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GAS POWERED GENERATION FORECAST MODELLING 2020 - FINAL REPORT

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Executive Summary

The Gas Services Information (GSI) Rules[1] require AEMO to produce a Gas Statement of Opportunities (GSOO) report for Western Australia (WA) on an annual basis. The WA GSOO must include a forecast of gas demand over a 10-calendar year horizon. One of the key drivers of gas demand is the amount of gas-powered generation (GPG) which is expected to be dispatched over this horizon.

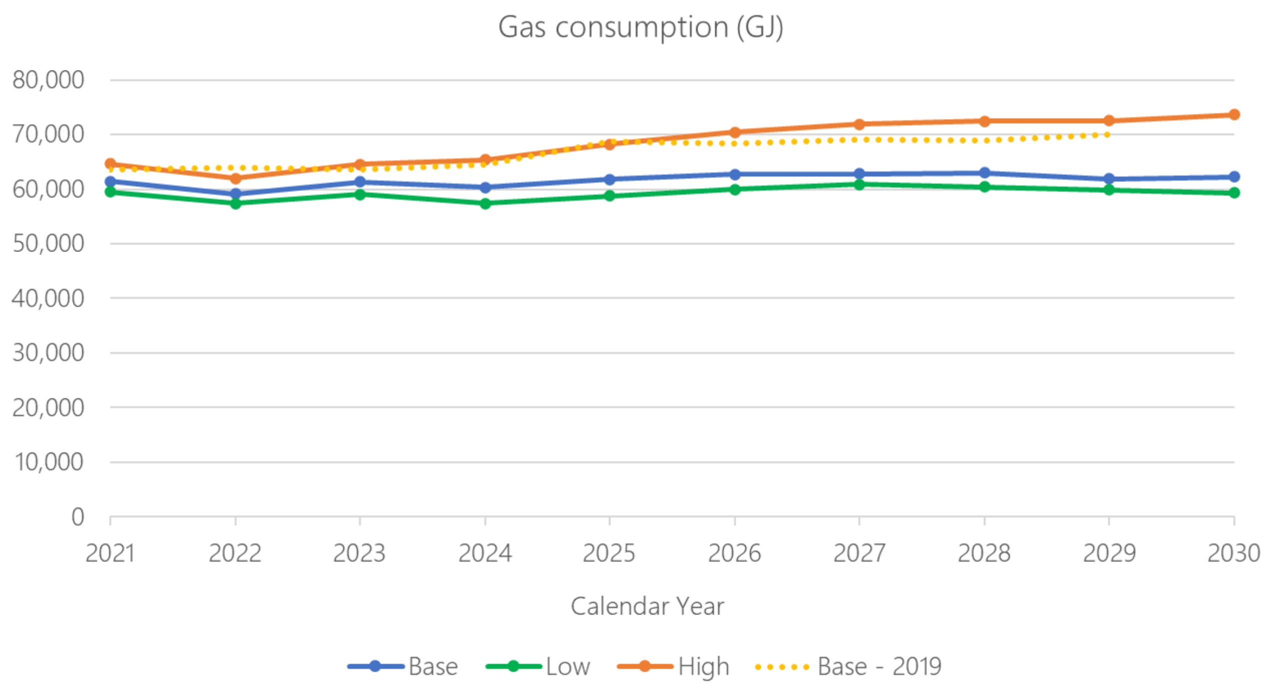
AEMO has engaged RBP to forecast gas demand from GPG in the South West interconnected system (SWIS) across three scenarios reflecting high, expected (base) and low gas demand, over a 10-calendar year horizon (2021 - 2030)

Results

Gas Consumption

Figure 1 shows the annual total gas consumption from GPG from the model results (on a calendar year basis). Base scenario gas consumption from the 2019 GPG forecasts is included for comparison.

Figure 1: Gas consumption



[1] See https://www.erawa.com.au/rule-change-panel/gas-services-information-rules.

Gas consumption in the Base scenario is lower than the 2019 Base scenario, with the 2019 result more closely resembling the High scenario from this year's modelling. This is due to a combination of higher gas prices, increased renewable generation and lower operational peak demands and energy consumptions in the modelling assumptions this year.

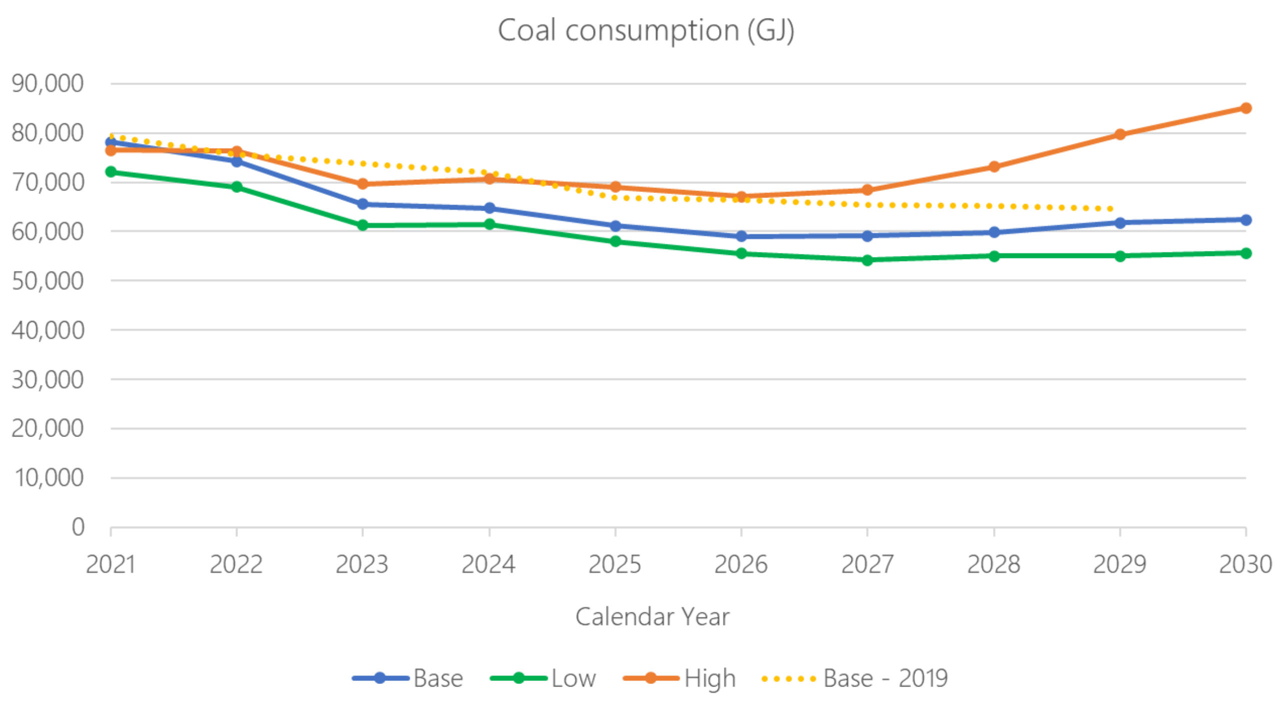
Consumption is relatively flat in the Base/Low scenarios with slight increases in 2023 and 2025 following the retirements of Muja G5 (1/10/2022) and G6 (1/10/2024) [2].

There are relatively large differences between the High and Base/Low scenarios with the High scenario having higher gas consumption from the beginning of the modelling horizon and steady growth from 2023 onwards. This is driven by lower fuel prices and higher operational demands which grow over the modelling horizon.

Coal Consumption

Figure 2 shows the annual total coal consumption for electricity generation from the model results.

Figure 2: Coal consumption



[2] See https://www.synergy.net.au/About-us/News-and-announcements/Media-releases/Synergy-to-retire-Muja-Power-Station-Unit-C-over-five-years#:~:text=Muja%20stage%20C%20unit%205,generated%20at%20the%20power%20station.

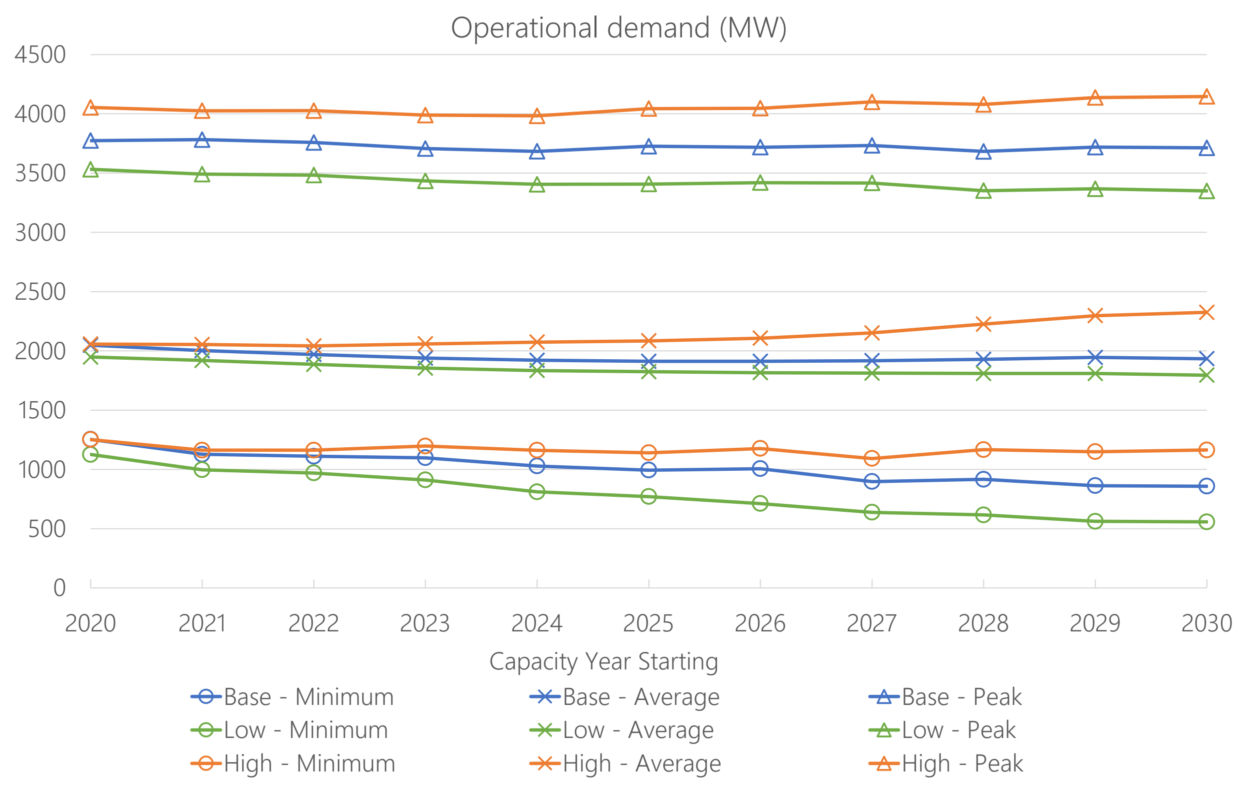
In all scenarios, coal consumption decreases over the first half of the modelling horizon. The increase in average operational demand for the High scenario drives higher coal consumption from 2027 onwards.

In the Low scenario, coal consumption is decreasing or flat across the entire horizon. In the Base scenario, there is a slight uptick in coal consumption in 2029, due to increasing gas prices.

Operational Demand

Figure 3 shows the hourly average, peak and minimum demand for each Capacity Year in the modelling horizon.

Figure 3: Minimum, average, and peak operational demand



There is a much larger spread between demand scenarios in this year's modelling when compared to last year's modelling[3]. In particular:

- There is a large increase in average operational demand in the High scenario. Notably, while the annual operational demands of the Base/Low scenarios are decreasing or flat over the

[3] https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/wa_gsoo/2019/rbp---gpg-gas-demand-forecasts-for-the-swis.pdf?la=en

modelling horizon, the High scenario is 13% higher in the 2030-31 Capacity Year than in 2020-21.

- There are large differences in peak demands between the three scenarios. This is due to our load forecasts using different POE peaks for each scenario (See Section 2.4)
- Minimum demand is lower in the 2030-31 Capacity Year than in 2020-21 for all scenarios. However, for the Base and High scenarios, the load remains above the operational stability constraint. Note that minimum demand forecasts produced by AEMO for the 2020 WEM ESOO have not been reflected in our forecast this year due to changes in AEMO's forecasting methodology[4].

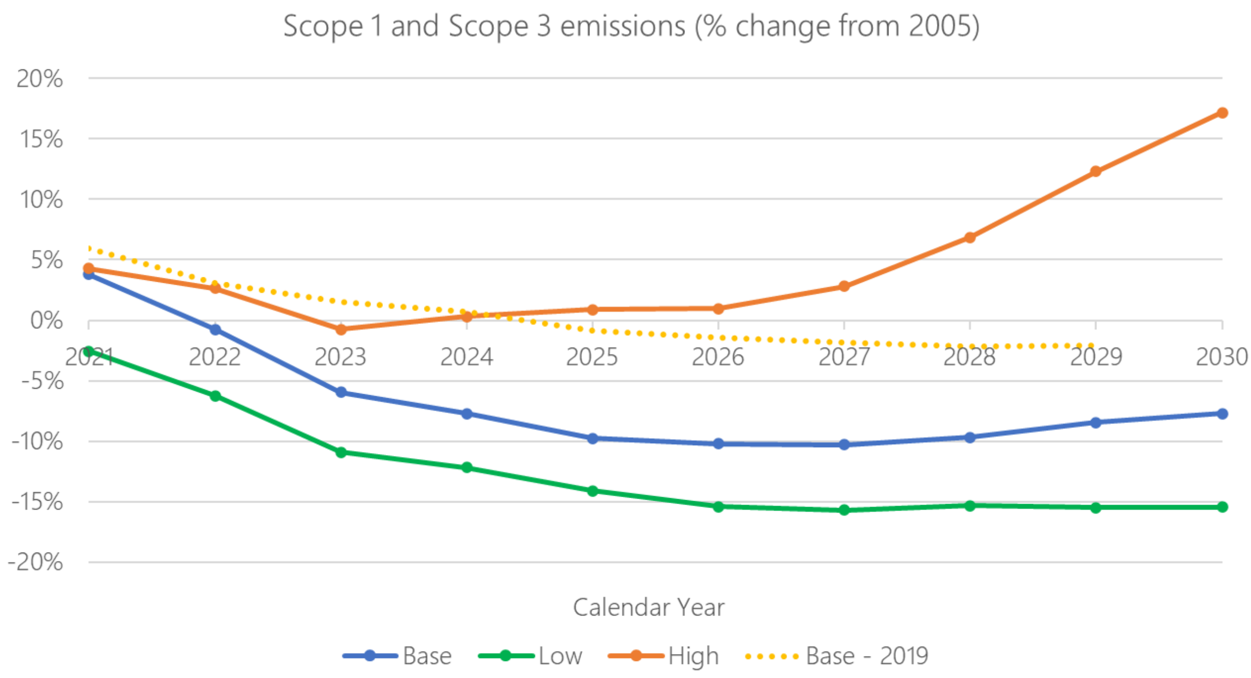
Emissions

Figure 4 shows total annual Scope 1 and Scope 3 emissions from the modelling results, in terms of the percentage change from 2005 levels (positive percentage values showing higher emissions than 2005 levels, negative values showing lower emissions).

The emissions presented here are the direct (Scope 1) and indirect (Scope 3) emissions from the combustion of fuels to generate electricity, so do not include emissions related to the use of electricity, nor the construction or decommissioning of generation plants.

[4] Changes to the forecasting of electric vehicles (EVs) and large industrial loads (LILs) (similar to block loads in the 2019 GPG report) have meant we are unable to capture these elements of demand separately from underlying demand, which has restricted our ability to reflect AEMO's minimum demand forecasts. LILs in particular, can have a large impact on minimum demand where multiple loads are on outage (i.e. not contributing to demand) in already low demand periods.

Figure 4: Emissions



In all three scenarios, emissions drop in the first three years of the modelling horizon, leading to all scenarios having lower emissions in 2023 than in 2005.

For the High scenario, emissions begin to slowly increase from 2024 onwards and greater coal consumption leads to steep increases in emissions from 2027 onwards.

In both the Base/Low scenarios, emissions decrease quickly until 2024 and then level out from 2025 onwards. There is a slight uptick in Base scenario emissions in 2029, reflecting slightly increased coal consumption.

Key Insights

The following key insights can be drawn from our analysis:

- Gas consumption for the Base/Low scenarios has decreased from last year due to higher fuel prices for the base scenario and lower operational energy consumption.
- Operational peak demand and energy consumption has a large impact on gas consumption. As the spread of the 2020 WEM ESOO forecasts is larger this year (especially the High scenario), we have greater differences between scenarios when compared to last year's modelling.

- None of the three scenarios presented here result in emissions reductions that approach the Australian government target of 26-28%[5] reductions by 2030 under the Paris Agreement. Meeting this target will require measures such as further coal plant retirements and significant increases in renewable generation, both of which will significantly impact gas demand for GPG

5 https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Australia%20First/Australias%20Intended%20Nationally%20Determined%20Contribution%20to%20a%20new%20Climate%20Change%20Agreement%20-%20August%202015.pdf

Contents

1 INTRODUCTION

1.1 PROJECT BACKGROUND

The Gas Services Information (GSI) Rules[6] require AEMO to produce a Gas Statement of Opportunities (GSOO) report for Western Australia (WA) on an annual basis. The WA GSOO must include a forecast of gas demand over a 10-calendar year horizon. One of the key drivers of gas demand is the amount of gas-powered generation (GPG) which is expected to be dispatched over this horizon.

AEMO has engaged RBP to forecast gas demand from GPG in the South West interconnected system (SWIS) across three scenarios reflecting high, expected (base) and low gas demand, over a 10-calendar year horizon (2021 - 2030)

1.2 PURPOSE OF THIS DOCUMENT

This document is the final deliverable of the GPG forecast project. This report includes:

- The finalised methodology and assumptions
- A summary of the modelling results
- Key insights and observations
- An assessment of limitation and gaps of the modelling methodology and results

[6] See https://www.erawa.com.au/rule-change-panel/gas-services-information-rules.

2 FINAL METHODOLOGY AND ASSUMPTIONS

In this section we specify the methodology and assumptions used to perform the GPG forecast modelling.

The input data assumptions for the modelling are a combination of:

- Data provided by AEMO specifically for this project
- Data and methodologies used for the 2020 Reliability Assessment[7]
- Publicly available data from AEMO and other sources
- RBP's own knowledge and insights

This section specifies the data that has been used for the modelling, the methodologies used to derive or obtain this data, the data sources that were used, and the simulation model used to obtain the results.

2.1 SIMULATION MODEL

We have used RBP's in-house dispatch optimisation tool WEMSIM to conduct the analysis to produce the forecast.

WEMSIM co-optimises energy dispatch and reserve provision using:

- Generation Facility data such as capacity, outage rates, ramp rates, heat rates and cost information (fuel prices, Variable Operation and Maintenance Costs (VO&M), Fixed Operation and Maintenance Costs (FO&M))
- Transmission data, either via the specification of thermal limits or generic constraints (as used in the National Electricity Market (NEM) and for the Wholesale Electricity Market (WEM) Generator Interim Access (GIA))
- Ancillary Service requirements (Spinning Reserve, Load Rejection Reserve and Load Following Ancillary Service Up/Down) and generator provision data.

2.2 GENERATORS

In this section we set out our assumptions around:

[7] See https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2020/aemo-reliability-assessment-2020---rbp.pdf?la=en

- The technical parameters and operational costs of:
  - Existing generation Facilities
  - New generation Facilities that will come online during the 10-calendar year modelling horizon
- The intermittent generation profiles of:
  - Utility-scale generation Facilities (wind/solar farms and biogas)

2.2.1 Existing Generators

Assumptions for the technical parameters and operational costs of existing generators[8] have been taken from the publicly available AEMO Costs and Technical Parameter Review, completed in 2018 by GHD[9], and refined during the 2019 GPG modelling assignment.

[8] Mungarra and West Kalgoorlie are not modelled as they are under a Network Control Services contract to Western Power, so are not dispatched for energy in the WEM. We have therefore assumed that they will be inactive over the modelling horizon.

[9] Available from https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/GHD-AEMO-revised---2018-19-Costs_and_Technical_Parameter.xlsb

2.2.2 Retirements

The following retirements[10] are assumed to occur during the modelling horizon:

Table 1: Retirements

Unit	Retirement Date
MUJA_G5	1 October 2022
MUJA_G6	1 October 2024

2.2.3 New Build

There are two new generators coming online during the modelling horizon. These Facilities are listed in Table 2 below:

Table 2: New build - technical parameters and costs

Unit name	Commencement Date	Type
ERRRF_WTE_G1	1/10/2022	Biomass - electricity only
PHOENIX_KWINANA_WTE_G1	1/10/2021	Biomass - electricity only

[10] See https://www.synergy.net.au/About-us/News-and-announcements/Media-releases/Synergy-to-retire-Muja-Power-Station-Unit-C-over-five-years#:~:text=Muja%20stage%20C%20unit%205,generated%20at%20the%20power%20station.

2.2.4 Utility-Scale Intermittent Profiles

Treatment of intermittent generation

We have applied the methodology used in the 2020 Reliability Assessment[11] to derive intra-day hourly profiles for each intermittent utility-scale Facility[12]. This has resulted in 12 intra-day profiles for each of the 24 Intermittent Facilities.

2.2.5 Outages

Forced Outages

We have used the forced outage assumptions developed for the 2020 Reliability Assessment. These were developed by analysing historical forced outage rates (FORs) over a 36-month period.

We have assumed a FOR of 0.1% for Facilities with a zero historic FOR (mainly Intermittent Facilities). Assuming a FOR of 0% for these Facilities is unrealistic as equipment is unlikely to have a zero failure rate over the ten-calendar year modelling horizon.

We have also included a Mean Time to Repair (MTR) value which denotes the amount of time a plant will be offline following a forced outage event. This value is derived by classifying plants into short (12 hours), medium (24 hours), and long (144 hours) duration outage plants, based on historical downtimes. For new plants, we have assumed forced outage rates and mean times to repair will be similar to current plants of a similar technology.

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[11] This was as follows:

- For each month (Jan, Feb, …, Nov, Dec), assign an intra-day hourly profile to each intermittent generator.
- Each intermittent generator has 12 intra-day hourly profiles (one for each month of the year).
- Hence, $\overline{Gen_{h,m}} = \sum_{Y\ (Years)=1}^{T} \left(\frac{\sum_{d\ (days) \in Month\ m} Gen_{Y,h,d} \Big/ \#\ days\ in\ month\ m\ of\ Year\ Y}{T} \right)$

  For a given intermittent generator:
  - $\overline{Gen_{h,m}}$ denotes the average generation (MW) in hour h of month m (based on T years of historical or participant provided generation values)
  - $Gen_{Y,h,d}$ denotes the historical or estimated generation value in hour h or day d (in month m) of Year Y.

[12] Profiles of existing intermittent generation were derived using historical non-loss adjusted metered quantities over the entire generation history for each plant. Profiles for new intermittent generation were derived using participant provided estimated generation (which AEMO provided RBP to conduct the 2020 Reliability Assessment).

Planned Outages

As part of the 2020 Reliability Assessment, AEMO provided RBP with participant provided planned outage schedules from 2021 to the end of 2030. We have reused these for the GPG forecasting (zeroing out the relevant Facilities' capacity on dates where a participant has indicated an outage).

2.2.6 Emissions Factors

The quantity of carbon emissions resulting from electricity generation has been calculated in WEMSIM, based on emissions factors published by AEMO for existing and new generators in the SWIS[13].

2.2.7 Operational Stability Constraint

AEMO have advised a minimum stable load that can be maintained. At this level of load, all generation must be synchronous thermal generation to maintain system stability. Above this level of load, a minimum of synchronous thermal generation (from certain generators) must be scheduled to maintain system stability.

To implement this requirement, we add a constraint that a minimum level of thermal generation from a subset of generators must be maintained at all times. Should demand fall below this level, a violation penalty price is be incurred, which sets the resulting market price. The presence of this penalty in the market price results indicates an unstable level of system demand.

2.2.8 Other Operational Constraints and Offer Patterns

To replicate actual generation patterns, additional operational constraints are placed on some plant. These are based on advice provided by AEMO.

The WEMSIM model assumes by default that generators offer their capacity at their Short Run Marginal Cost (SRMC). An analysis of actual historical balancing market offers[14] (which are publicly available from the AEMO website) shows that many generators offer all or a portion of their capacity at negative (or otherwise reduced compared to their modelled SRMC) prices to ensure that they are dispatched.

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[13] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Data_Sources/ACIL-ALLEN---AEMO-Emissions-Factors-20160511.pdf and https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Data_Sources/ACIL-ALLEN---AEMO-Emission-factors-20160511.xlsx.

[14] 1 Jan 2019 – 31 July 2019

2.3 Transmission Network and Constraints

The WEM currently operates on an unconstrained basis, with GIA constraints used to manage the output of new GIA generators. Remaining generators are dispatched on an unconstrained basis using the Balancing Merit Order but can be constrained on or off in real-time to manage system security; when this occurs, participants are eligible to receive constraint payments.

It is expected that on 1 October 2022, Security Constrained Economic Dispatch (SCED) will be implemented on the basis of a single region hub and spoke model with a reference node located at Southern Terminal.

The GSOO horizon comprises 2021 to 2030. Hence, we have needed to form a view on what market design assumptions to adopt from 1 October 2022 onwards. We have adopted the following approach:

- Model the existing WEM with GIA constraints only for the period up to 30 September 2022 , excluding real-time interventions and subsequent constraint payments.
- From 1 October 2022 onwards assume that NEM style SCED will apply (namely a single zone hub and spoke market with the reference node at Southern Terminal).

2.4 Demand

Our demand forecasting methodology has been taken from the 2020 Reliability Assessment.

This methodology was designed to capture ongoing and expected future changes in load shapes and the timing of peak periods (load chronology) in the SWIS, by modelling the impacts of behind-the-meter (BTM) generation. It involves creating underlying demand forecasts[15], and subtracting forecasted BTM PV and battery contributions to create preliminary hourly operational forecasts; which are then converted into a load profile. This load profile is then scaled to ensure alignment with AEMO's forecast operational summer peak and annual sent-out energy demand forecasts.

Note that while the modelling horizon for the 2020 Reliability Assessment was in terms of Capacity Years (2020-21 to 2029-30), the GPG modelling horizon is in terms of calendar years (2021-2030). This means that the 2020 Reliability Assessment horizon does not include the last three months of the GPG horizon. We have therefore extended the forecasts provided by AEMO by an additional year using an average growth rate and have undertaken our forecasting process

[15] Based on historical data and AEMO's underlying peak/energy demand forecasts.

for 11 Capacity Years. These forecasts are then mapped to calendar years for input into the modelling.

This approach has five steps:

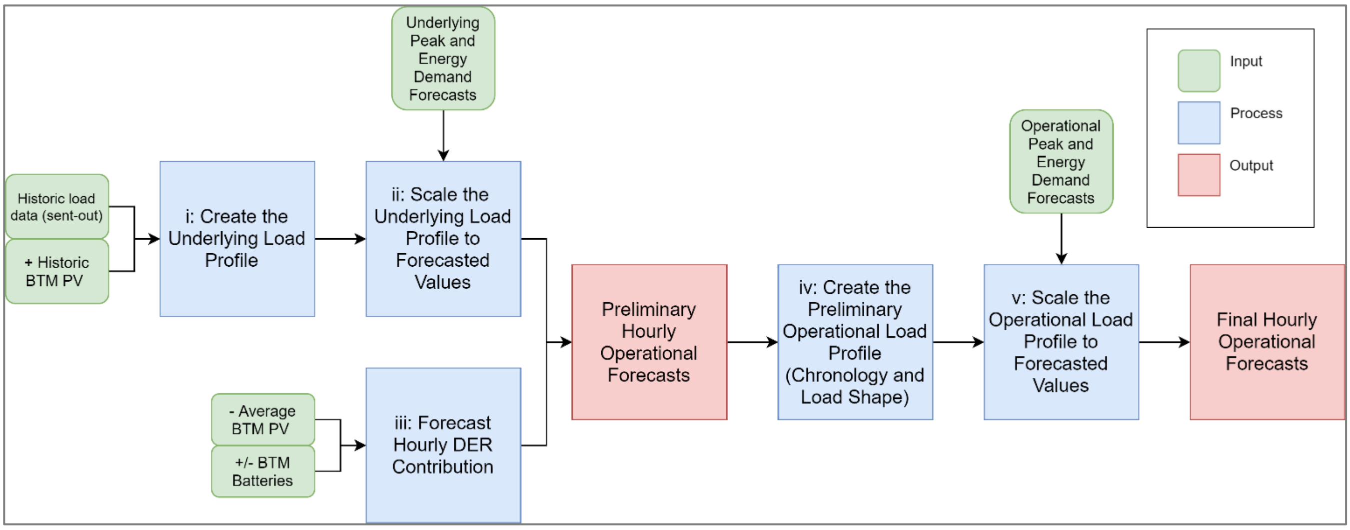
i. Create the underlying load profile: The underlying load shape is developed using historical sent out generation data (adding historical BTM PV generation to get underlying load) to derive an average load shape; this is applied to the 2018/19 load chronology (i.e. the hour with the largest underlying load in 2018/19 is the hour with the largest underlying load in our forecasts and likewise for the 2nd, 3rd – 8,760th hour) to create the underlying reference load profile.
ii. Scale the underlying load profile to forecasted values: Hourly underlying load forecasts for each Capacity Year in the modelling horizon are developed by scaling up the underlying reference load profile to match the underlying 50% POE peak and expected energy forecasts for the respective Capacity Year.
iii. Forecast hourly distributed energy resources (DER) contribution[16]: Using DER data provided by AEMO, we forecast hourly BTM PV generation (averaged across five 'outage sequences' reflecting stochastic weather and cloud cover), and battery charge/discharge, for each Capacity Year.
iv. Create the preliminary operational load profile (chronology and load shape): The hourly underlying load forecasts and hourly DER contribution forecasts are combined and adjusted for losses to create hourly operational load forecasts. These are processed into an operational load profile for each Capacity Year.
v. Scale the operational load to forecasted values: In order to ensure that our hourly operational load forecasts align with the operational peak and annual energy demand forecasts provided by AEMO we scale the operational load profile to forecasted values, producing the final hourly operational load forecasts to be used in the modelling.

Each of the bullets above are described in more detail in the sections below.

Figure 5 provides an overview of the load forecasting process. Boxes in green reference inputs, boxes in blue reference each step in the process (described in more detail in sections 2.4.1 - 2.4.5), while red boxes refer to outputs.

[16] This includes contributions from BTM PV and battery storage uptake but does not include the impact of electric vehicle (EV) consumption.

Figure 5: Overview of load forecasting process



Demand forecasts from the 2020 WEM ESOO have been provided by AEMO and are summarised for each of our GPG scenarios[17] in Tables 8 - 10. We have used the 10% - high demand growth/ 50% - expected demand growth/ 90% - low demand growth POE forecasts (referred to as 10/50/90% POE forecasts in the remainder of this report) for the High/Base/Low scenarios respectively, to reflect differences in forecast annual operational demands and to provide larger variation between scenarios.

[17] See Section 2.7 for further details about our scenario definitions.

Table 3: Demand forecasts - Base scenario

	Underlying Forecasts			Operational Sent-out Forecasts	
Capacity Year	50% POE underlying value (AEMO-provided) (MW)	50% POE peak forecast (scaled[18]) (MW)	Annual Demand - Expected (MWh)	50% POE peak forecast (MW)	Annual Demand - Expected (MWh)
2020-21	3,843	4,192	19,483,723	3,774	17,935,419
2021-22	3,823	4,170	19,275,354	3,782	17,539,137
2022-23	3,786	4,130	19,221,272	3,758	17,253,793
2023-24	3,745	4,085	19,173,287	3,707	16,986,658
2024-25	3,715	4,052	19,213,201	3,684	16,828,732
2025-26	3,754	4,095	19,313,845	3,727	16,746,365
2026-27	3,747	3,970	19,480,259	3,719	16,743,152
2027-28	3,756	4,097	19,690,608	3,726	16,793,621
2028-29	3,714	4,051	19,934,964	3,683	16,888,850
2029-30	3,736	4,075	20,228,851	3,723	17,033,731
2030-31	3,724	4,062	20,313,382	3,717	16,936,384

[18] The forecast underlying values provided by AEMO are scaled up to reflect the timing of the underlying peak. See Section 2.4.2.

Table 4: Demand forecasts - High scenario

	Underlying Forecasts			Operational Sent-out Forecasts	
Capacity Year	10% POE underlying value (AEMO-provided) (MW)	10% POE peak forecast (scaled) (MW)	Annual Demand - High (MWh)	10% POE peak forecast (MW)	Annual Demand - High (MWh)
2020-21	4,249	4,635	19,569,425	4,053	18,024,511
2021-22	4,173	4,551	19,707,242	4,025	17,986,605
2022-23	4,168	4,547	19,831,197	4,026	17,885,946
2023-24	4,113	4,486	20,186,176	3,989	18,036,668
2024-25	4,053	4,421	20,504,412	3,983	18,167,872
2025-26	4,102	4,474	20,769,350	4,044	18,257,001
2026-27	4,069	4,312	21,129,494	4,047	18,455,988
2027-28	4,075	4,445	21,668,152	4,101	18,848,142
2028-29	4,019	4,384	22,445,945	4,080	19,497,832
2029-30	4,035	4,401	23,197,775	4,138	20,119,864
2030-31	4,012	4,376	23,640,351	4,147	20,367,226

Table 5: Demand forecasts - Low scenario

	Underlying Forecasts			Operational Sent-out Forecasts	
Capacity Year	90% POE underlying value (AEMO-provided) (MW)	90% POE peak forecast (scaled) (MW)	Annual Demand - Low (MWh)	90% POE peak forecast (MW)	Annual Demand - Low (MWh)
2020-21	3,593	3,919	18,642,448	3,531	17,064,893
2021-22	3,531	3,852	18,572,580	3,490	16,811,809
2022-23	3,517	3,837	18,512,605	3,482	16,520,198
2023-24	3,464	3,779	18,457,968	3,433	16,245,953
2024-25	3,437	3,749	18,475,232	3,404	16,064,371
2025-26	3,454	3,767	18,571,135	3,406	15,976,784
2026-27	3,460	3,666	18,674,350	3,418	15,907,683
2027-28	3,458	3,772	18,803,602	3,415	15,873,530
2028-29	3,377	3,683	18,934,098	3,350	15,850,058
2029-30	3,425	3,736	19,088,028	3,366	15,849,098
2030-31	3,407	3,717	19,138,189	3,348	15,719,473

2.4.1 Creating the Underlying Load Profile

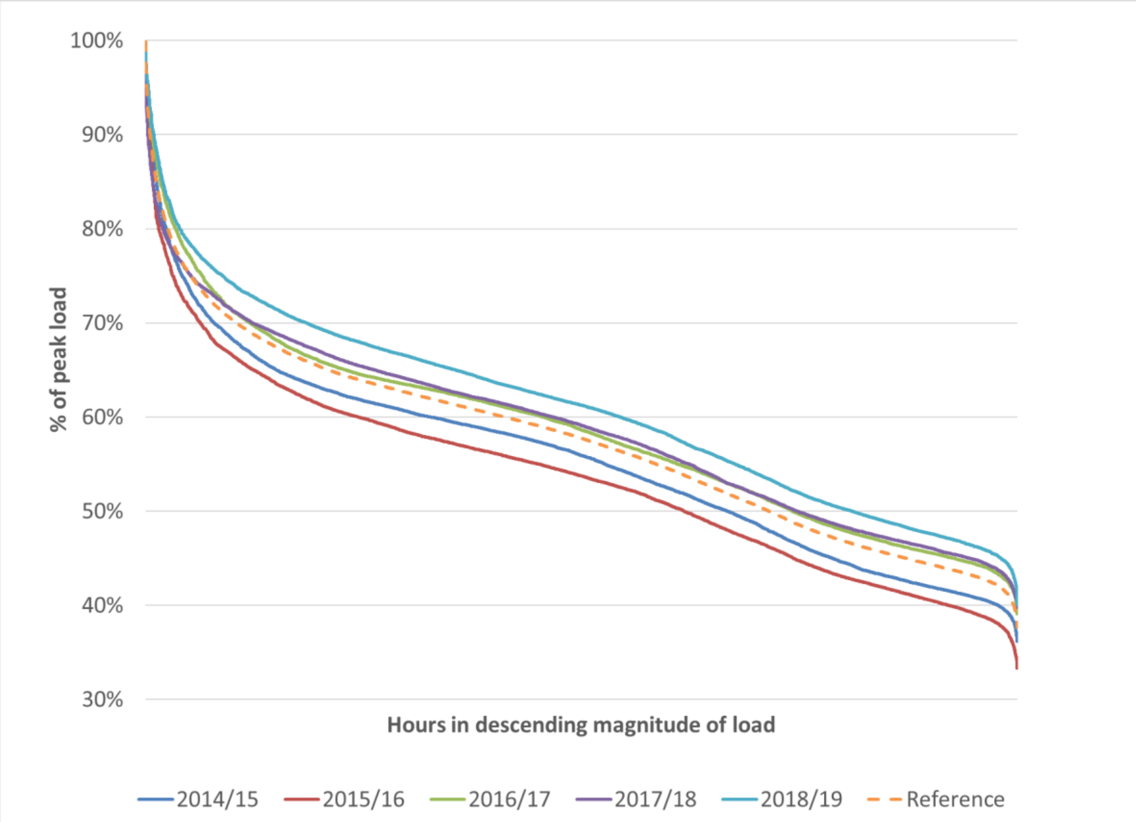
We first develop a ‘reference’ underlying load profile by constructing underlying historical load duration curves (LDCs)[19] for the last five full Capacity Years (2014/15-2018/19), averaging across these five LDCs to construct an average load shape, and applying this underlying average load shape to the most recent load chronology (2018/19). As the historical total sent-out generation from AEMO reflects operational demand and includes the effects of BTM PV generation, we add historical BTM PV generation[20] (provided by AEMO) to the historical load data before conducting the above analysis.

[19] A load curve ordered in descending order

[20] PV DER generation causes total sent out generation to be lower than underlying demand.

We use the average load profile to ensure that the underlying demand profile reflects a representative underlying load shape, while ensuring that more recent trends are captured[21]. Figure 6 below shows the reference load shape:

Figure 6: Underlying reference load shape



2.4.2 Scaling the Underlying Load Profile to Forecasted Values

The next step in our load forecasting methodology is to scale the underlying profile to match the underlying 10/50/90% POE peak forecast and expected demand in any given year. This is done for each of the three scenarios to create three underlying load forecasts, each representing a different peak forecast.

Note that the underlying 10/50/90% POE forecasts provided by AEMO represent the underlying demand occurring at the time of the operational forecast peak, rather than the maximum underlying demand over the forecast year.

Historically, the peak underlying demand and the peak operational demand generally occur on the same day. However, the underlying peak demand occurs earlier in the day and will be higher

[21] Note that our historical load chronology does not include the recent 2020-21 summer peak (which was particularly high) and would lead to relatively higher summer loads in the historical load profile. This peak was primarily driven by very hot temperature conditions leading to high underlying demand (with a maximum temperature of 43°C on the peak day, after two consecutive hot days of over 35°C.).

than the underlying demand occurring at the time of operational peak. AEMO has provided the time of operational peak for each forecast year and we have scaled up the underlying values provided by AEMO to represent the underlying 10/50/90% POE peak. This scaling is based on the average historical difference between the peak underlying demand and the forecast time[22] of operational peak, on the operational peak day.

Having scaled the underlying value to the underlying peak, for each year of the LT-PASA forecast horizon we produce a forecasted load profile with a shape such that:

- The peak of the load profile equals the 10/50/90% POE peak forecast
- The load allocated across all hours sums to the expected underlying annual demand consumption forecast and
- The shape of the profile should be "close" to the reference year profile developed above.

We have defined a function F(h) (h ∈ hours of the year), such that the shape underlying the profile for a given year t ($\widehat{PROF}(h)$) can be derived by multiplying the average load shape ($\overline{PROF}(h)$) by this function. That is:

- $\widehat{PROF}(h) = F(h) \times \overline{PROF}(h)$, such that:
  - $Max\left(\widehat{PROF}(h)\right)$ = underlying POE peak forecast in year t and
  - $\sum_{h=1}^{8760} \widehat{PROF}(h) =$ underlying expected demand forecast in year t.

The function is defined to ensure that the shape of the profile varies with differing peak/energy ratios in a way that is consistent with the historical load shapes of the last five years. Thus, we have defined F(h) as follows:

$$F(h) = \begin{cases} \dfrac{p-z}{m^2}(m-h)^2 + z \; if \; h \leq m \\ \dfrac{e-z}{(n-m)^2}(h-m)^2 + z \; if \; h > m. \end{cases}$$

Where:

- p denotes the ratio of the underlying peak forecast to the five-year average underlying peak demand
- e denotes the ratio of the underlying expected demand forecast to the five-year average underlying hourly demand
- m denotes the position in the profile in which the curve flattens (1,500 hours for this year’s modelling), as has been observed (on average) in historical years.
- n denotes the total number of hours in a year and
- z represents a curvature constant that is adjusted to achieve the expected demand forecast in the profile’s resulting load shape.

[22] We have assumed that the 90/10% POE peaks occur at the same time as the 50% POE peak.

Repeating this process for each of 10/50/90% POE forecasts gives us hourly underlying demand across the modelling horizon, for each scenario.

2.4.3 Forecasting Hourly DER Contribution:

Our DER forecasts are the sum of the following data:

- BTM PV generation
- BTM battery charging demand and discharge

Each component has a separate methodology which is discussed below. These methodologies produce hourly forecasts which are aggregated together to produce hourly DER contribution for each Capacity Year over the modelling horizon. EVs are already included in the forecasts from AEMO, so we have not modelled these separately. Note that all scenarios use the same DER forecasts.

BTM PV Generation and Outages

The profile of BTM PV generation is complex, with seasonal and daily variability and random intermittency caused by cloud cover. For the purpose of modelling, this can be broken down into:

- Daily generation potential profiles for each month of the year, assuming zero cloud cover (we have assumed that the 99.5% percentile generation in a given month and hour represents a unit generating at its maximum capacity with zero cloud cover). These are deterministic (i.e. fixed and predictable) profiles and are expressed as capacity factors (i.e. fractions of installed capacity).
- BTM PV capacity forecasts (MW) over the modelling horizon.
- An outage probability distribution function (PDF), expressing the probability that a given unit of generation output will be eliminated by cloud cover. This PDF is dependent on the outage (i.e. cloud cover) in the previous hour, and this dependency needs to be factored in to avoid excessive changes in solar PV output from one period to the next. These factors have been developed from historical capacity factors, analysing actual generation compared to forecasted generation and 'adding features' to the PDF as necessary, validating it against historical generation. This dependency is also a function of the season of the year. Therefore, PDFs have been computed for a range of previous hour outage factors and each season (summer, winter, and shoulder).

AEMO has provided historical BTM PV capacity factor data for each trading period from 1 January 2010 to 23 February 2020. Using statistical analysis (comparing actual generation to zero cloud cover generation in a period, and processing this into percentiles) of the historical data, we process daily generation profiles for each month and outage PDF, as described above. AEMO has also provided installed capacity forecasts over the modelling horizon.

The following tables and figures provide the inputs into the PV modelling process:

- Figure 7 shows the BTM PV potential generation factors
- Figures 8 - 10 show the BTM PV outage factor PDFs for each season (Summer, Shoulder, Winter)

Figure 7: BTM PV - potential capacity factors

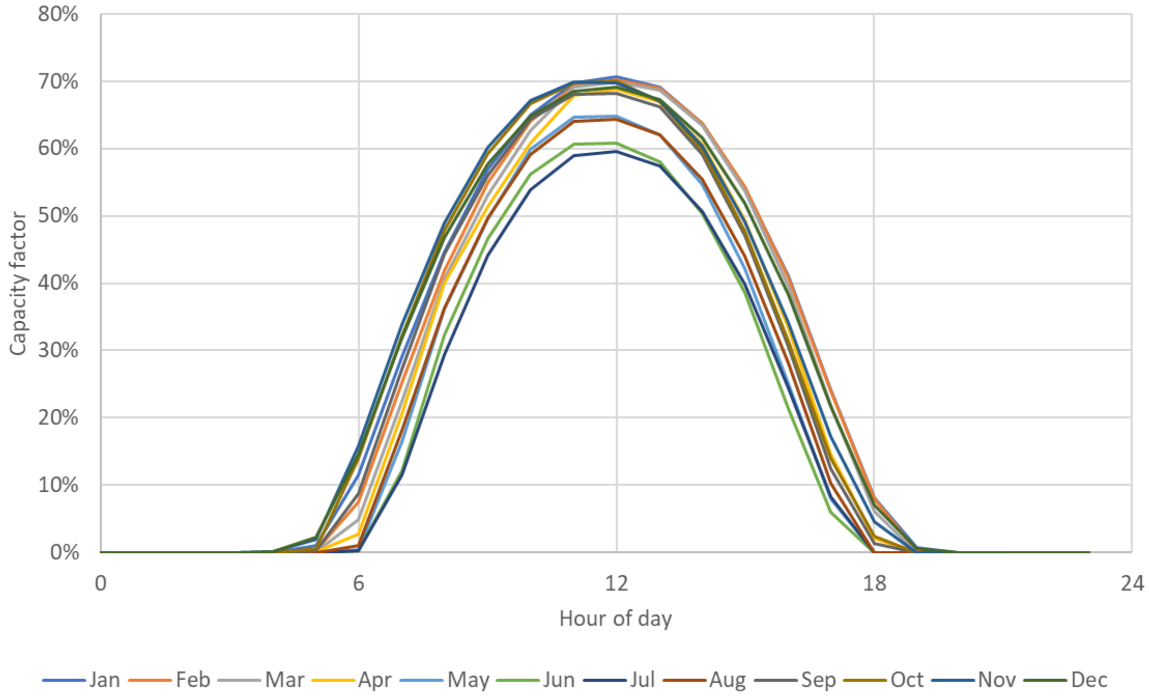


Figure 8: BTM PV - outage factor PDFs (Summer)

	Previous Outage Factor									
Outage Factor	0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
0.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.05	0.2500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.10	0.3333	0.0877	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.15	0.2500	0.1228	0.0598	0.0132	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.20	0.0833	0.3860	0.1538	0.0329	0.0043	0.0000	0.0000	0.0000	0.0000	0.0000
0.25	0.0833	0.2281	0.1880	0.0855	0.0043	0.0035	0.0000	0.0000	0.0000	0.0000
0.30	0.0000	0.1053	0.2735	0.1645	0.0216	0.0104	0.0000	0.0000	0.0000	0.0000
0.35	0.0000	0.0351	0.1453	0.1447	0.0647	0.0174	0.0018	0.0000	0.0000	0.0000
0.40	0.0000	0.0000	0.0598	0.1974	0.1595	0.0451	0.0126	0.0000	0.0000	0.0000
0.45	0.0000	0.0175	0.0598	0.1645	0.1724	0.0660	0.0072	0.0026	0.0000	0.0000
0.50	0.0000	0.0000	0.0513	0.0855	0.1897	0.1285	0.0450	0.0017	0.0000	0.0000
0.55	0.0000	0.0000	0.0085	0.0855	0.1422	0.1354	0.0649	0.0044	0.0003	0.0000
0.60	0.0000	0.0000	0.0000	0.0132	0.1250	0.1910	0.0919	0.0244	0.0006	0.0000
0.65	0.0000	0.0175	0.0000	0.0066	0.0733	0.1840	0.1766	0.0427	0.0019	0.0000
0.70	0.0000	0.0000	0.0000	0.0066	0.0302	0.1285	0.2270	0.0924	0.0075	0.0000
0.75	0.0000	0.0000	0.0000	0.0000	0.0086	0.0625	0.2342	0.1700	0.0180	0.0010
0.80	0.0000	0.0000	0.0000	0.0000	0.0043	0.0208	0.0901	0.2807	0.0652	0.0012
0.85	0.0000	0.0000	0.0000	0.0000	0.0000	0.0035	0.0288	0.2903	0.2336	0.0070
0.90	0.0000	0.0000	0.0000	0.0000	0.0000	0.0035	0.0180	0.0776	0.4908	0.0840
0.95	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0131	0.1780	0.5746
1.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0018	0.0000	0.0040	0.3323

Figure 9: BTM PV - outage factor PDFs (Shoulder)

	Previous Outage Factor									
Outage Factor	0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
0.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.05	0.2500	0.0377	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.10	0.5000	0.0566	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.15	0.0000	0.2264	0.0721	0.0072	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.20	0.2500	0.3019	0.1712	0.0362	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.25	0.0000	0.2075	0.2793	0.0507	0.0217	0.0035	0.0000	0.0000	0.0000	0.0000
0.30	0.0000	0.1132	0.1622	0.1739	0.0326	0.0246	0.0000	0.0000	0.0000	0.0000
0.35	0.0000	0.0566	0.1892	0.1594	0.1033	0.0211	0.0043	0.0000	0.0000	0.0000
0.40	0.0000	0.0000	0.0721	0.2101	0.1304	0.0563	0.0043	0.0000	0.0000	0.0000
0.45	0.0000	0.0000	0.0270	0.1812	0.1576	0.0845	0.0108	0.0022	0.0000	0.0000
0.50	0.0000	0.0000	0.0090	0.0942	0.1957	0.1444	0.0409	0.0077	0.0005	0.0000
0.55	0.0000	0.0000	0.0090	0.0290	0.1413	0.1408	0.0989	0.0187	0.0000	0.0000
0.60	0.0000	0.0000	0.0000	0.0362	0.1522	0.1690	0.0989	0.0529	0.0009	0.0000
0.65	0.0000	0.0000	0.0090	0.0217	0.0326	0.1620	0.2065	0.0562	0.0087	0.0000
0.70	0.0000	0.0000	0.0000	0.0000	0.0217	0.1373	0.2301	0.1103	0.0160	0.0000
0.75	0.0000	0.0000	0.0000	0.0000	0.0109	0.0493	0.1892	0.1830	0.0375	0.0000
0.80	0.0000	0.0000	0.0000	0.0000	0.0000	0.0035	0.0968	0.3142	0.0970	0.0040
0.85	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0129	0.2073	0.2841	0.0198
0.90	0.0000	0.0000	0.0000	0.0000	0.0000	0.0035	0.0065	0.0441	0.4167	0.1323
0.95	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0033	0.1359	0.6005
1.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0027	0.2435

Figure 10: BTM PV - outage factor PDFs (Winter)

	Previous Outage Factor									
Outage Factor	**0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**	**0.8**	**0.9**
0.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.05	0.1636	0.0061	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.10	0.3455	0.0547	0.0111	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.15	0.2909	0.2644	0.0348	0.0021	0.0014	0.0005	0.0000	0.0000	0.0000	0.0000
0.20	0.1273	0.2888	0.0981	0.0126	0.0048	0.0010	0.0000	0.0000	0.0000	0.0000
0.25	0.0545	0.1824	0.1883	0.0547	0.0109	0.0025	0.0000	0.0000	0.0000	0.0000
0.30	0.0182	0.0942	0.2215	0.1232	0.0280	0.0059	0.0030	0.0003	0.0000	0.0000
0.35	0.0000	0.0456	0.1804	0.1663	0.0478	0.0128	0.0034	0.0012	0.0000	0.0000
0.40	0.0000	0.0304	0.1203	0.1947	0.1031	0.0241	0.0086	0.0045	0.0002	0.0000
0.45	0.0000	0.0152	0.0823	0.1684	0.1612	0.0665	0.0132	0.0024	0.0007	0.0000
0.50	0.0000	0.0152	0.0301	0.1168	0.2083	0.1025	0.0365	0.0057	0.0004	0.0000
0.55	0.0000	0.0000	0.0206	0.0926	0.1803	0.1587	0.0609	0.0159	0.0015	0.0000
0.60	0.0000	0.0000	0.0063	0.0389	0.1352	0.2100	0.1177	0.0246	0.0022	0.0000
0.65	0.0000	0.0030	0.0032	0.0200	0.0615	0.1971	0.1880	0.0571	0.0064	0.0009
0.70	0.0000	0.0000	0.0032	0.0063	0.0294	0.1316	0.2237	0.1117	0.0148	0.0006
0.75	0.0000	0.0000	0.0000	0.0032	0.0178	0.0586	0.2038	0.1916	0.0427	0.0025
0.80	0.0000	0.0000	0.0000	0.0000	0.0096	0.0168	0.1045	0.2863	0.0925	0.0057
0.85	0.0000	0.0000	0.0000	0.0000	0.0000	0.0099	0.0248	0.2256	0.2663	0.0220
0.90	0.0000	0.0000	0.0000	0.0000	0.0007	0.0015	0.0105	0.0637	0.4286	0.1111
0.95	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0015	0.0090	0.1388	0.5765
1.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0046	0.2807

These three factors are combined to simulate a realistic solar generation profile by:

1. For each modelled hour, selecting the generation potential value from Figure 7.
2. For each modelled hour, randomly generating an outage factor from the PDFs. This is done by generating a random number for each modelled hour. This random number looks up the cumulative PDF in Figure 8,9,10 for the relevant season, for the relevant previous outage factor, which gives the modelled hour's outage factor.
3. Multiplying these two factors by the forecast MW PV capacity in for the period, to obtain a MWh generation value.

We use five outage seeds to provide a range of potential PV generation sequences. In order to vary BTM PV outages, we simply change the random outage seed and regenerate the random numbers, which then selects a different outage factor (and consequent generation) for each modelled hour. This gives us five varying PV generation sequences. We then take the hourly average of these sequences.

BTM Battery Storage

BTM batteries include installations at domestic and commercial properties, but do not include grid-connected storage Facilities.

From AEMO, we have received MW capacity and MWh duration forecasts by year and month for residential and two classes of commercial batteries (up to 100 kW and above 100 kW).

Normalised historical charge and discharge profiles for residential and commercial batteries, by period and month of year (expressed as a fraction of the installed kW battery capacity) have also been provided by AEMO. We take the charge and discharge profile for each period and month of year, over the last ten years (to align with the PV historical data) to create an average profile for the modelling.

The resulting net charge/discharge for a given period in a model year is calculated as:

$$\begin{aligned} BattNetCD_{y,p} &= 1000 \times \left(Charge_{M(p),p}^{Res} - Discharge_{M(p),p}^{Res}\right) \times BatMW_{c,y,M(p)}^{Res} \\ &+ 1000 \times \left(Charge_{M(p),p}^{Com} - Discharge_{M(p),p}^{Com}\right) \times \left(BatMW_{c,y,M(p)}^{ComSml} + BatMW_{c,y,M(p)}^{ComLge}\right) \end{aligned}$$

Where:

$BattNetCD_{y,p}$	is the net battery charge/discharge for period p in year y
$Charge_{m,p}^{Res}$	is the residential charge profile for month m, period p
$Discharge_{m,p}^{Res}$	is the residential discharge profile for month m, period p
$Charge_{m,p}^{Com}$	is the commercial charge profile for month m, period p
$Discharge_{m,p}^{Com}$	is the commercial discharge profile for month m, period p
$M(p)$	is the number of the month that period p is in
$BatMW_{c,y,m}^{Res}$	is the forecast residential battery capacity in MW
$BatMW_{c,y,m}^{ComSml}$	is the forecast small commercial battery capacity in MW
$BatMW_{c,y,m}^{ComLge}$	is the forecast large commercial battery capacity in MW

This net charge/discharge is a negative value when discharge exceeds charge demand, so reduces the total demand.

2.4.4 Creating the Preliminary Operational Load Profile

In order to create the preliminary operational load profiles for each scenario, we first aggregate our hourly underlying load forecasts with our hourly DER contribution forecasts (which are the same in each scenario) to create hourly delivered (non-loss adjusted) load forecasts, such that:

$$DL_d = UL_d - DER_d$$

Where DL_d refers to the delivered load at datetime d, UL_d refers to the underlying load forecasts and DER_d refers to the hourly DER contributions. The delivered loads are then loss-adjusted by a weighted loss factor, calculated from a residential loss factor (1.0472) and a business loss factor

(1.0346) provided by AEMO[23], and the relative proportion of forecasted underlying residential to business annual demand, such that:

$$OL_d = DL_d \times \left(\left(LF_r \times \frac{L_r}{L_r + L_b} \right) + \left(LF_b \times \frac{L_b}{L_r + L_b} \right) \right)$$

Where OL_d refers to the operational load at datetime d, LF_r, LF_b refers to the residential and business loss factors (respectively), and L_r,L_b refers to total forecast underlying residential and business load/demand for a given Capacity Year.

These preliminary operational load hourly forecasts are then aggregated into the operational load profile for each Capacity Year by:

- Converting the load values into a load shape by expressing each load value as a percentage of maximum demand, ranking these in descending order (largest to smallest).
- Indexing the load shape by its associated date in the hourly forecasts to create a load chronology.

This give us a preliminary operational load profile for each forecast Capacity Year and scenario.

2.4.5 Scaling the Operational Load Profile to Forecasted Values

In some cases, the derived operational peak and annual energy demands from our forecasts may not exactly match the forecasts provided by AEMO. This is for three reasons:

- The 10/50/90% peak demands provided by AEMO do not necessarily match the expected annual energy demands, as these may reflect different underlying demand conditions.
- The methodology used by AEMO to create the 10/50/90% POE forecasts relies on many iterations of BTM PV generation, the likelihood of one of our PV outage sequences exactly corresponding with AEMO's is low.
- The methodology used in forecasting battery charge/discharge by AEMO in producing their forecasts is not exactly reproducible by RBP, as it is a function of the PV simulations.

In order to ensure that the operational peaks from our forecast match AEMO's, we re-scale the operational load profiles created in Section 2.4.4, using the function described in Section 2.4.2. This give us hourly load forecasts that capture year-on-year variation in load shape and chronology, while maintaining alignment with the forecasts provided by AEMO.

[23] From https://aemo.com.au/-/media/files/electricity/wem/data/loss-factors/2019/2019-20-loss-factor-report.pdf?la=en. Residential: page 14, Distribution System Wide Average Loss Factor applied in 2018/19. Business: page 8, Transmission SWIN Average Loss Factor applied in 2018/19.

2.5 Fuels

Fuel prices are specified in Real 2020[24] AUD terms, so the market prices produced by the model are also in Real 2020 AUD terms. Fuel costs for fuels not listed in this section (landfill gas, waste, etc.) are assumed to be zero across all years.

2.5.1 Pipeline Natural Gas

The prices for pipeline natural gas (for a base, low and high scenario) have been provided by AEMO for the purpose of this analysis.

2.5.2 Coal

Coal-fired generators in WA receive coal directly from WA coal mines under a contract between the mining companies and the WA government. The terms of this contract are not public, so the cost of this coal needs to be estimated for modelling purposes.

WA coal is not exported beyond WA, so does not receive global market prices.

Data on the value of WA coal is provided in the *2019 Major Commodities Resources Data*, published by the Government of Western Australia Department of Mines, Industry Regulation and Safety[25]. This provides data on the quantity and value of coal produced in WA. Assuming a calorific value of 19.7 GJ/t[26], this yields the following historical prices:

Table 6: Coal price results from published statistics

Financial Year	Volume(t)	Value (AUD)	Nominal AUD/t	Nominal AUD/GJ	Real 2020 AUD/GJ
2014-15	6,553,064	306,733,911	46.81	2.38	2.58
2015-16	6,890,951	336,466,825	48.83	2.48	2.66
2016-17	6,806,389	338,435,045	49.72	2.52	2.65
2017-18	6,679,935	331,959,622	49.70	2.52	2.60
2018-19	6,275,190	319,370,156	50.89	2.58	2.62
5-Year Average:					2.62

Based on these results, we have used a constant price (in Real 2020 AUD terms) of AUD 2.62/GJ.

[24] Coal and distillate prices have been inflated from 2019 AUD to 2020 AUD, using an annual inflation rate of 1.5%.

[25] https://www.dmp.wa.gov.au/About-Us-Careers/Latest-Statistics-Release-4081.aspx

[26] Guide to the Australian Energy Statistics 2017: https://www.energy.gov.au/sites/default/files/guide-to-australian-energy-statistics-2017_0.docx

2.5.3 Distillate

Historical "Perth Terminal Gate" prices for distillate (i.e. Diesel) are available from the Australian Institute of Petroleum[27]. Diesel prices are strongly correlated with global (e.g. Brent) crude oil prices, and a linear correlation can be obtained based on historical diesel and crude oil prices. By applying this correlation to the crude oil forecast, a distillate price forecast has been obtained as provided in Table 7.

Table 7: Distillate price forecast

Calendar Year	Price (Real 2020 AUD/GJ)
2020	20.59
2021	21.15
2022	22.06
2023	23.74
2024	25.17
2025	25.82
2026	26.70
2027	27.55
2028	28.16
2029	28.72
2030	29.16

The following parameters are also assumed in this forecast:

- Excise tax (currently 0.423 c/l) and GST (10%) are rebated
- Calorific value is 38.6 MJ/l[28]
- Transport cost to Parkeston area is 1.1 c/l[29]

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[27] https://www.aip.com.au/pricing/terminal-gate-prices/perthDiesel

[28] Page 318 of the National Greenhouse and Energy Reporting (Measurement) Determination 2008: https://www.legislation.gov.au/Details/F2019C00553/6a96c1f2-5a98-4edc-a2c0-769253a56017

[29] AEMO 2020 Energy Price Limits Review: https://aemo.com.au/en/consultations/current-and-closed-consultations/2020-energy-price-limits

2.6 Ancillary Services

In all years we have modelled four Ancillary Services, as set out in Table 8 below:

Table 8: Modelled Ancillary Services and requirements

Ancillary Service	Requirement[30]
Spinning Reserve (SR)	70% of the largest generating unit
Load Rejection Reserve (LRR)	90 MW
Load Following Ancillary Service Up (LFAS Up)	105 MW (5:30 AM - 7:30 PM) 80 MW (7:30 PM - 5: 30 AM)
Load Following Ancillary Service Down (LFAS Down)	105 MW (5:30 AM - 7:30 PM) 80 MW (7:30 PM - 5: 30 AM)

We note that there is currently reform work under way defining new Ancillary Services (AS) that may be required in the future. As it is still unclear what those services may look like and how they may be procured, we assume that the above quantities will remain in force. AEMO has provided AS capability assumptions for each generator pre- and post-reform.

2.7 Scenario Definitions

In consultation with AEMO, we have developed a range of scenarios to be modelled for the GPG forecast study, as specified in Table 9. We have used low gas prices for the High scenario and high gas prices for the Low scenario (as high gas prices in the High scenario would make GPG less competitive and vice-versa).

30 Source: https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/aemos-ancillary-services-requirements

Table 9. Scenario definitions

Scenario	High	Base	Low
Operational consumption[A]	High	Expected	Low
Peak demand[A]	High case - 10% probability of exceedance (POE)	Expected case - 50% POE	Low case - 90% POE
Gas price[B]	Low	Expected	High
Behind the meter PV and battery storage[A]	Expected	Expected	Expected
Generation retirements	Staged retirement of Muja C: • MUJA_G5 retires 1 October 2022. • MUJA_G6 retires 1 October 2024.		
Generation new builds	• Phoenix Kwinana 1 October 2021 • East Rockingham Resource Recovery Facility 1 October 2022		

[A] Sourced from the 2020 WEM ESOO.

[B] Sourced from Energy Quest.

3 Summary of Modelling Results

In this section we provide a summary of the key modelling results. Full modelling results, down to an hourly time resolution, have been provided to AEMO in spreadsheet form.

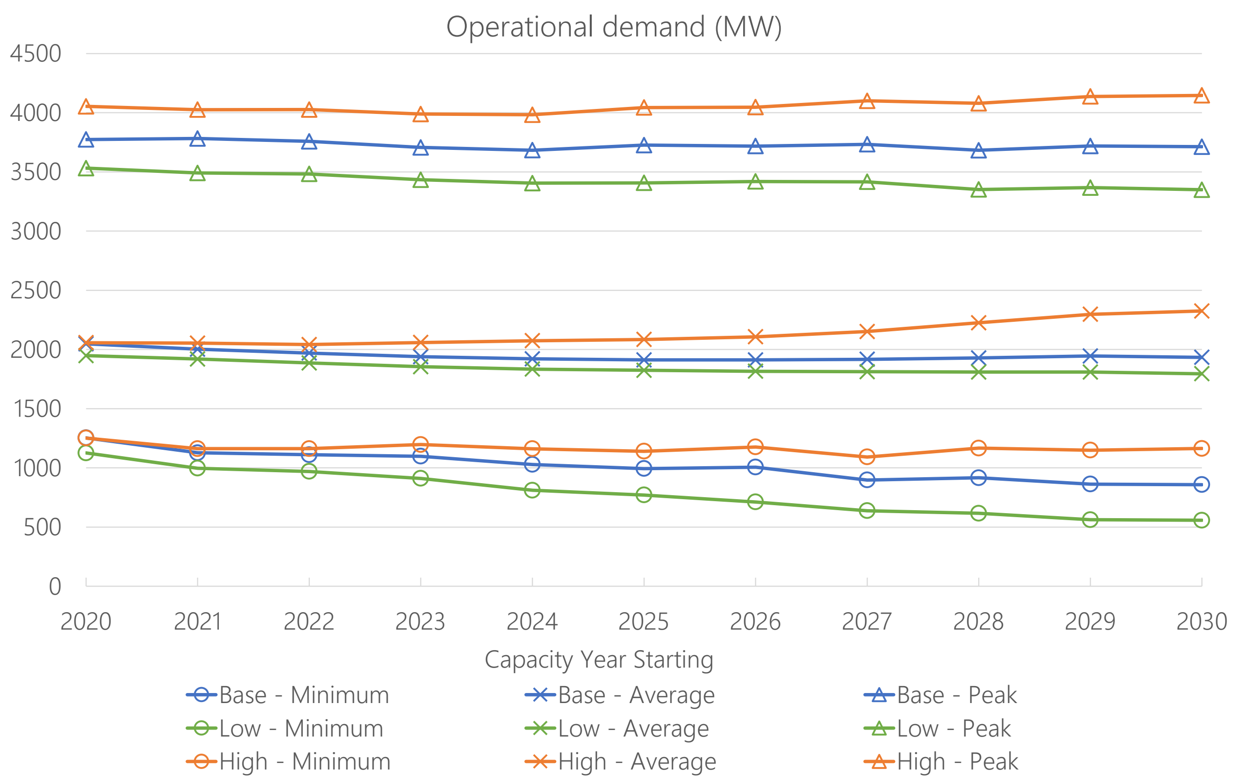
In the following sections, we provide summaries of the following results on an annual basis:

- Operational demand
- Gas consumption
- Coal consumption
- Carbon emissions

3.1 Operational Demand

Figure 11 shows the hourly average, peak and minimum demand for each Capacity year in the modelling horizon.

Figure 11: Minimum, average, and peak operational demand



There is a much larger spread between demand scenarios in this year's modelling when compared to last year. In particular:

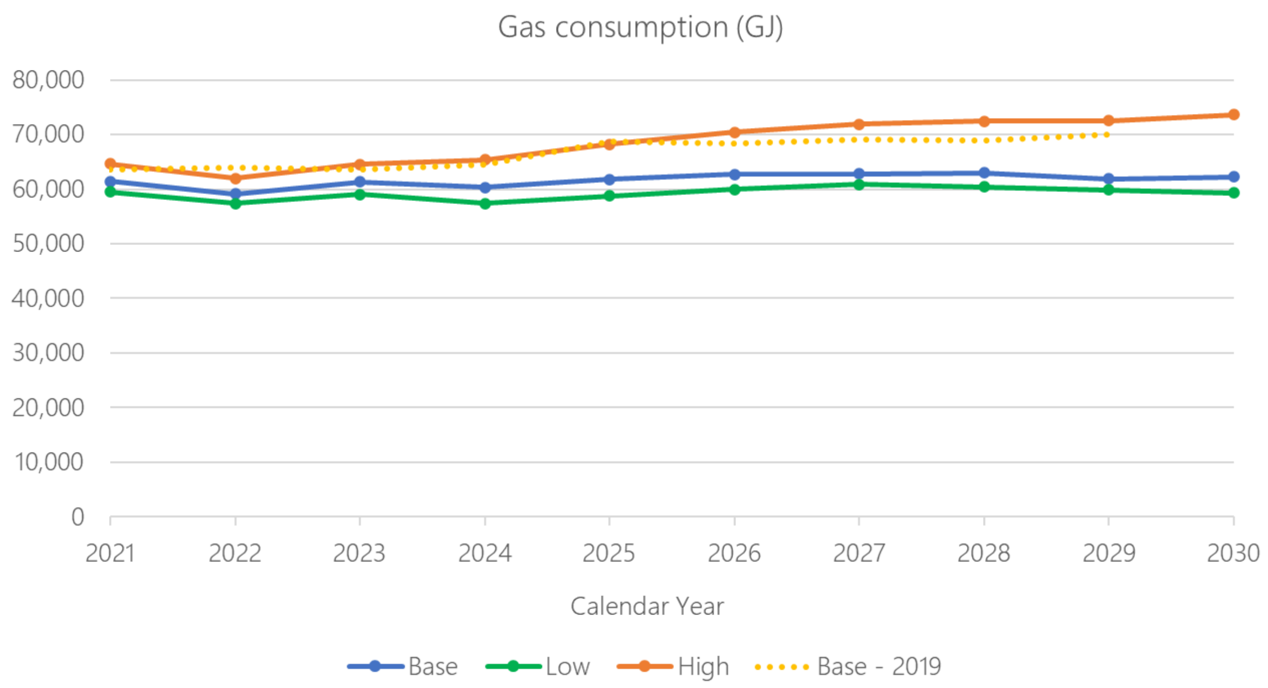
- There is a large increase in average operational demand in the High scenario. Notably, while the annual operational demands of the Base/Low scenarios are decreasing or flat over the modelling horizon, the High scenario is 13% higher in the 2030-31 Capacity Year than in 2020-21.
- There are large differences in peak demands between the three scenarios. This is due to our load forecasts using different POE peaks for each scenario (See Section 2.4)
- Minimum demand is lower in the 2030-31 Capacity Year than in 2020-21 for all scenarios. However, for the Base and High scenarios, the load remains above the operational stability constraint. Note that minimum demand forecasts produced by AEMO for the 2020 WEM ESOO have not been reflected in our forecast this year due to changes in AEMO's forecasting methodology[31].

3.2 Gas Consumption

Figure 12 shows the annual total gas consumption from GPG from the model results (on a calendar year basis). Base gas consumption from the 2019 GPG forecasts is included for comparison.

[31] Changes to AEMO's forecasting of electric vehicles (EVs) and large industrial loads (LILs) (similar to block loads in the 2019 GPG report) have meant we are unable to capture these elements of demand separately from underlying demand, which has restricted our ability to reflect AEMO's minimum demand forecasts. LILs in particular, can have a large impact on minimum demand where multiple loads are on outage (i.e. not contributing to demand) in already low demand periods.

Figure 12: Gas consumption



Gas consumption in the Base scenario is lower than the 2019 Base scenario, with the 2019 result more closely resembling the High scenario from this year's modelling. This is due to a combination of higher gas prices, increased renewable generation and lower operational peak demands and energy consumptions in the modelling assumptions this year.

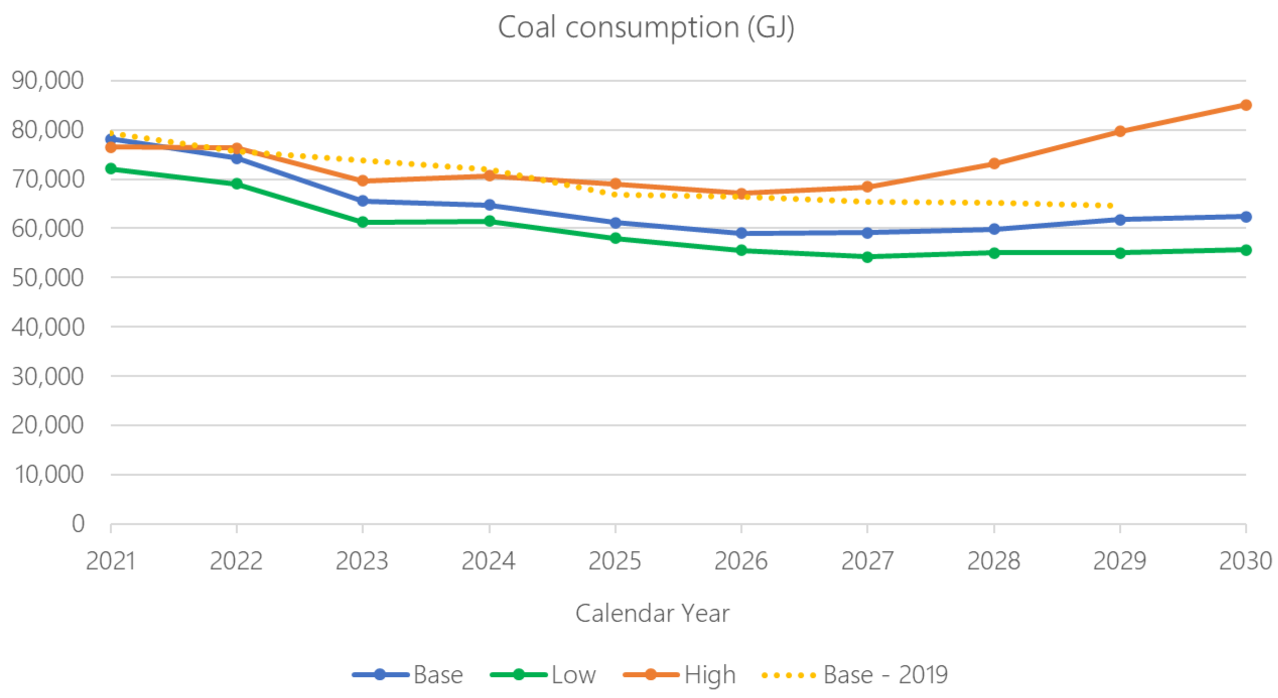
Consumption is relatively flat in the Base/Low scenarios with slight increases in 2023 and 2025 following the retirements of Muja G5 (1/10/2022) and G6 (1/10/2024).

There are relatively large differences between the High and Base/Low scenarios with the High scenario having higher gas consumption from the beginning of the modelling horizon and steady growth from 2023 onwards. This is driven by lower fuel prices and higher operational demands which grow over the modelling horizon.

3.3 Coal Consumption

Figure 13 shows the annual total coal consumption for electricity generation from the model results.

Figure 13: Coal consumption



In all scenarios, coal consumption decreases over the first half of the modelling horizon. The increase in average operational demand for the High scenario drives higher coal consumption from 2027 onwards.

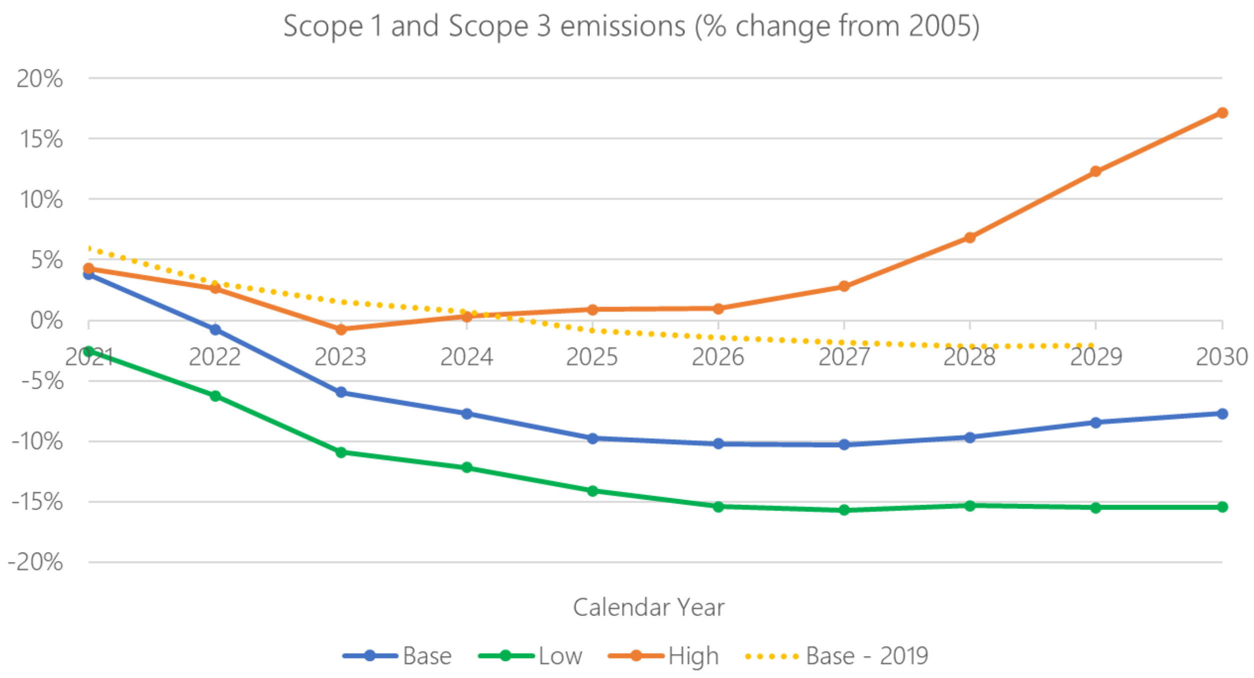
In the Low scenario, coal consumption is decreasing or flat across the entire horizon. In the Base scenario, there is a slight uptick in coal consumption in 2029, due to increasing gas prices.

3.4 Emissions

Figure 14 shows total annual Scope 1 and Scope 3 emissions from the modelling results, in terms of the percentage change from 2005 levels (positive percentage values showing higher emissions than 2005 levels, negative values showing lower emissions).

The emissions presented here are the direct (Scope 1) and indirect (Scope 3) emissions from the combustion of fuels to generate electricity, so do not include emissions related to the use of electricity, nor the construction or decommissioning of generation plants.

Figure 14: Emissions



In all three scenarios, emissions drop in the first three years of the modelling horizon, leading to all scenarios having lower emissions in 2023 than in 2005.

For the High scenario, emissions begin to slowly increase from 2024 onwards and greater coal consumption leads to steep increases in emissions from 2027 onwards.

In both the Base/Low scenarios, emissions decrease quickly until 2024 and then level out from 2025 onwards. There is a slight uptick in Base scenario emissions in 2029, reflecting slightly increased coal consumption.

4 Conclusions

4.1 Key Insights

The following key insights can be drawn from this analysis:

- Gas consumption for the Base/Low scenarios has decreased from last year due to higher fuel prices for the base scenario and lower operational energy consumption.
- Operational peak demand and energy consumption has a large impact on gas consumption. As the spread of the 2020 WEM ESOO forecasts is larger this year (especially the High scenario), we have greater differences between scenarios when compared to last year's modelling.
- None of the three scenarios presented here result in emissions reductions that approach the Australian government target of 26-28%[32] reductions by 2030 under the Paris Agreement. Meeting this target will require measures such as further coal plant retirements and significant increases in renewable generation, both of which will significantly impact gas demand for GPG.

32 https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Australia%20First/Australias%20Intended%20Nationally%20Determined%20Contribution%20to%20a%20new%20Climate%20Change%20Agreement%20-%20August%202015.pdf

GLOSSARY

Table 10 presents a glossary of the terms used in this report:

Table 10: Glossary

Term	Definition
Behind-the-meter	PV and battery systems that produce energy and are connected at a customer's premises. Behind-the-meter PV capacity includes both residential and commercial PV that is less than 100 kilowatts (kW) and commercial PV systems ranging between 100 kW and 10MW
Capacity Credit	A notional unit of Reserve Capacity provided by a Facility during a Capacity Year, where each Capacity Credit is equal to 1 MW of capacity
Capacity Year	A period of 12 months commencing on 1 October and ending on 1 October of the following calendar year
Intermittent generator	A generator that cannot be scheduled because its output level is dependent on factors beyond the control of its operator (e.g. wind speed).
Long Term Projected Assessment of System Adequacy (LT-PASA)	A study conducted in accordance with clause 4.5 of the WEM Rules to determine the Reserve Capacity Target for each year in the Long Term PASA Study Horizon and prepare the WEM ESOO.
Long Term PASA Study Horizon	The 10-year period commencing on 1 October of Year 1 of a Reserve Capacity Cycle.
Load chronology	The chronology of a year (periods), ranked by magnitude of load (i.e. 1 is the peak period), sorted into chronological order.

Term	Definition
Load shape	Hourly load data for a year (expressed in percentage of peak demand), in descending order of magnitude.
Operational demand	Operational demand refers to network demand, met by utility-scale generation, and excludes demand met by behind-the-meter PV generation
Probability of exceedance (POE)	The likelihood of a forecast being exceeded. For example, a 10% POE forecast is expected to be exceeded once in every 10 years.
Reserve Capacity Cycle	A four-year period covering the cycle of events described in clause 4.1 of the WEM Rules.
Underlying demand	Operational demand plus an estimation of behind-the-meter PV generation and the impacts of battery storage. Due to the small uptake of battery storage to date, for historical values the impact of behind-the-meter battery is assumed to be negligible.