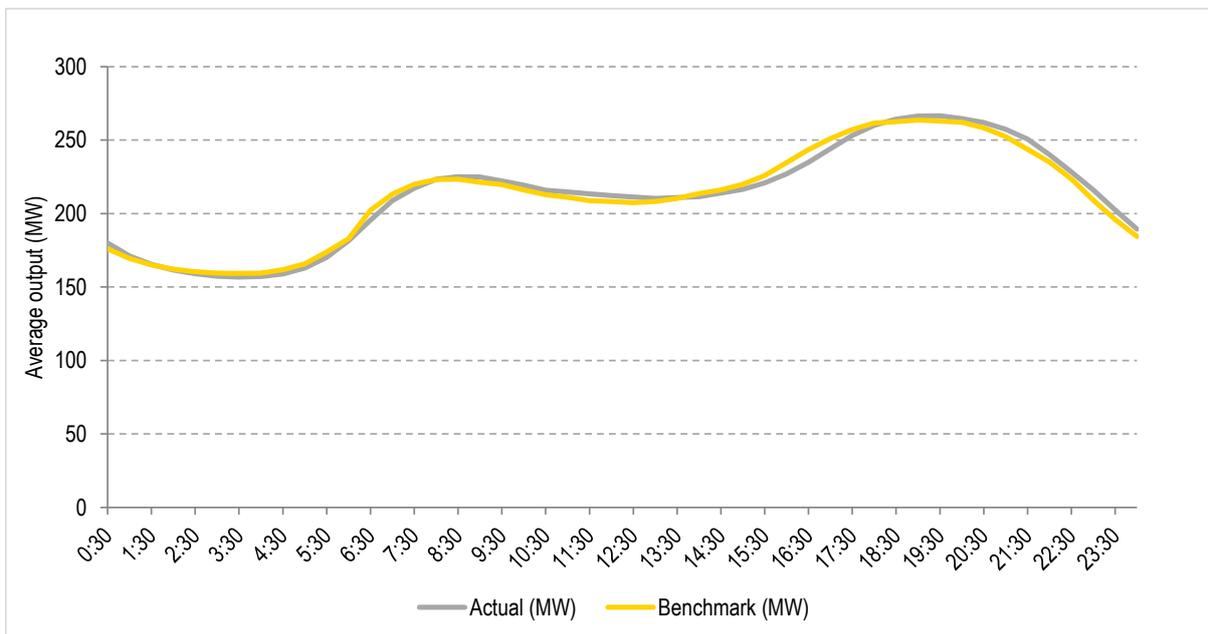
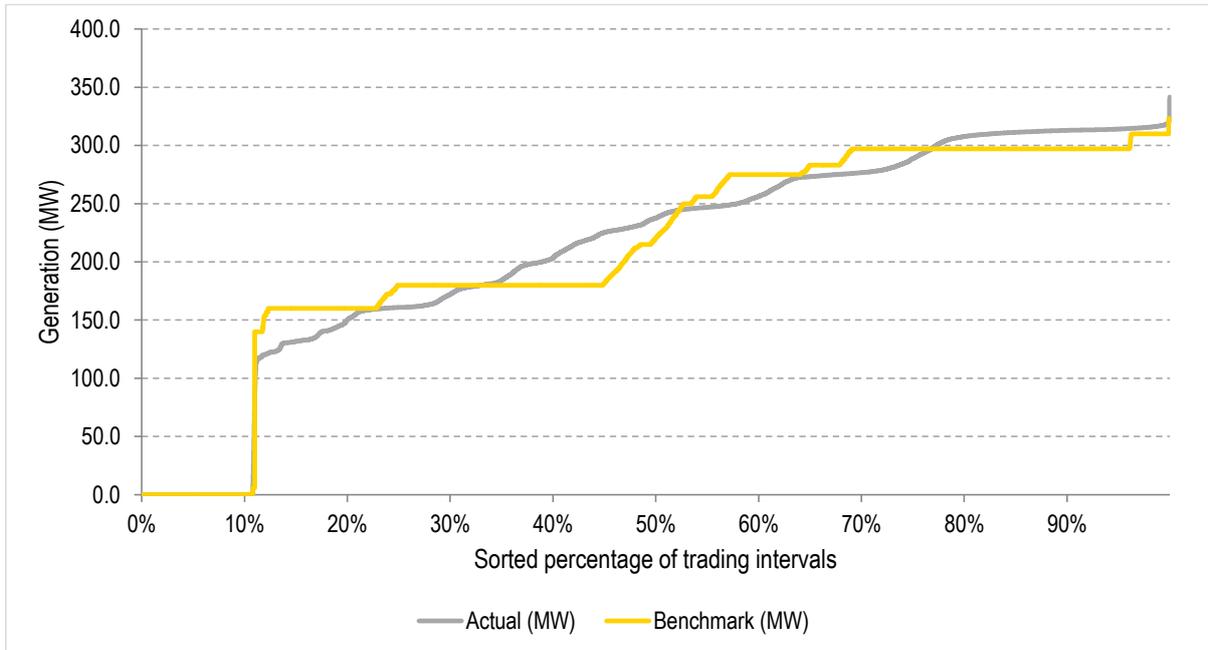
Station name: Cockburn Power Station

Units included: COCKBURN_CCG1



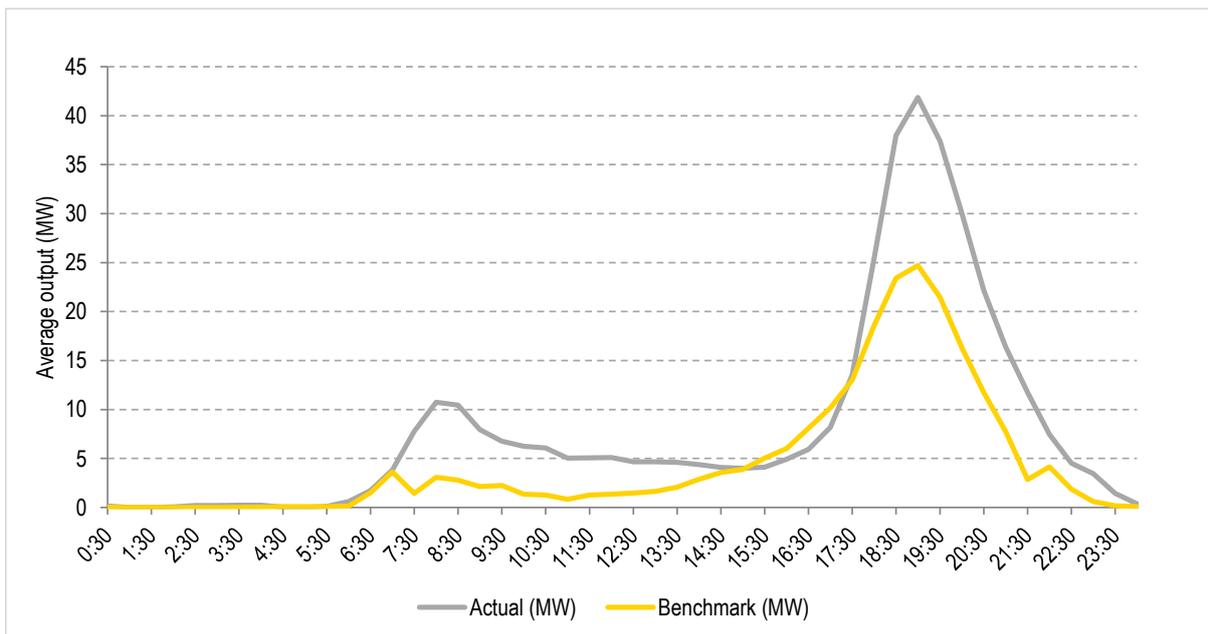
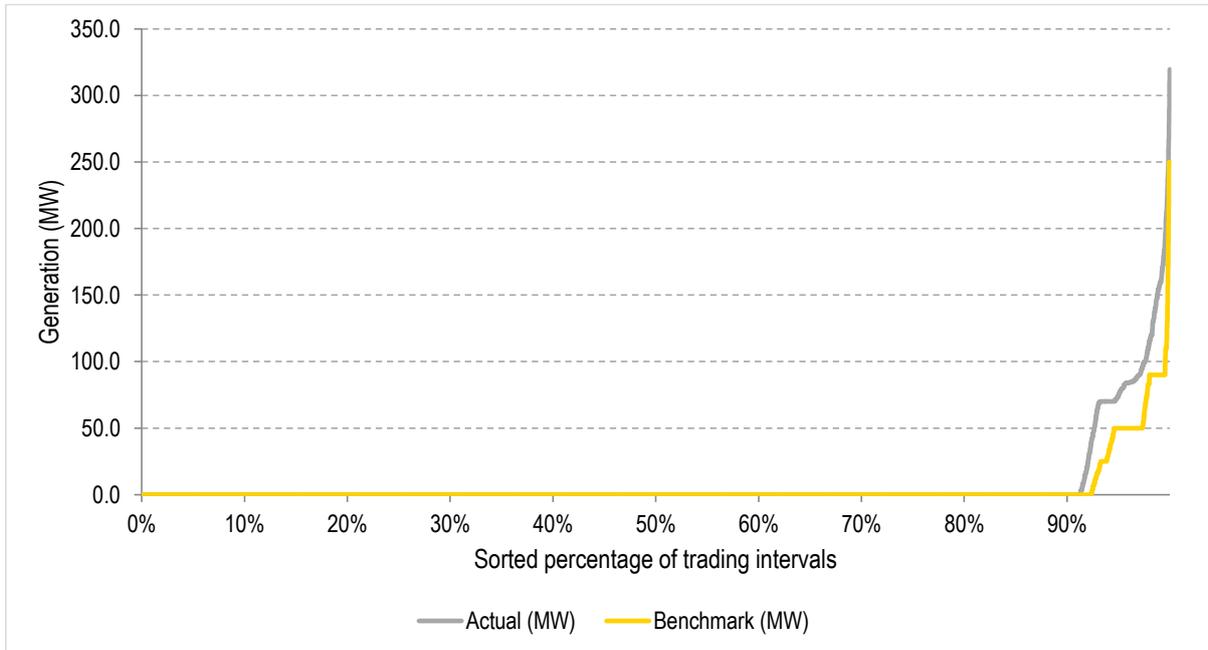
Station name: Collie Power Station

Units included: COLLIE_G1



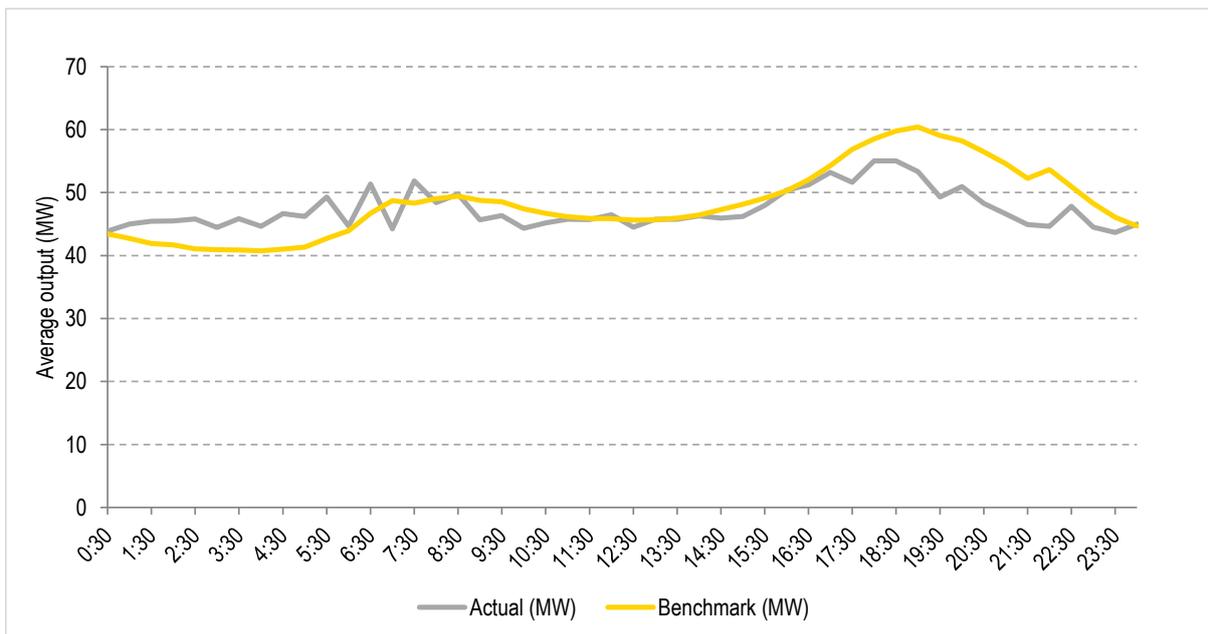
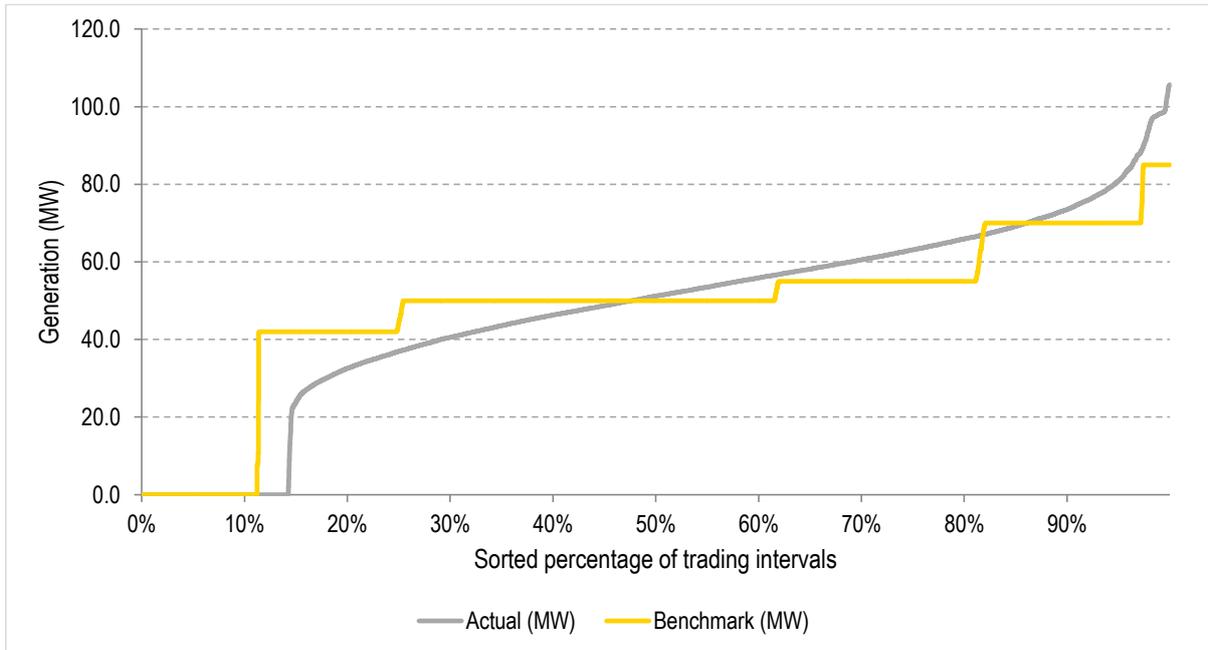
Station name: Kemerton Power Station

Units included: KEMERTON_GT11, KEMERTON_GT12



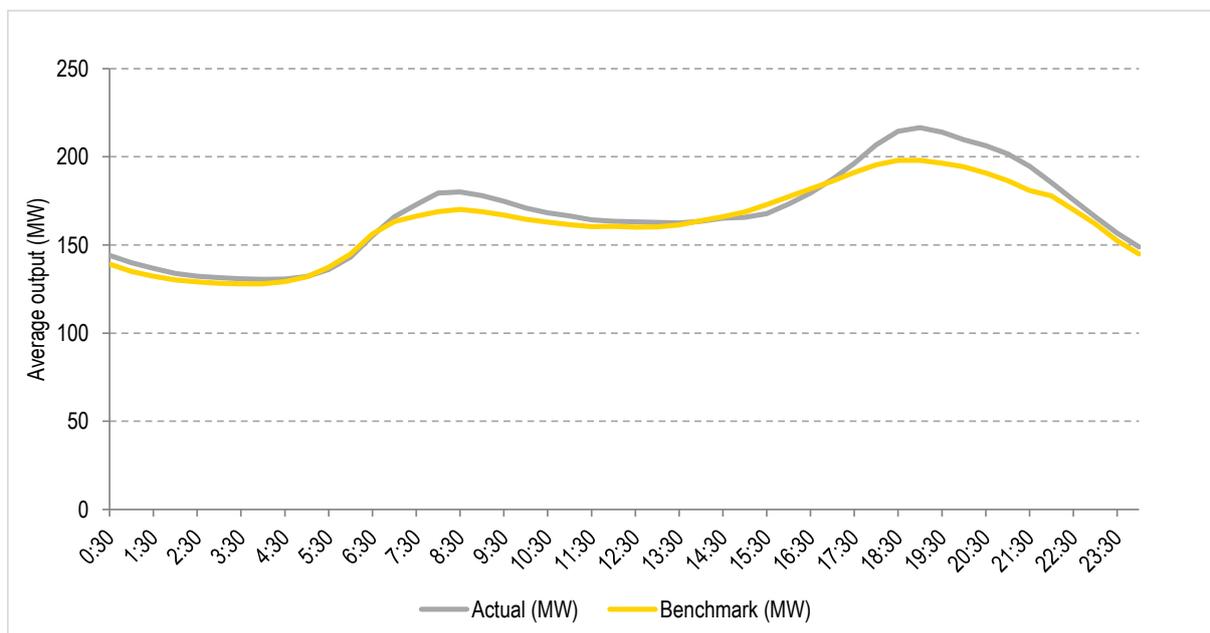
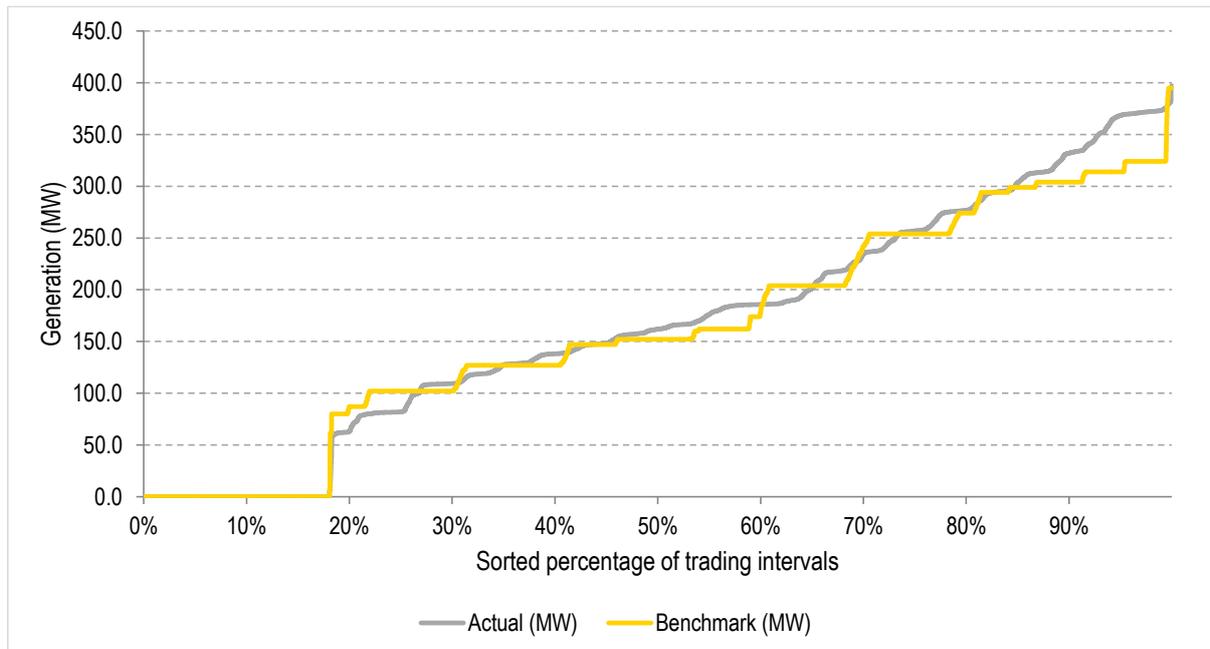
Station name: Kwinana Power Station

Units included: KW_HEGT2



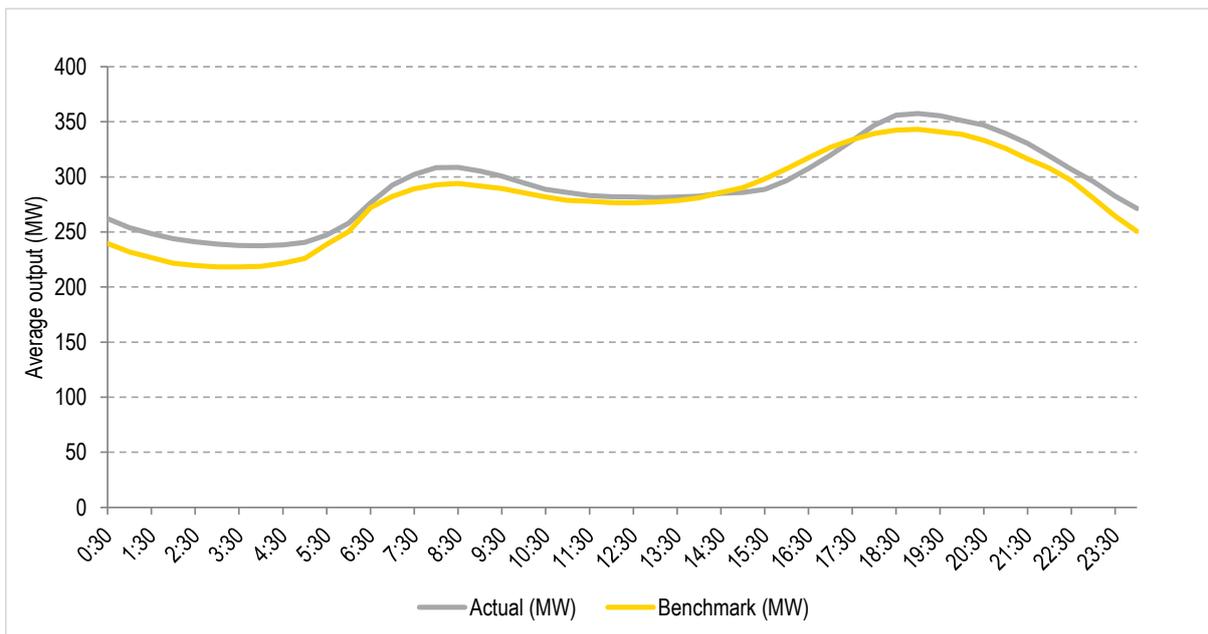
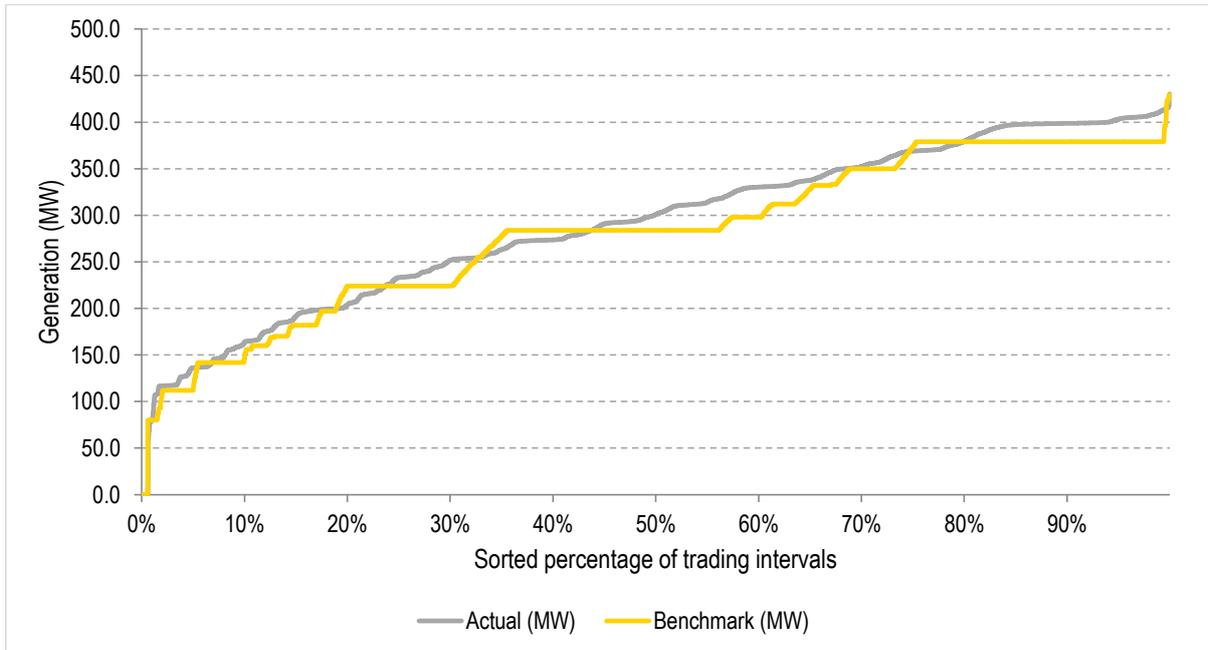
Station name: Muja Power Station C

Units included: MUJA_G5; MUJA_G6



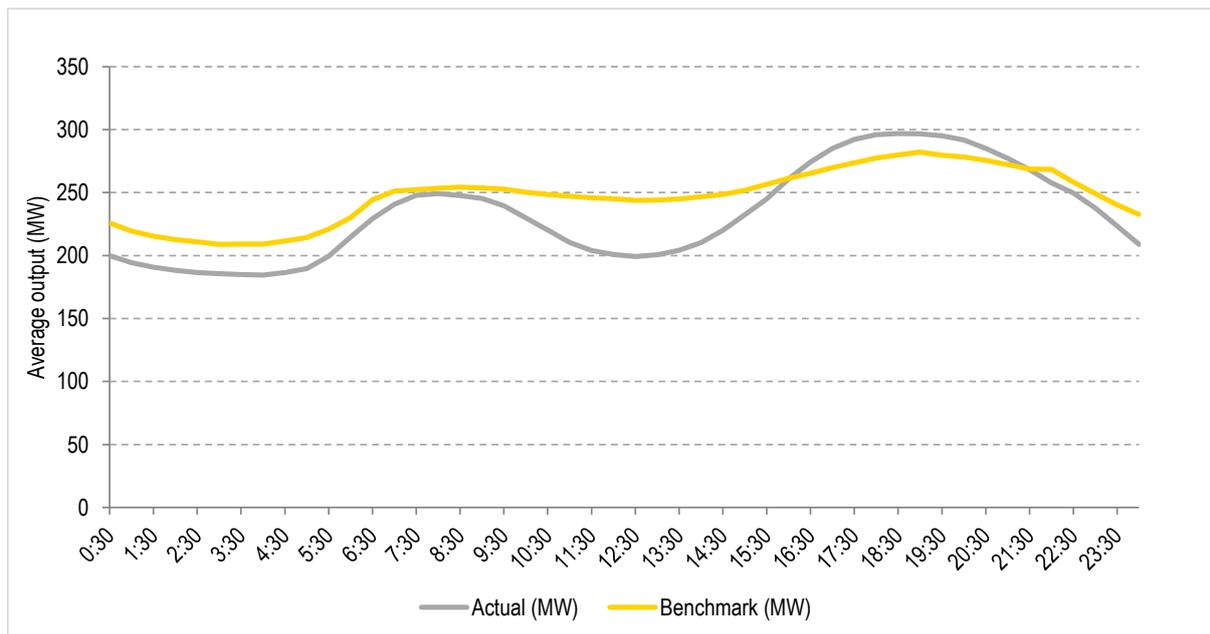
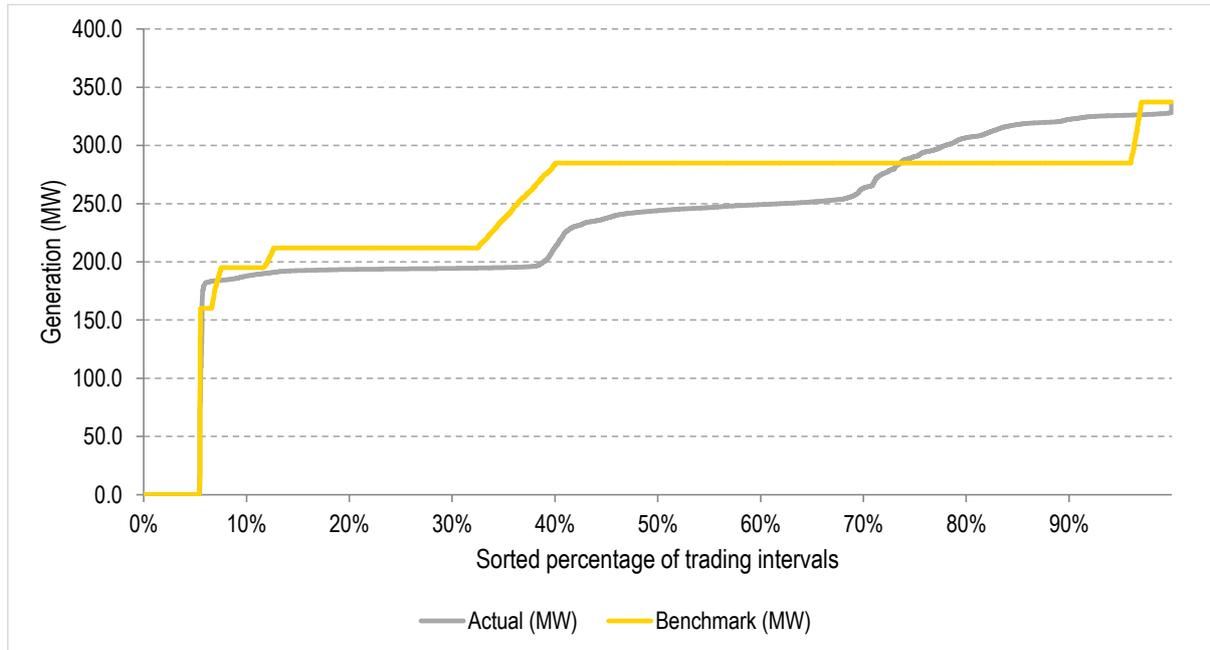
Station name: Muja Power Station D

Units included: MUJA_G7; MUJA_G8



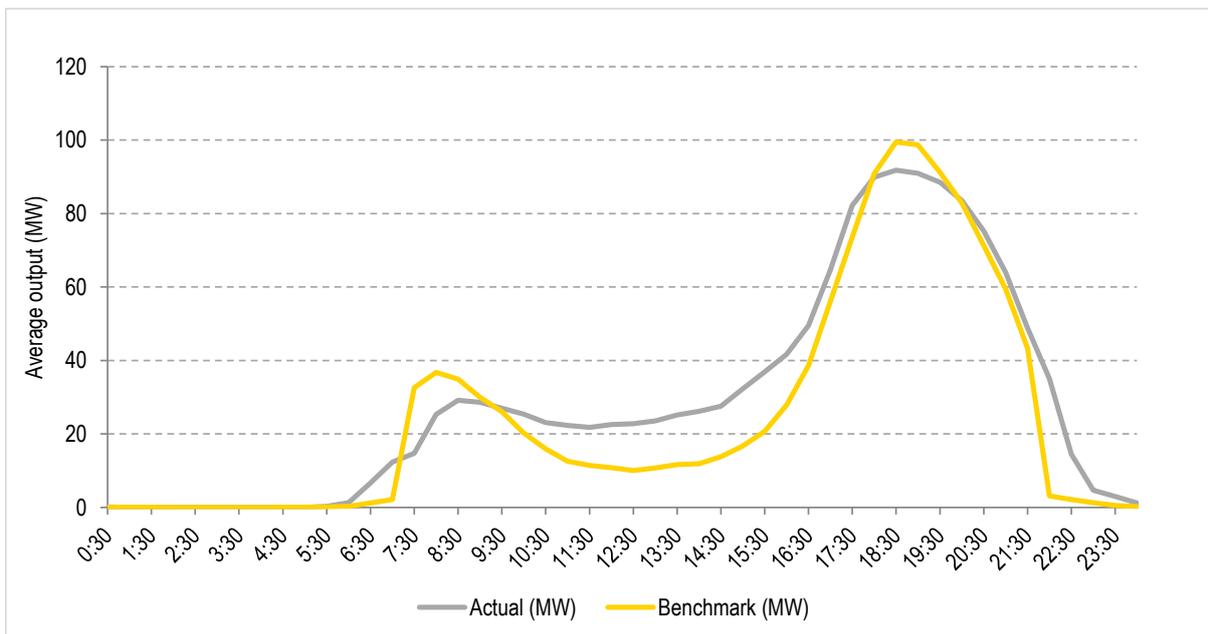
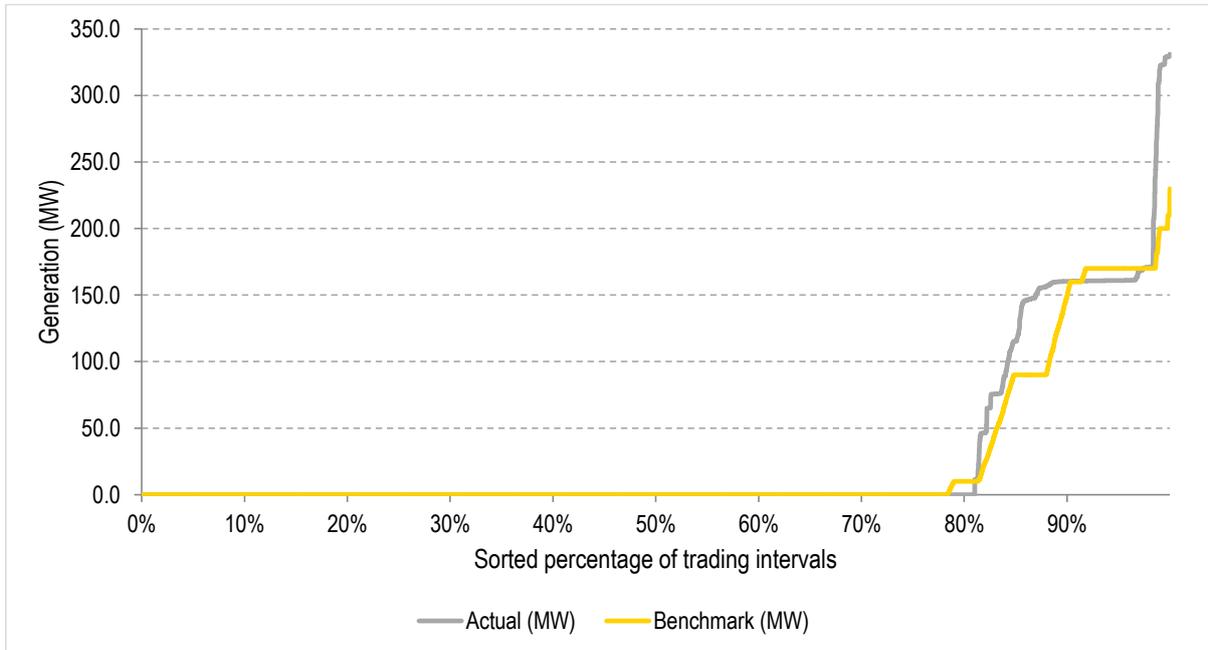
Station name: NewGen Kwinana Power Station

Units included: NEWGEN_KWINANA_CCG1



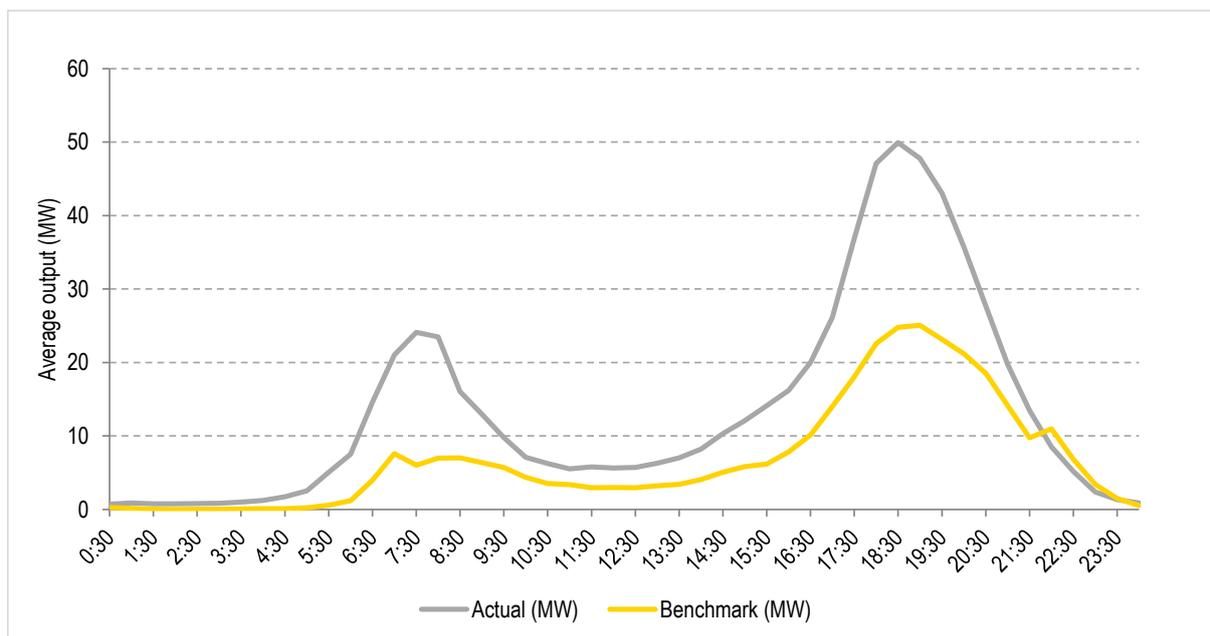
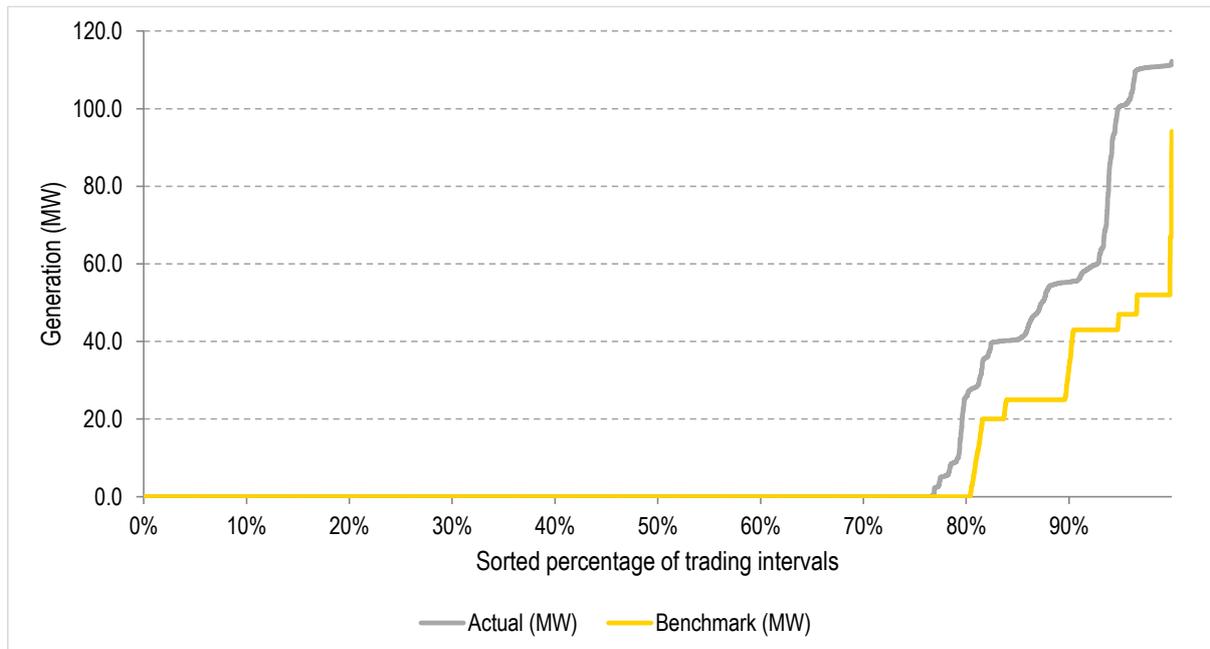
Station name: NewGen Neerabup

Units included: NEWGEN_NEERABUP_GT1



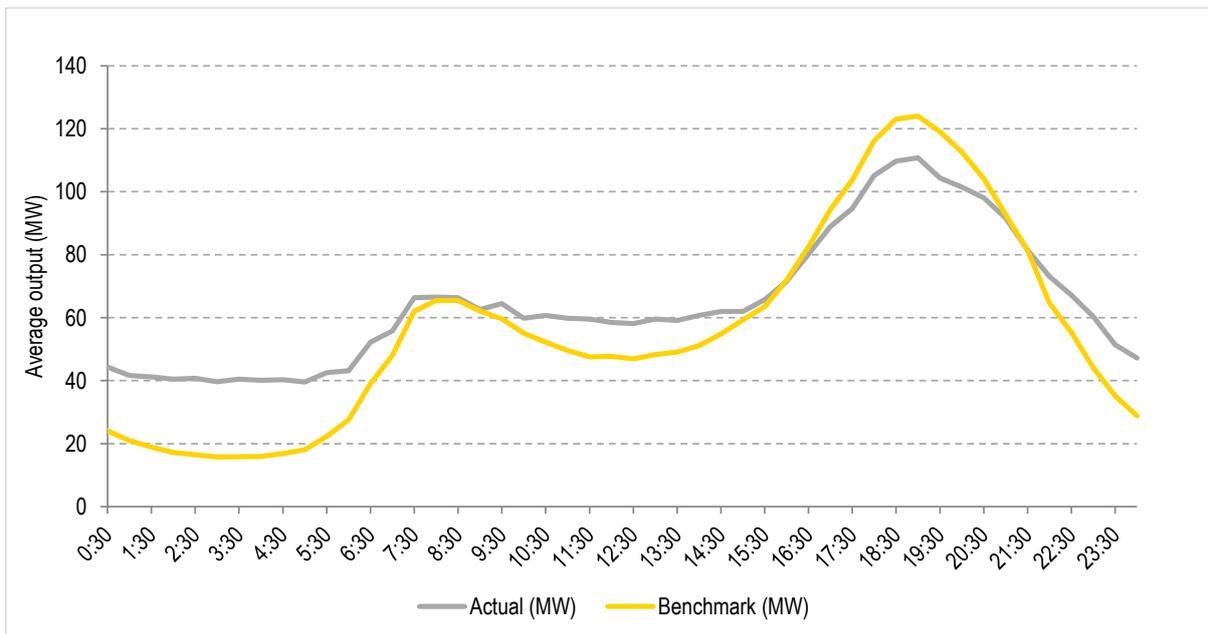
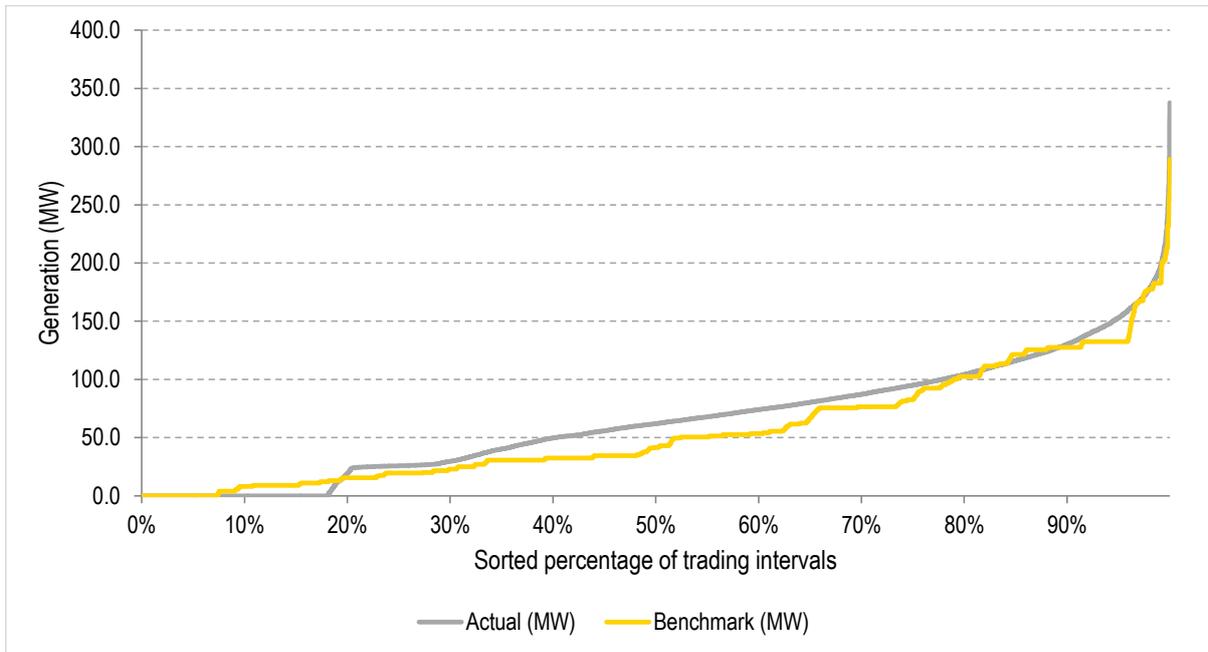
Station name: Perth Energy Power Station

Units included: PERTHENERGY_KWINANA_GT1



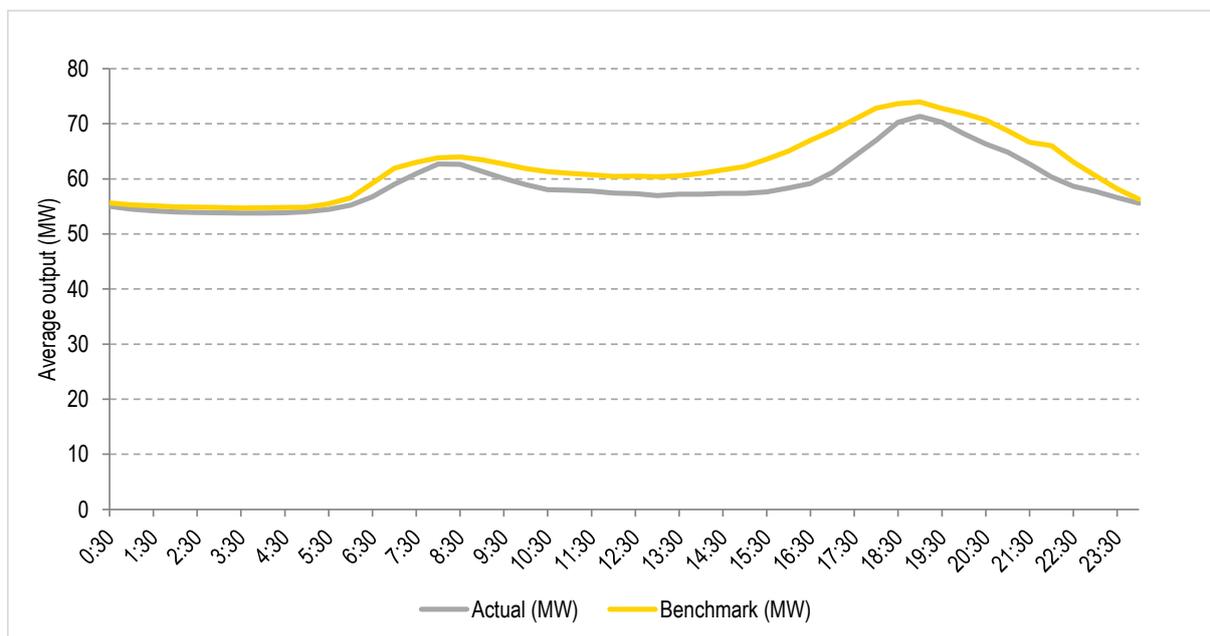
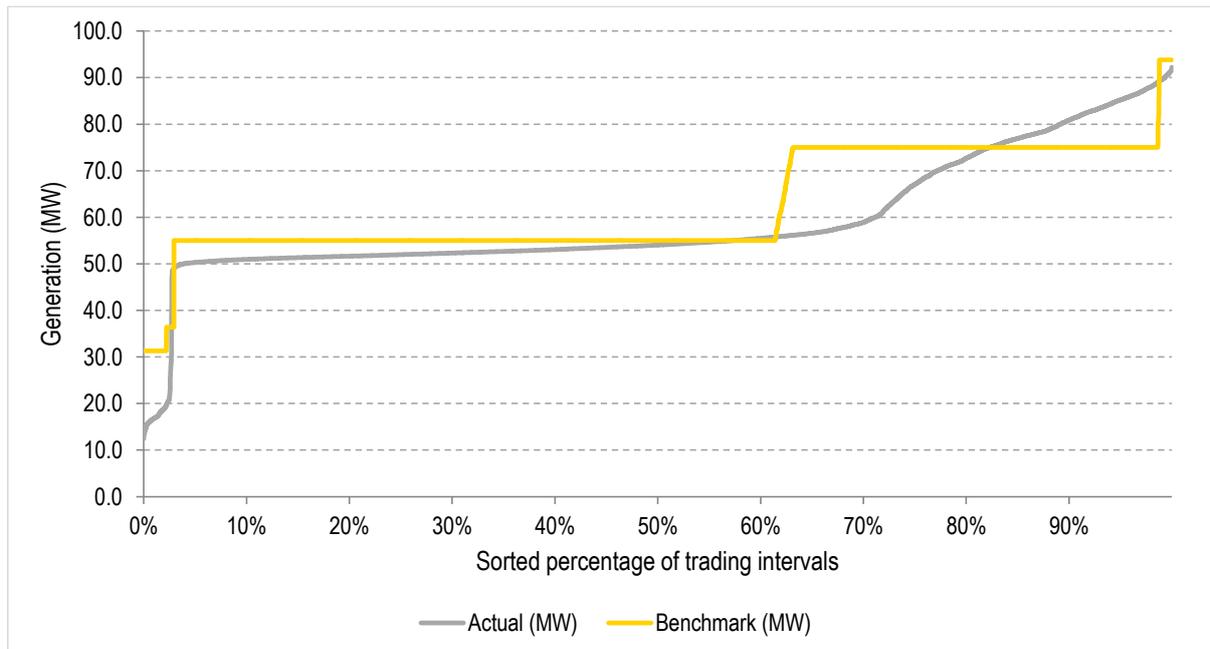
Station name: Pinjar Power Station

Units included: PINJAR_GT1, PINJAR_GT2, PINJAR_GT3, PINJAR_GT4, PINJAR_GT5, PINJAR_GT7, PINJAR_GT9, PINJAR_GT10, PINJAR GT11



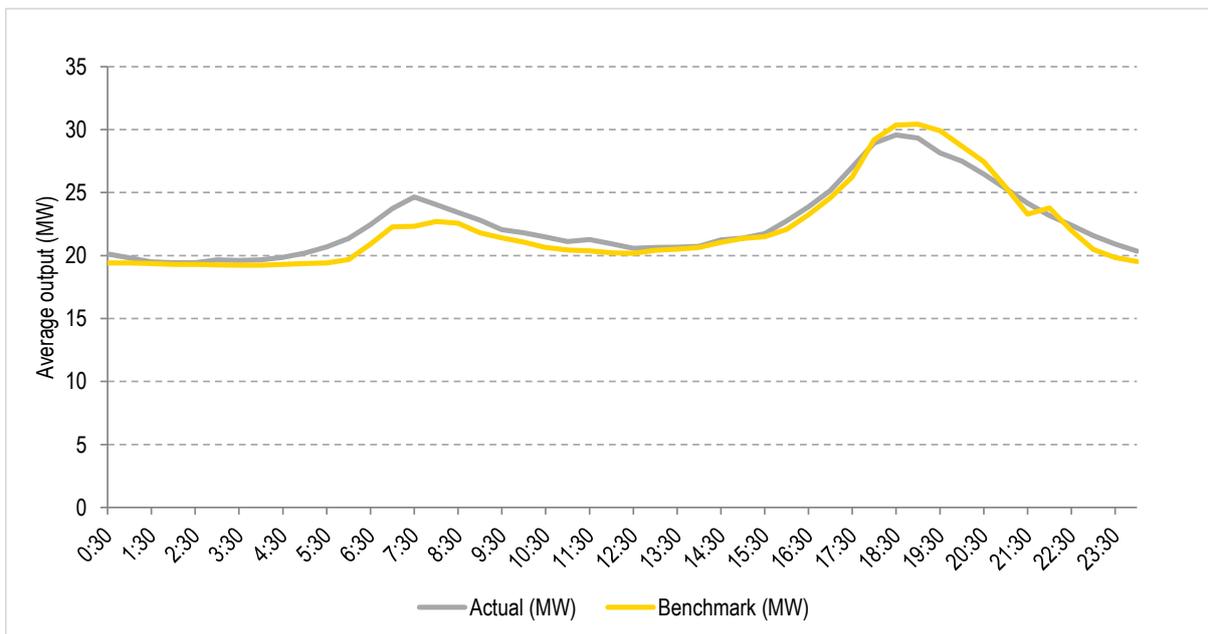
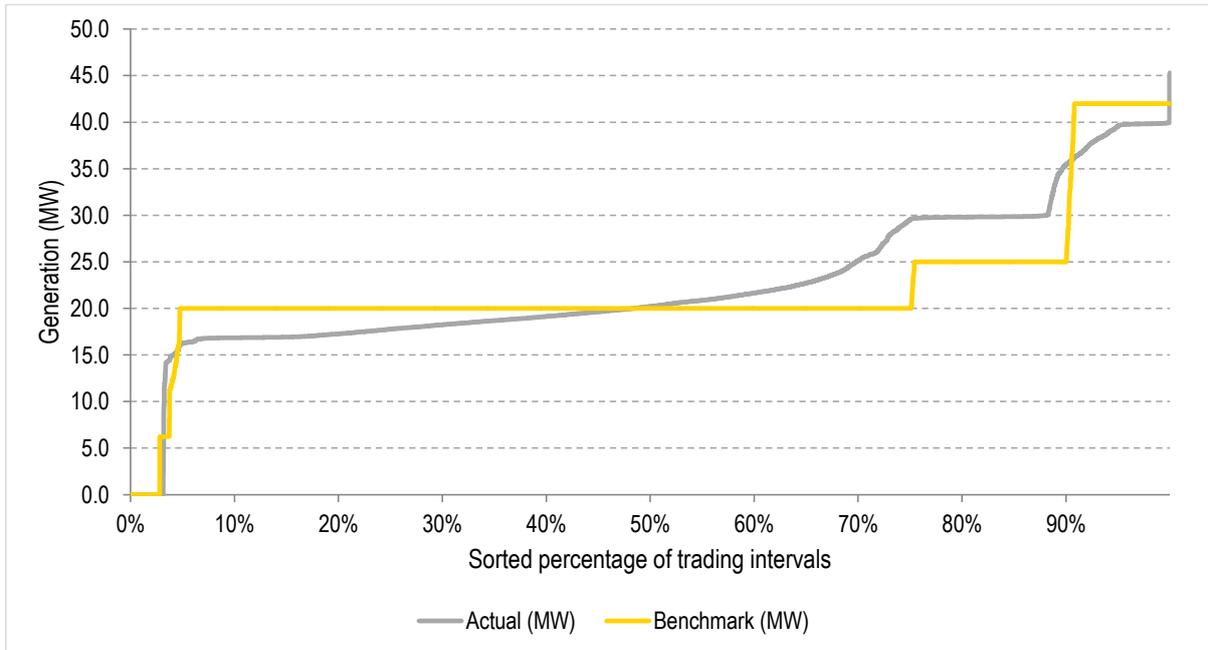
Station name: Kwinana Power Partners

Units included: PPP_KCP_EG1



Station name: Tiwest Cogen

Units included: TIWEST_COG1



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