ROBINSON BOWMAKER PAUL

AUSTRALIAN ENERGY MARKET OPERATOR

GAS POWERED GENERATION FORECAST MODELLING 2022 - FINAL REPORT

9 December 2022

Prepared by: Richard Bowmaker

Document version: FINAL

Robinson Bowmaker Paul
Level 8
104 The Terrace
Wellington 6011
New Zealand
rbp.consulting

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 in WA is the amount of gas-powered generation (GPG) which is expected to be dispatched over this horizon.

AEMO has engaged Robinson Bowmaker Paul (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 (2023 - 2032).

Methodology and Assumptions changes

All input assumptions have been reviewed, and a large number of updates and refinements have been made relative to the assumptions used for the 2021 GPG modelling. Key changes having a significant effect on the results include:

- Updated demand assumptions in line with the 2022 ESOO forecasts
- Updated fuel price assumptions
- Coal facility retirements in line with WA government announcements
- Additional Bluewaters retirement assumed in Base and High scenarios
- Additional new build assumed in High scenario
- Modelling of current coal supply constraints in Base and High scenarios
- Benchmarking of facility generation against recent SCADA data

The methodology employed is largely consistent with previous years, with the exception that hourly demand forecasts are now based on three recent historical capacity years' load profiles, rather than an average of 5 historical years' load profiles. Consequently, there are three sets of results for each scenario, representing the three base year load shapes.

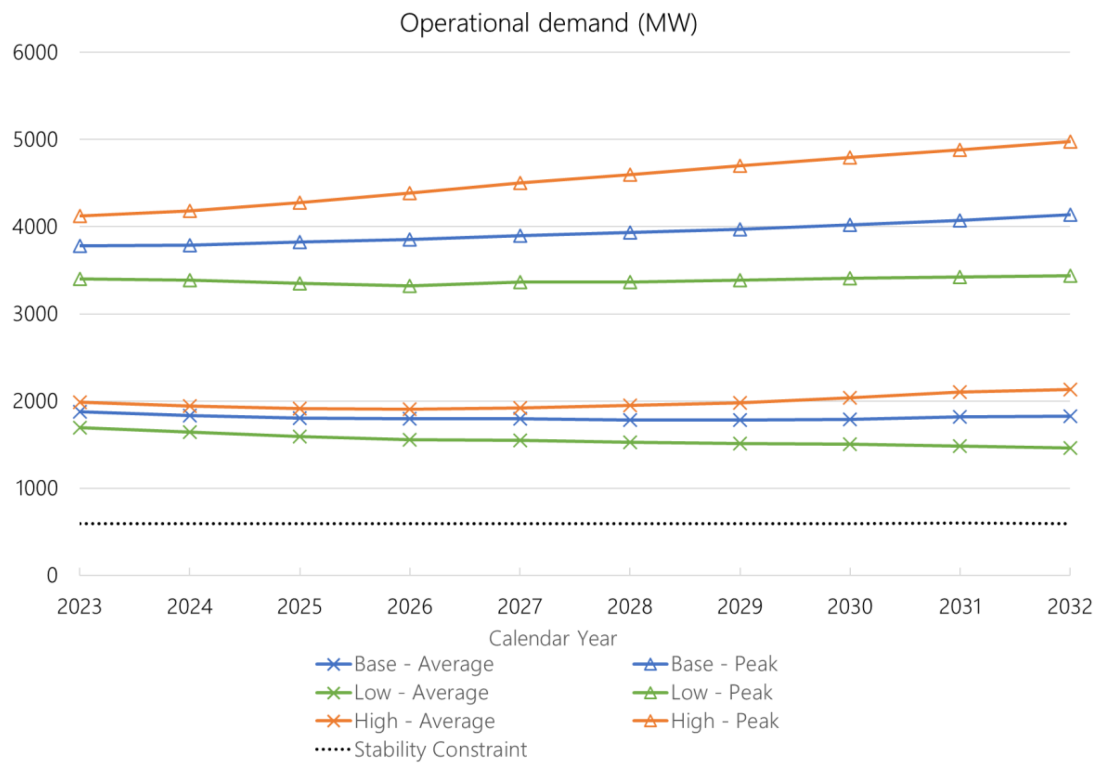
[1] See https://www.wa.gov.au/organisation/energy-policy-wa/gas-services-information.

RESULTS

Operational Demand

Figure 1 shows the hourly average and peak demand for each calendar year in the modelling horizon.

Figure 1: Average and peak operational demand



Relative to the 2021 GPG modelling demand assumptions, the following differences are significant:

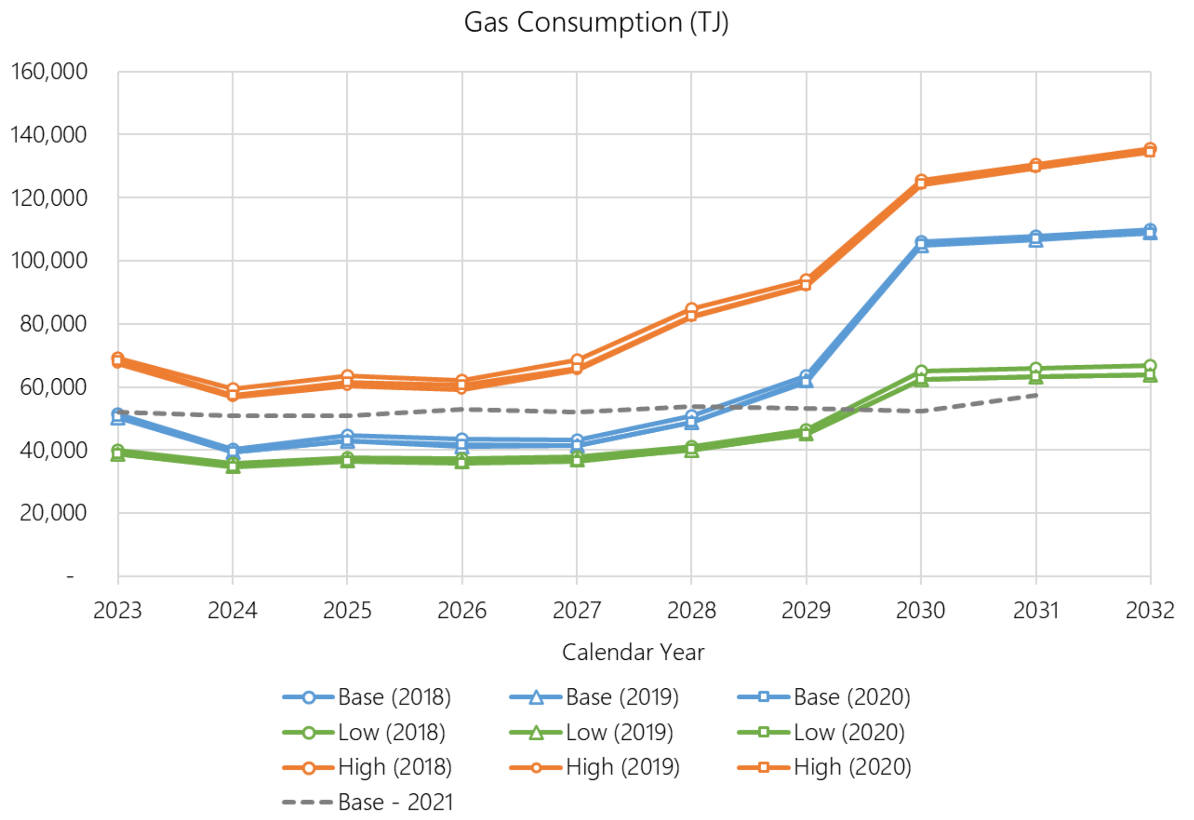
- Average demand is similar
- Peak demand is higher

Gas Consumption

Figure 2 shows the annual total gas consumption from GPG from the model results (on a calendar year basis). Base gas consumption from the 2021 GPG forecasts is included for comparison.

Results are shown for each of the base, high and low scenarios (see section 2.8) and each of the 3 base load profiles (see section 2.4).

Figure 2: Gas consumption



Compared to the 2021 GPG modelling results, Base scenario gas demand is lower for the first 6 years of the outlook horizon. This is the result of a combination of factors:

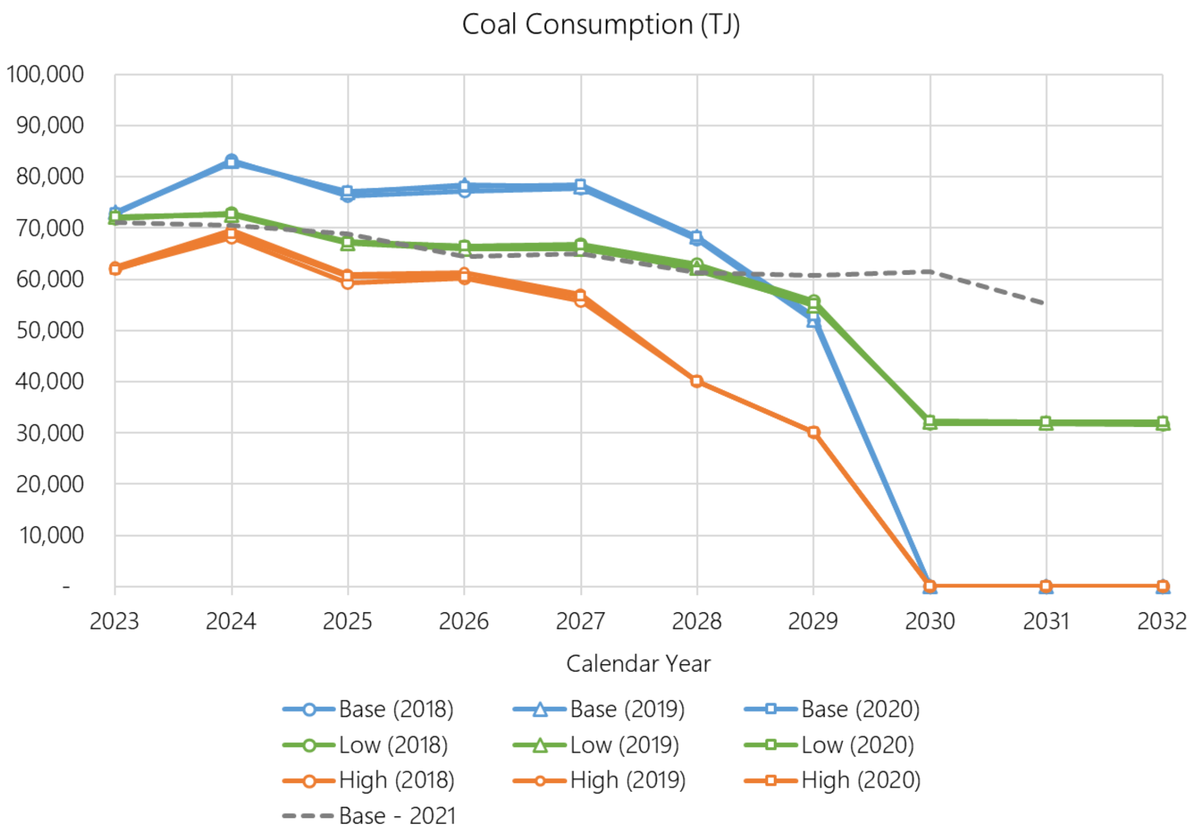
- Increased DER forecasts
- Lower mid-day demand
- Refinement of generator offer assumptions

For the final 4 years of the outlook horizon, Base scenario gas demand is significantly higher. This is mainly due to the additional retirements of the coal plants, relative to the 2021 forecast.

Coal Consumption

Figure 3 shows the annual total coal consumption for electricity generation from the model results.

Figure 3: Coal consumption



Compared to the 2021 GPG modelling results, Base scenario coal demand is higher for the first 6 years of the modelling horizon, driven by lower gas generation. Following that, coal use drops dramatically, following the retirements of the coal units.

The scenario results are not in a Low-Base-High order, and cross over each other for the following reasons:

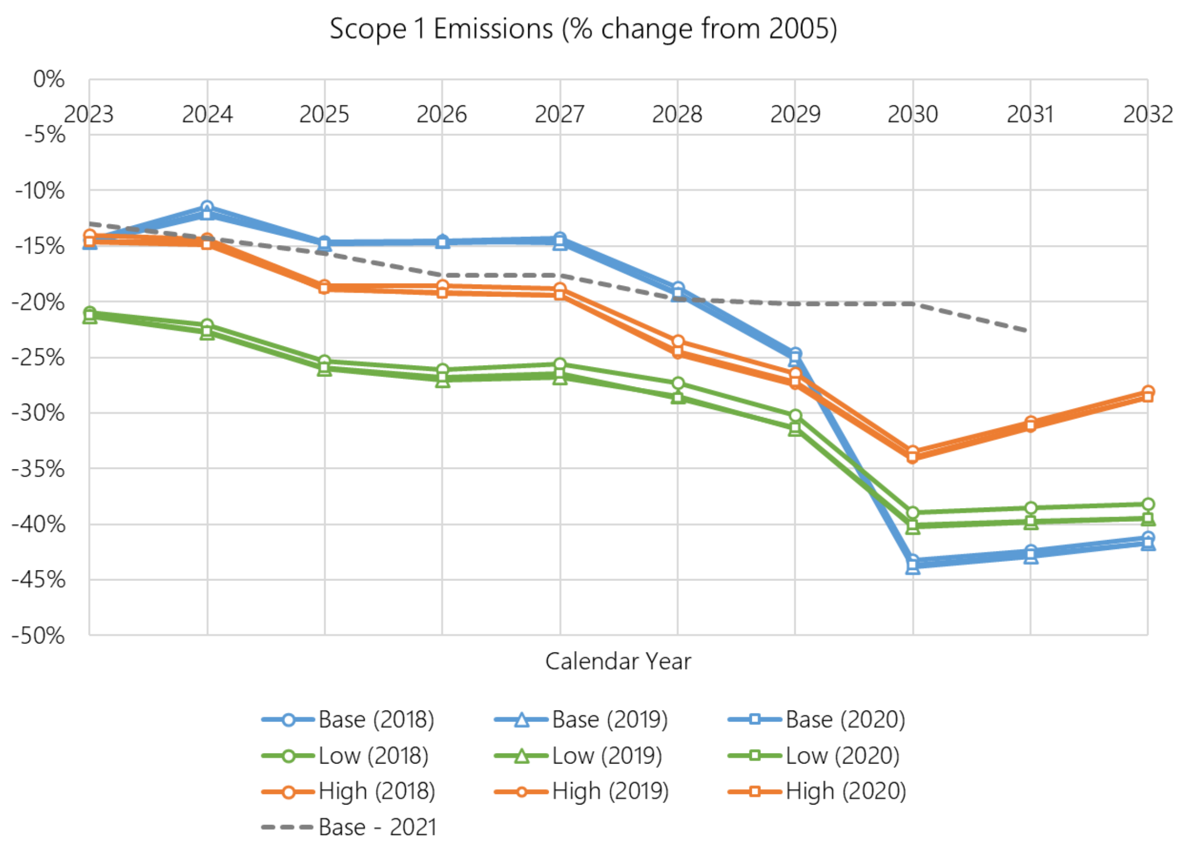
- The High scenario has significant levels of non-coal new build that are not in the other scenarios (see section 2.2.5). This new capacity competes with coal generation, resulting in lower coal consumption.
- The Low scenario does not have the current coal supply constraints applied (see section 2.2.10), so does not experience the dip in coal generation in 2023 that is seen in the Base and High scenarios

By 2030, both the High and Base scenarios have no remaining coal generation capacity due to retirement assumptions (see section 2.2.3). Therefore, coal consumption drops to zero in these scenarios. In the Low scenario, there is still coal consumption as the Bluewaters units do not retire.

Emissions

Figure 4 shows total annual Scope 1 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).

Figure 4: Emissions



Relative to the 2021 GPG modelling results, Base scenario emissions are initially increased, due to the higher coal generation. With the retirement of the coal plant, emissions reduce significantly to be much lower than the 2021 forecasts.

Similarly to the coal consumption results, the scenario results are not in a Low-Base-High order, and cross over each other for the following reasons:

- The High scenario has significant levels of renewables new build that are not in the other scenarios (see section 2.2.5). This new renewable capacity reduced emission to below the base case emissions.
- The retirement of the Bluewaters units at the end of 2029 in the Base scenario reduces emissions from 2030 onwards to below the Low scenario, which still has these units

operating. In the high scenario, this retirement occurs earlier resulting in lower emissions, but this is offset by the emissions from higher gas consumption.

Key Insights

The following key insights can be drawn from this analysis:

- The most significant factor affecting results relative to the 2021 forecasts is the retirements of the coal plants. This has the effect of:
    - Increasing gas consumption
    - Decreasing coal use
    - Reducing emissions
- Higher DER generation assumptions and lower mid-day demand have resulted in a lower base scenario gas use forecasts than the previous year's modelling before the impact of the coal retirements outweighs this effect.
- The Low scenario is the only scenario that meets the Australian Government's newly decreased emissions reduction target of 43% by 2030. This is driven by lower demand levels, which impact coal generation. The base scenario achieves 39-40% reductions. All scenarios have significantly lower emissions by 2030, due to coal plant retirements.

Contents

1 INTRODUCTION

1.1 PROJECT BACKGROUND

The Gas Services Information (GSI) Regulations[2] require AEMO to produce a Gas Statement of Opportunities (GSOO) report on an annual basis. The GSOO must include a forecast of gas demand over a 10-year calendar horizon. One of the key drivers of gas demand is the amount of gas-fired generation which is expected to be dispatched over this horizon.

AEMO has requested RBP to forecast gas demand from Gas-Powered Generation (GPG) in the SWIS over a 10-calendar year horizon (2023 – 2032).

AEMO has requested the analysis consider the following in scope:

- Forecast of gas demand from GPG over a 10-calendar year horizon.

The forecast is to be produced for each of three gas demand scenarios:

- Low
- Medium
- High

The above scenarios are to be based on a combination of varying assumptions for the following inputs:

- Gas prices
- Demand (annual energy)
- Peak demand
- Distributed Photo-voltaic (DPV) and distributed battery storage generation

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,

[2] https://www.wa.gov.au/government/document-collections/gas-services-information-rules

- Key insights and observations, and
- An assessment of limitation and gaps of the modelling methodology and results.

2 FINAL METHODOLOGY AND ASSUMPTIONS

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.

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 2022 Reliability Assessment[3],
- Publicly available data from AEMO and other sources, and
- RBP's own knowledge and insights.

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, VOM, FOM)
- Transmission data, either via the specification of thermal limits of generic constraints (as used in the NEM and for the WEM SCED)
- Reserve requirement and provision data.

WEMSIM outputs can include (but is not limited to):

- Fuel use by generators
- Hourly energy dispatch and reserve provided
- Locational price forecasts (i.e., nodal prices)
- Capacity utilisation of generation facilities
- Revenues earned and costs incurred by facility and participant
- Emissions.

[3] See https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2022/2022-aemo-reliability-assessment---rbp.pdf?la=en

2.2 GENERATORS

In this section we set out our assumptions around:

- The technical parameters and operational costs of:
  - Existing generation Facilities, and
  - New generation Facilities that will come online during the 10-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[4] have been taken from the publicly available AEMO Costs and Technical Parameter Review, completed in 2018-19 by GHD[5], and refined during the 2019, 2020, and 2021 GPG modelling assignments.

2.2.2 Seasonal capacity variation

Seasonal capacity variations have been supplied by AEMO and implemented in the model.

2.2.3 Retirements

On 15 June, the WA government announced the retirement of all Synergy coal facilities by 2030, and no new gas fired facilities from 2030. Based on this, the following retirements are assumed to occur during the modelling horizon:

Table 1: Retirement schedules – All Scenarios

Unit	Retirement Date
MUJA_G6	1 October 2024
COLLIE_G1	1 October 2027
MUJA_G7	1 October 2029
MUJA_G8	1 October 2029

[4]We have not modelled the dispatch of Network Control Service generators (Mungarra and West Kalgoorlie)

[5] Available from https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies

Once speculative conclusion that could be reached based on the above retirements is that the Collie coal mines will become uneconomic as a result of the above retirements, and as a consequence the remaining Bluewaters coal plant will also retire. We will assume this situation for the Base and High scenarios:

Table 2: Additional retirements – Base Scenario

Unit	Retirement Date
BW1_BLUEWATERS_G2	1 October 2029
BW2_BLUEWATERS_G1	1 October 2029

Table 3: Additional retirements – High Scenario

Unit	Retirement Date
BW1_BLUEWATERS_G2	1 July 2023
BW2_BLUEWATERS_G1	1 July 2023

2.2.4 New Build

There are some new generators coming online during the 10-year modelling horizon. These facilities are included in all scenarios.

2.2.5 Additional new build for High scenario

Additional new build, identified from AEMO's 2021 Expression of Interest (EOI) process, will be included in the high scenario only.

In addition, a number of facilities receive capacity upgrades in the High scenario.

Generic new build

If the modelling results indicate that new build is required in addition to the specific facilities specified in this section, generic new build would be added according to the following methodology. In the final modelling result, generic new build was not required.

- Candidate new build Facilities will be chosen from the following options:
  - OCGT
  - CCGT
  - Biomass
  - Large scale Solar PV
  - Solar Thermal (8hrs Storage)
  - Battery storage (2hrs storage)

- Battery Storage (4hrs storage)
- Wind

Each suitable candidate will be modelled separately, and the economic viability of the new build will be assessed according to the capital costs and operating parameters used in the development of the 2019-2020 and 2020-2021 AEMO Integrated System plans (ISPs)[6], as summarised in Table 4.

The most profitable option will be chosen for the final scenario run.

Table 4: Generic new build parameters (Real 2021 AUD/kW)[7]

Technology Type	Build Time (yrs)	Econ - omic Life (yrs)	Technical Life (yrs)	FOM ($/kW/ annum)	VOM ($/MWh sent out)	Heat Rate (GJ/MWh HHV s.o.)	Auxiliary Load (%)
OCGT	1.3	25	50	12.6	12.0	10.19	1.70
CCGT	1.5	25	40	10.9	3.7	7.25	2.50
Biomass	1.3	30	50	131.6	8.4	13.74	8.30
Large scale solar PV	0.5	30	30	17.0	0.0	n/a	0.20
Battery storage (2hrs storage)	1	20	20	10.80	0.0	n/a	0.00
Battery storage (4hrs storage)	1	20	20	17.25	0.0	n/a	0.00
Wind	1.0	25	30	25.0	0.0	n/a	0.28
Solar Thermal	1.8	25	40	120.0	0.0	n/a	10.00

[6] For the 2020-2021 ISP, some parameters were only provided by regions, not including WA, so these parameters remain the same as last year.

[7] Connection cost from 2021 NEM planning and forecasting input assumptions and the rest from GenCost 2021-22.

Table 5. Generic new build connection costs

Size of Facility	Connection Cost (Real 2021 AUD/kW)
0 – 10 MW	10
10 – 100 MW	65
>100 MW	185

Table 6: Generic new build capital costs (Real 2021 AUD/kW)

Technology Type	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
OCGT (small)	1290	1290	1287	1285	1282	1280	1277	1275	1272	1270
CCGT	1559	1559	1556	1553	1550	1547	1543	1540	1537	1534
Biomass	6954	6954	6954	6954	6954	6954	6954	6954	6954	6954
Large scale solar PV	1441	1441	1382	1331	1286	1244	1203	1171	1142	1102
Battery storage (2hrs storage)	1032	1006	990	980	972	960	928	900	890	860
Battery storage (4hrs storage)	1628	1584	1556	1544	1528	1512	1456	1400	1388	1332
Wind	1805	1797	1776	1756	1739	1724	1711	1701	1691	1673
Solar Thermal	6,693	6,693	6,581	6,476	6,333	6,191	6,035	5,894	5,771	5,660

2.2.6 Utility-Scale Intermittent Profiles

Treatment of intermittent generation

We have reapplied the methodology used in the 2022 Reliability Assessment[8] to derive intra-day hourly profiles for each month for each intermittent utility-scale facility[9]. This has resulted in 12 intra-day profiles for each of the 29 intermittent Facilities.

For new build (as specified in section 2.2.4) that is intermittent, profiles from the nearest comparable existing facility were used.

2.2.7 Outages

Forced outages

We will use the forced outage assumptions developed for the 2022 Reliability Assessment. These were developed from 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 will be unrealistic as equipment is unlikely to have a zero-failure rate over the ten-year modelling horizon.

---

[8]This was as follows:

- For each month (Jan, Feb, …, Nov, Dec), we assign an intra-day hourly profile to each intermittent generator.
- Each intermittent generator will have 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:

o $\overline{Gen_{h,m}}$ denotes the average generation (MW) in hour h of month m (based on T years of historical or participant provided generation values)

o $Gen_{Y,h,d}$ denotes the historical or estimated generation value in hour h or day d (in month m) of Year Y.

[9] Profiles of existing intermittent generation were derived using historical non-loss adjusted metered quantities. Profiles for new intermittent generation were derived using participant provided estimated generation (which AEMO provided RBP to conduct the 2022 Reliability Assessment).

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 off their 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.

Planned outages

As part of the 2022 Reliability Assessment, AEMO provided RBP with participant provided planned outage schedules from 2023 to the end of 2032. We reused these for the GPG forecasting (zeroing out the relevant facilities' capacity on dates where a participant has indicated an outage), supplemented with approved upcoming planned outage data supplied by AEMO.

2.2.8 Emissions Factors

The quantity of carbon emissions resulting from electricity generation will be calculated in WEMSIM, based on emission factors published by AEMO for existing and new generators in the SWIS[10].

2.2.9 Operational Stability Constraint

AEMO have advised that the minimum stable load that can be maintained is 600 MW. At this level of load, all generation must be synchronous thermal generation to maintain system stability. Above this level of load, a minimum of 600 MW of synchronous thermal generation must be scheduled to maintain system stability.

To implement this requirement, we will add a constraint that a minimum of 600 MW of thermal generation must be maintained at all times. Should demand fall below 600 MW, a violation penalty price will be incurred, which will set the resulting market price. The presence of this penalty in the market price results will indicate an unstable level of system demand.

A limited set of facilities are allowed to contribute to the minimum generation limit. With the planned retirement of the coal generators, the total capacity of the remaining generators in this set will become insufficient to supply the 600MW required. When this happens, we expand the list of contributing generators to all include all gas generators.

[10]https://www.cleanenergyregulator.gov.au/NGER/National%20greenhouse%20and%20energy%20reporting%20data/electricity-sector-emissions-and-generation-data/electricity-sector-emissions-and-generation-data-2020-21.

2.2.10 Other Operational Constraints and Offer Patterns

The WEMSIM model assumes by default that generators offer their capacity at their Short Run Marginal Cost (SRMC). To replicate actual generation patterns, additional operations constraints are placed on some plant.

AEMO-supplied constraints

Specific facility constraints have been implemented based on advice provided by AEMO.

Coal supply situation

AEMO have supplied information that a current coal supply disruptions are affecting the operation of the coal generators. This has been reflected in a set of constraints on the operations of the coal generators.

This coal supply situation is assumed to affect each of the scenarios as follows:

Table 7. Coal supply situation by scenario

Scenario	Assumption
High	Coal supply situation lasts until end of June 2023
Base	Coal supply situation lasts until end of March 2023
Low	No shortage of coal supply

Benchmarking against SCADA data

To further enhance the accuracy of the model, we performed benchmarking against SCADA data. Dispatch of the major plants was compared to recent SCADA data of actual dispatch. From this analysis, additional constraints on plants were implemented where the SCADA data showed consistent generation patterns (such as minimum generation levels). These changes were further confirmed by analysis of actual offer data submitted to AEMO.

The main impact of this benchmarking was an increase in generation from certain gas-fired facilities above what would be predicted by SRMC-based dispatch alone.

2.3 Transmission Network and Constraints

It is expected that on 1 October 2023, 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 2023 to 2032. Hence, we assume that NEM style SCED will apply (namely a single zone hub and spoke market with the reference node at Southern Terminal). A set of SCED constraint equations has been supplied by AEMO and has been implemented in the model.

2.4 Demand

Our demand forecasting methodology has been taken from the 2022 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 distributed generation. It involves creating underlying demand forecasts[11], and subtracting forecasted distributed 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.

This year we are basing the load on three historical load years (Capacity Years 2018/29, 2019/20, and 2020/21), with associated distributed PV profiles, to create three sets of demand forecasts, reflecting different climactic conditions. Each of the High, Base and Low scenarios will be run for each of the three demand forecasts to create three sets of results for each scenario.

This approach has five steps:

- Create the underlying load profile: The underlying load shape is developed using historical sent out generation data for each of the three historical years to create the underlying reference load profile.
- Scale the underlying load profile to forecasted values: Hourly underlying load forecasts for each year in the modelling horizon are developed by scaling up each underlying reference load profile to match the underlying 50% POE peak and expected energy forecasts for the respective Capacity Year.

---

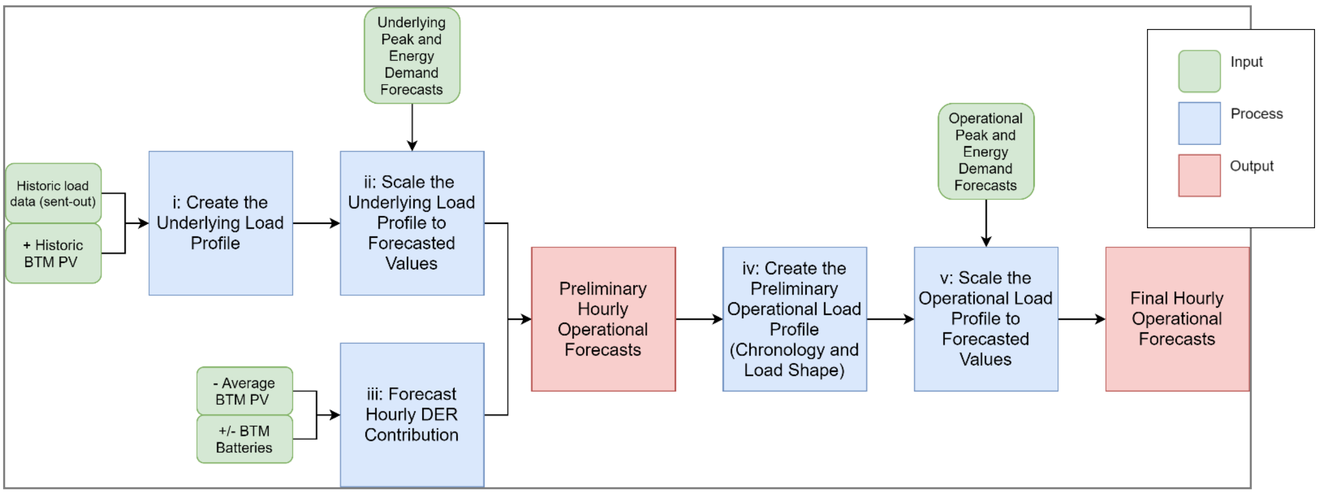
[11] Based on historical data and AEMO's underlying peak/energy demand forecasts.

- Forecast hourly distributed energy resources (DER) contribution[12]: Using historical DER data provided by AEMO, we forecast hourly distributed PV generation (using actual data for the corresponding underlying reference load year), and forecast battery charge/discharge, for each Capacity Year.
- 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.
- 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.

Figure 5: Overview of load forecasting process



Demand forecasts from the 2022 WEM ESOO have been provided by AEMO and are summarised for each of our GPG scenarios[13] in Tables 8 - 10. We have used the 10% - high demand growth/ 50% - expected demand growth/ 90% - low demand growth POE forecasts

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

[13] See Section 2.8 for further details about our scenario definitions.

(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.

Capacity year/calendar year conversion

The above process produces hourly demand forecasts by capacity year, whereas the GPG modelling is performed by calendar year. To obtain demand forecasts by calendar year, the hourly forecasts by capacity year are concatenated to obtain a continuous hourly forecast over the forecast years. This is then divided into individual capacity years for GPG modelling purposes.

The provided forecasts cover up to the end of the 2031/32 capacity year. This is extended for a further year at the same growth rate as 2030/31-2031/32, so that forecasts for the final 3 months of 2032 can be obtained.

Table 8: Demand forecasts - Base scenario

	Underlying Forecasts		Operational Sent-out Forecasts	
Capacity Year	50% POE peak forecast - Expected (MW)	Annual Consumption – Expected (MWh)	50% POE peak forecast - Expected (MW)	Annual Consumption – Expected (MWh)
2022-23	4,277	18,551,470	3,781	16,545,290
2023-24	4,308	18,668,880	3,790	16,205,860
2024-25	4,345	18,745,950	3,821	15,892,830
2025-26	4,382	18,962,230	3,855	15,758,820
2026-27	4,445	19,300,690	3,899	15,762,650
2027-28	4,476	19,560,250	3,934	15,681,750
2028-29	4,520	19,818,510	3,967	15,615,460
2029-30	4,550	20,174,410	4,018	15,680,140
2030-31	4,619	20,640,360	4,075	15,871,200
2031-32	4,646	21,206,840	4,141	16,151,240

Table 9: Demand forecasts - High scenario

	Underlying Forecasts		Operational Sent-out Forecasts	
Capacity Year	10% POE peak forecast - High (MW)	Annual Consumption – High (MWh)	10% POE peak forecast - High (MW)	Annual Consumption – High (MWh)
2022-23	4,584	19,789,710	4,121	17,601,350
2023-24	4,665	20,127,380	4,182	17,175,120
2024-25	4,777	20,467,160	4,278	16,836,260
2025-26	4,880	20,951,860	4,389	16,722,340
2026-27	4,975	21,536,310	4,500	16,799,170
2027-28	5,080	22,193,710	4,594	17,043,610
2028-29	5,184	22,787,270	4,697	17,300,780
2029-30	5,244	23,468,910	4,798	17,729,370
2030-31	5,378	24,226,510	4,885	18,276,050
2031-32	5,448	25,037,930	4,978	18,879,790

Table 10: Demand forecasts - Low scenario

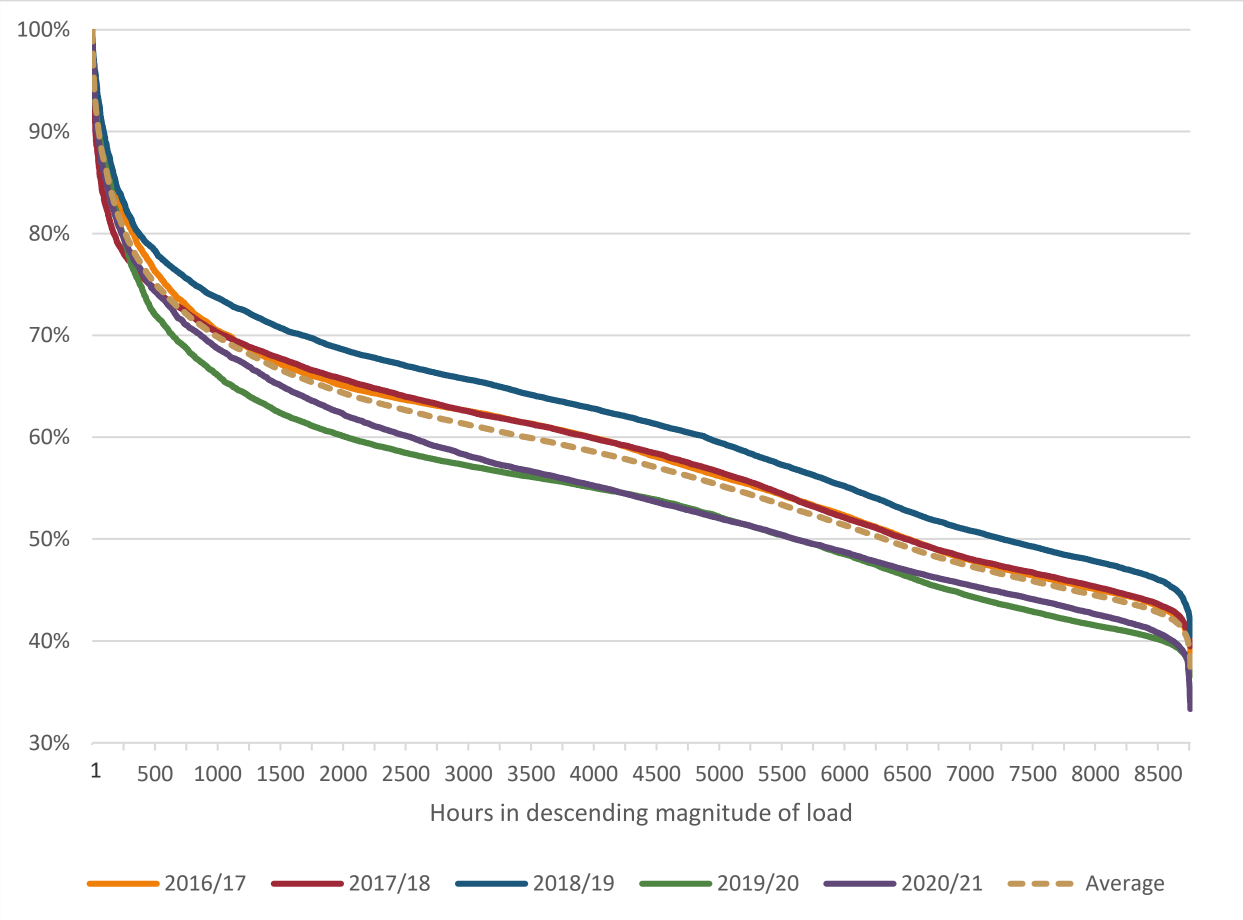
	Underlying Forecasts		Operational Sent-out Forecasts	
Capacity Year	90% POE peak forecast - Low (MW)	Annual Consumption – Low (MWh)	90% POE peak forecast - Low (MW)	Annual Demand – Low (MWh)
2022-23	4,067	17,083,790	3,512	14,986,180
2023-24	3,965	17,061,110	3,399	14,562,380
2024-25	3,969	16,877,090	3,388	14,047,950
2025-26	3,931	16,808,410	3,352	13,663,240
2026-27	3,910	17,058,690	3,323	13,617,980
2027-28	3,951	17,188,340	3,363	13,448,850
2028-29	3,956	17,295,560	3,366	13,287,630
2029-30	3,973	17,439,150	3,383	13,211,130
2030-31	4,013	17,595,600	3,407	13,180,130
2031-32	4,006	17,748,510	3,423	13,168,840

2.4.1 Creating the Underlying Load Profile

We first develop a 'reference' underlying load profile by constructing underlying historical load duration curves (LDCs)[14] for the last three full Capacity Years (2018/19-2020/21). As the historical total sent-out generation from AEMO reflects operational demand and includes the effects of distributed PV generation, we add historical distributed PV generation[15] (provided by AEMO) to the historical load data before conducting the above analysis.

For our modelling, we will use the 2018/19, 2019/20 and 2020/21 load profiles. Each of the 3 scenarios will be simulated for each of these 3 load shapes. Figure 6 below shows the reference load shapes:

Figure 6: Underlying reference load shape



[14] A load curve ordered in descending order

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

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 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[16] 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. Thus, we have defined F(h) as follows:

---

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

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

Where:

- p denotes the ratio of the underlying peak forecast to the reference underlying peak demand
- e denotes the ratio of the underlying expected demand forecast to the reference 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.

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:

- Distributed PV generation
- Distributed 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.

Distributed PV Generation

Distributed PV generation is based on historical distributed PV generation data provided by AEMO, scaled using capacity forecasts provided by AEMO.

Distributed Battery Storage

Distributed battery storage includes 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:

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

Where:

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

Residential, small commercial, and large commercial capacity forecasts have been provided by AEMO for each of the 3 scenarios.

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 such that:

$$OL_d = DL_d \times LF$$

Where OL_d refers to the operational load at datetime d and LF is the loss factor for a given Capacity Year. We have taken the average of all the transmission loss factor values calculated by Western Power[17] which comes down to 1.0379 and have assumed the loss factor to be the same for the future years as shown in Table 11:

Table 11: Loss factors applied

CY	Loss Factor
2022-23	1.0379
2023-24	1.0379
2024-25	1.0379
2025-26	1.0379
2026-27	1.0379
2027-28	1.0379
2028-29	1.0379
2029-30	1.0379
2030-31	1.0379
2031-32	1.0379
2032-33	1.0379

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).

[17] From https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/loss-factors

- Indexing the load shape by its associated date in the hourly forecasts to create a load chronology.

This gives 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 DPV generation, the likelihood of one of our DPV 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 gives us hourly load forecasts that capture year-on-year variation in load shape and chronology, while maintaining alignment with the forecasts provided by AEMO.

2.5 Fuels

The 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 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 2021 Major Commodities Resources Data, published by the Government of Western Australia Department of Mines, Industry Regulation and Safety[18]. This provides data on the quantity and value of coal produced in WA. Assuming a calorific value of 19.7 GJ/t[19], this yields the following historical prices (Figure 7):

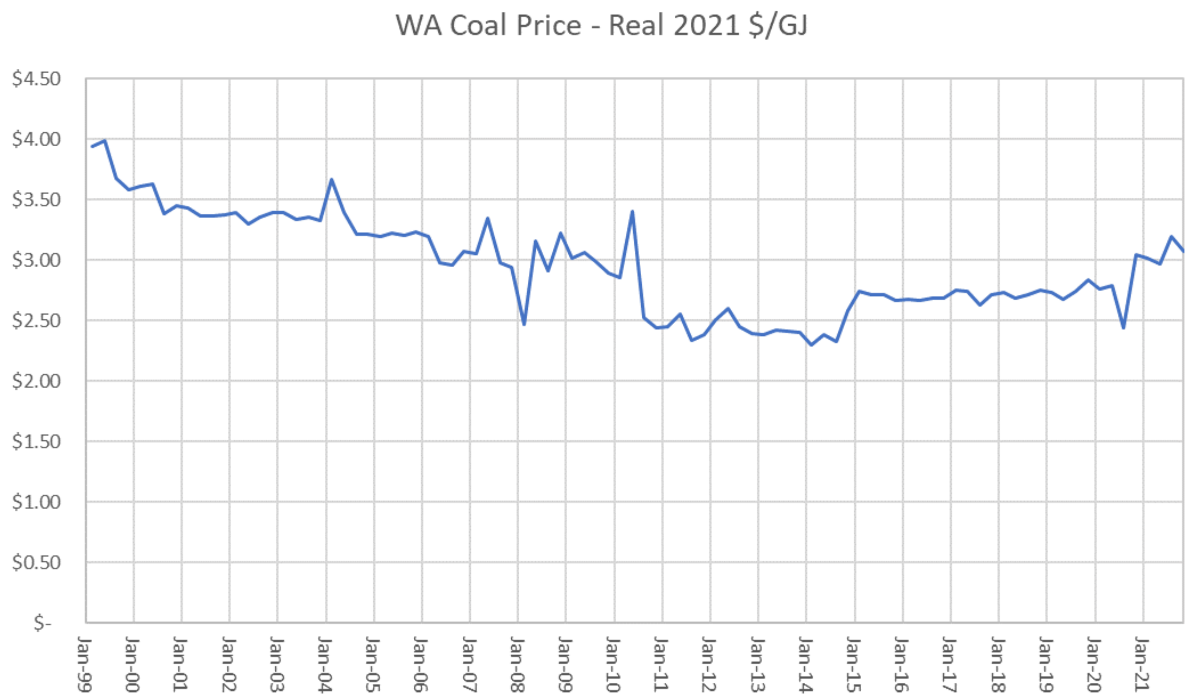


Figure 7. Historical WA Coal Prices

This data shows a 5-year period of stable prices followed by a pandemic-related disruption. We propose to use a constant price (in real 2021 AUD terms) of the average price over the last 5 years. This results in a constant price of AUD 2.80/GJ.

2.5.3 Distillate

Historical "Perth Terminal Gate" prices for distillate (i.e., Diesel) are available from the Australian Institute of Petroleum[20]. 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, the crude oil forecast that underlies the gas price forecasts (as referenced in section 2.5.1), a distillate price forecast can be obtained as provided in Table 12.

---

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

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

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

Table 12. Distillate price forecast

Year	Base (Real 2021 AUD/GJ)	Low (Real 2021 AUD/GJ)	High (Real 2021 AUD/GJ)
2023	14.63	12.94	17.11
2024	14.63	12.54	17.11
2025	14.63	12.54	17.11
2026	14.63	12.74	17.11
2027	14.63	12.94	17.11
2028	14.63	12.94	17.11
2029	14.63	12.94	17.11
2030	14.63	12.94	17.11
2031	14.63	12.94	17.11
2032	14.63	12.94	17.11

The following parameters are also assumed in this forecast:

- Excise tax (currently 0.433 c/l) and GST (10%) are rebated
- Calorific value is 38.6 MJ/l[21]
- Transport cost to Parkeston area is 1.1 c/l[22] (Australian cents)

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

[22] AEMO 2020-21 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 will model four Ancillary Services[23], as set out in Table 13 below:

Table 13: Modelled Ancillary Services and Requirements

Ancillary Service	Requirement[24]
Spinning Reserve (SR)	Maximum of: • 70% of the largest generating unit • 70% of the largest contingency event that would result in generation loss • Maximum load ramp expected over 15 minutes
Load Rejection Reserve (LRR)	97 MW
Load Following Ancillary Service Up (LFAS Up)	110 MW (5:30 AM – 8:30 PM) 65 MW (8:30 PM – 5: 30 AM)
Load Following Ancillary Service Down (LFAS Down)	110 MW (5:30 AM – 8:30 PM) 65 MW (8:30 PM – 5: 30 AM)

We note that there is currently reform work under way defining new ancillary services 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 will assume that the above quantities will remain in force. However, it is reasonable to assume that the market for SR will be opened up post-reform, so that a larger number of facilities will be able to provide this service. We will not assume the same for LFAS, as there are entry barriers to providing LFAS.

[23] To be called Essential System Services as part of the WEM transition to SCED commencing Oct 1, 2023. Refer to https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2022/2022-aemo-reliability-assessment---rbp.pdf?la=en

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

2.7 Energy Storage

2.7.1 Distributed Energy Storage

Distributed energy storage is modelled as a fixed charge and discharge profile, as specified in section 2.4.3.

2.7.2 Grid-Connected Storage

New build of grid-connected storage is specified in section 2.2.4.

2.8 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 14:

Table 14. Scenario definitions

Scenario	High	Base	Low
Operational consumption	High	Expected	Low
Peak demand	High case - 10% probability of exceedance (POE)	Expected case - 50% POE	Low case - 90% POE
Gas price	Low	Expected	High
Distributed PV and battery storage	Low	Expected	High
Generation retirements (in addition to common set of retirements specified in Table 1)	Bluewaters retires 1 July 2023	Bluewaters retires 1 Oct 2029	Bluewaters does not retire
Generation new build	Standard new build plus additional new build	Standard new build	Standard new build
Coal supply situation	Coal supply situation lasts until end of June 2023	Coal supply situation lasts until end of March 2023	No shortage of coal supply

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.

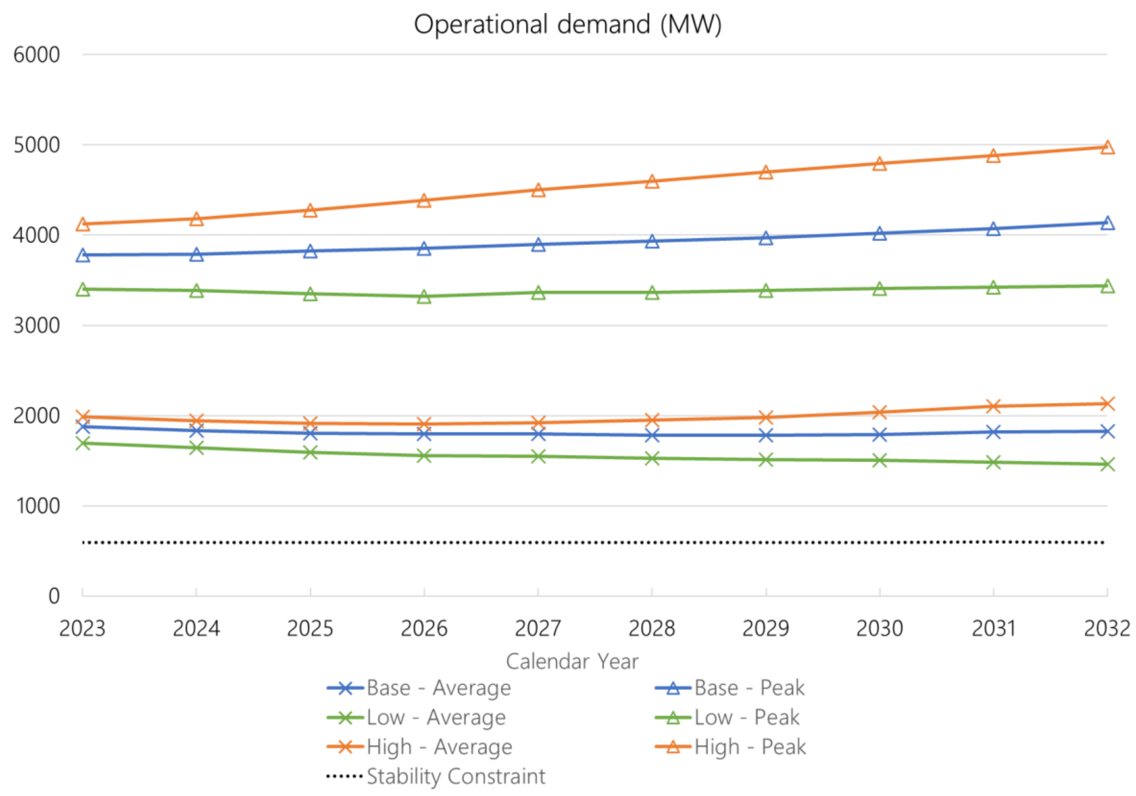
In the following sections, we provide summaries of the following results on an annual basis:

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

3.1 Operational Demand

Figure 8 shows the hourly average and peak demand for each Capacity year in the modelling horizon[25].

Figure 8: Minimum and average operational demand



[25] For simplicity, the values shown are just for the forecasts based on the 2020/21 base year.

Relative to the 2021 GPG modelling demand assumptions, the following differences are significant:

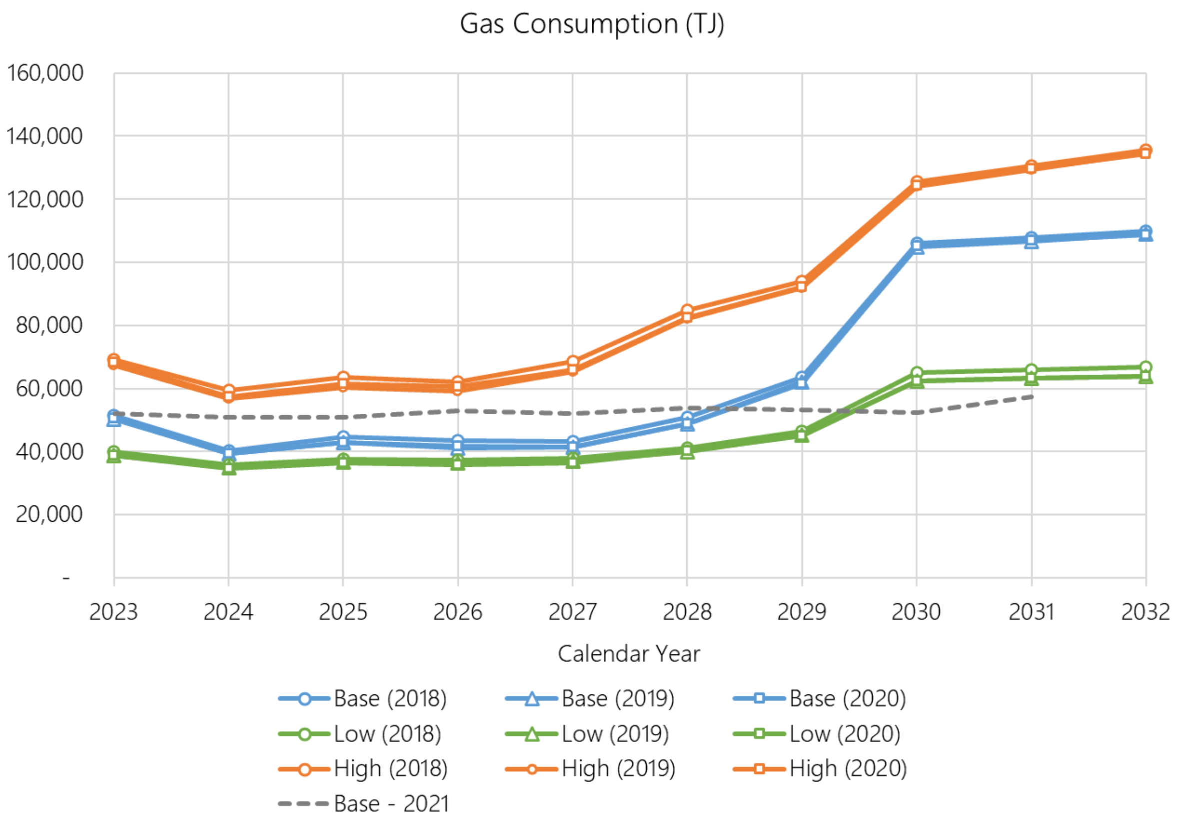
- Average demand is similar
- Peak demand is higher

3.2 Gas Consumption

Figure 9 shows the annual total gas consumption from GPG from the model results (on a calendar year basis). Base gas consumption from the 2021 GPG forecasts is included for comparison.

Results are shown for each of the base, high and low scenarios (see section 2.8) and each of the 3 base load profiles (see section 2.4).

Figure 9: Gas consumption



Compared to the 2021 GPG modelling results, Base scenario gas demand is lower for the first 6 years of the outlook horizon. This is the result of a combination of factors:

- Increased DER forecasts

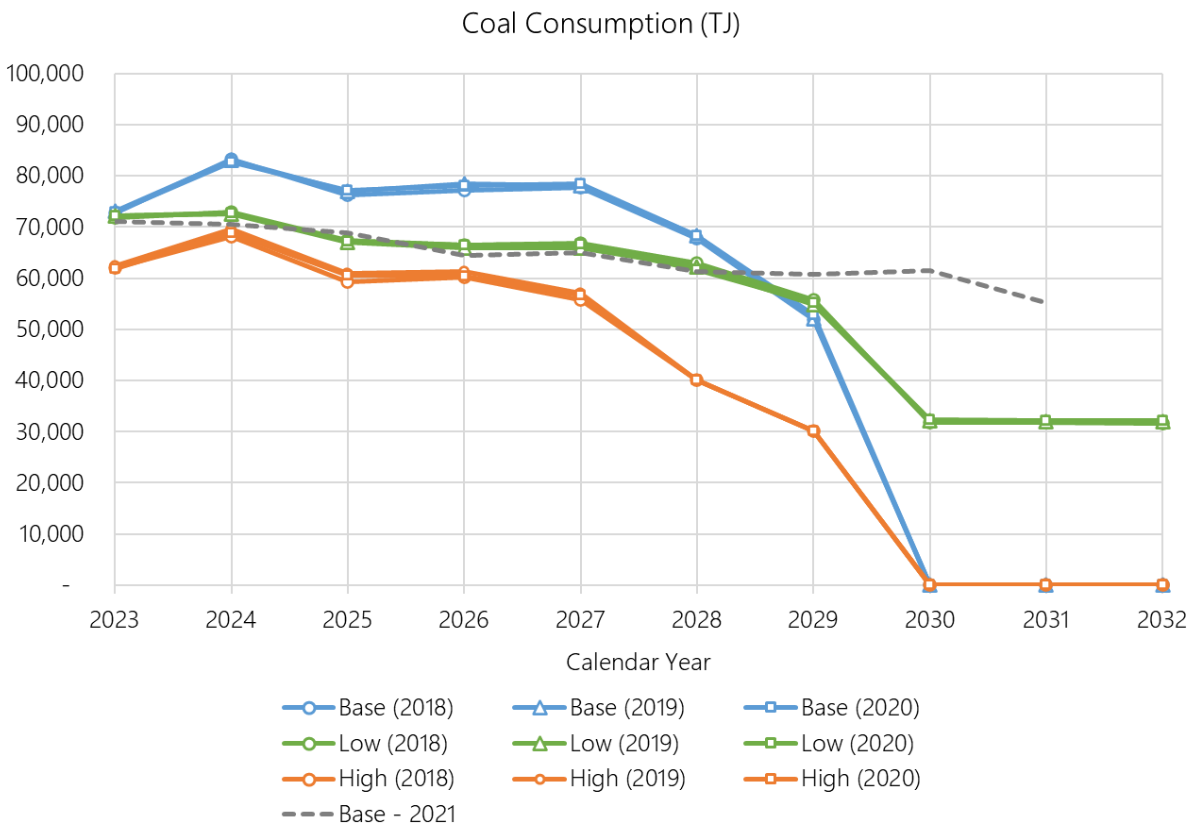
- Lower mid-day demand
- Refinement of generator offer assumptions

For the final 5 years of the outlook horizon, Base scenario gas demand is significantly higher. This is mainly due to the additional retirements of the coal plants, relative to the 2021 forecast.

3.3 Coal Consumption

Figure 10 shows the annual total coal consumption for electricity generation from the model results.

Figure 10: Coal consumption



Compared to the 2021 GPG modelling results, Base scenario coal demand is higher for the first 6 years of the modelling horizon, driven by lower gas generation. Following that, coal use drops dramatically, following the retirements of the coal units.

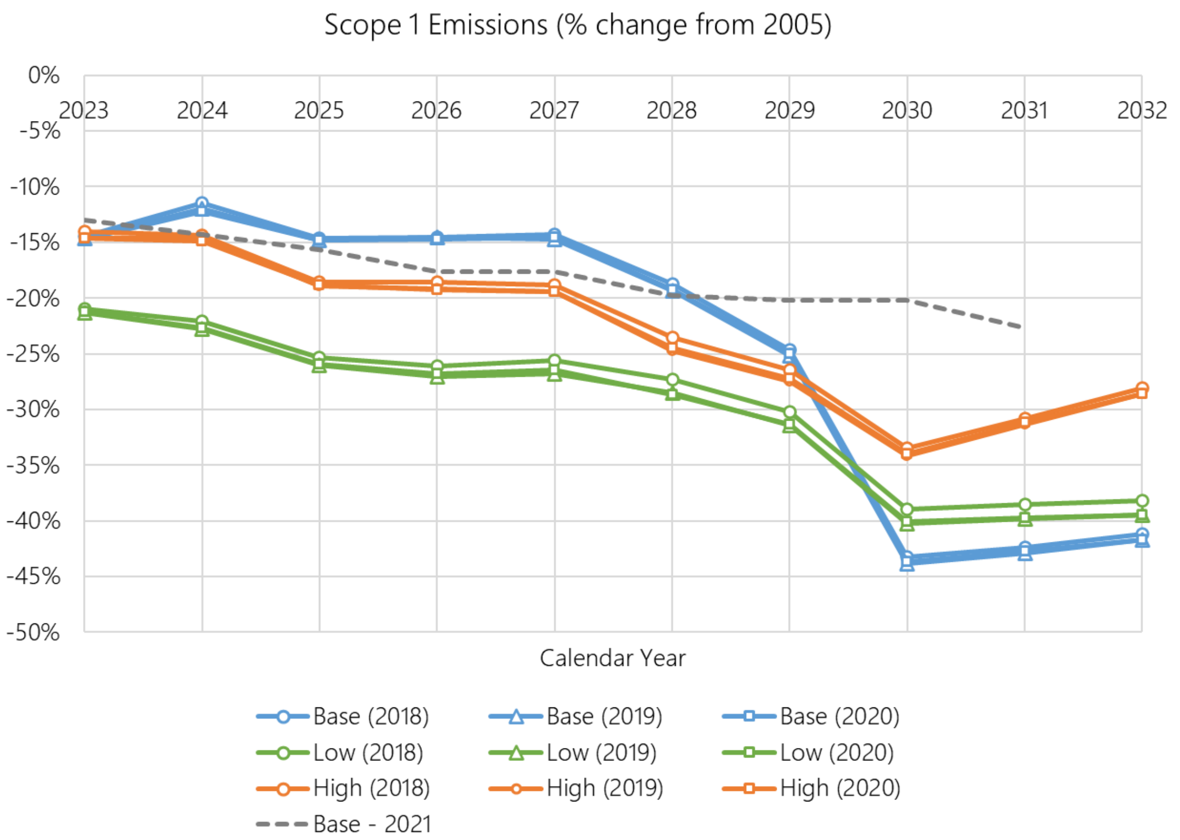
The scenario results are not in a Low-Base-High order, and cross over each other for the following reasons:

- The High scenario has significant levels of non-coal new build that are not in the other scenarios (see section 2.2.5). This new capacity competes with coal generation, resulting in lower coal consumption.
- The Low scenario does not have the current coal supply constraints applied (see section 2.2.10), so does not experience the dip in coal generation in 2023 that is seen in the Base and High scenarios
- By 2030, both the High and Base scenarios have no remaining coal generation capacity due to retirement assumptions (see section 2.2.3). Therefore, coal consumption drops to zero in these scenarios. In the Low scenario, there is still coal consumption as the Bluewaters units do not retire.

3.4 Emissions

Figure 11 shows total annual Scope 1 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).

Figure 11: Emissions



Relative to the 2021 GPG modelling results, Base scenario emissions are initially increased, due to the higher coal generation. With the retirement of the coal plant, emissions reduce significantly to be much lower than the 2021 forecasts.

Similarly to the coal consumption results, the scenario results are not in a Low-Base-High order, and cross over each other for the following reasons:

- The High scenario has significant levels of renewables new build that are not in the other scenarios (see section 2.2.5). This new renewable capacity reduced emission to below the base case emissions.
- The retirement of the Bluewaters units at the end of 2029 in the Base scenario reduces emissions from 2030 onwards to below the Low scenario, which still has these units operating. In the high scenario, this retirement occurs earlier resulting in lower emissions, but this is offset by the emissions from higher gas consumption.

4 Conclusions

4.1 Key Insights

The following key insights can be drawn from this analysis:

- The most significant factor affecting results relative to the 2021 forecasts is the retirements of the coal plants. This has the effect of:
  - Increasing gas consumption
  - Decreasing coal use
  - Reducing emissions
- Higher DER generation assumptions and lower mid-day demand have resulted in a lower base scenario gas use forecasts than the previous year's modelling before the impact of the coal retirements outweighs this effect.
- The Low scenario is the only scenario that meets the Australian Government's newly decreased emissions reduction target of 43% by 2030. This is driven by lower demand levels, which impact coal generation. The base scenario achieves 39-40% reductions. All scenarios have significantly lower emissions by 2030, due to coal plant retirements.

4.2 Limitations and Gaps

It is acknowledged that the following limitations in the modelling techniques are present. These are necessary to provide valid results within a reasonable time and budget:

- The model used is a 'perfect competition' model - market power modelling has not been applied. We would expect that the main impact of market power would be that market prices may be higher in general, especially in periods of high demand and prices. In periods of low demand, there is very little market power, so we would not expect the insights to be affected. We would not expect physical results (e.g. fuel demand and emissions) to be significantly affected.
- Integer unit commitment decisions are only applied to select generators to ensure reasonable run-times (all coal units, ALINTA_PNJ_U1/2, COCKBURN_CCG1 and

NEWGEN_KWINANA_CCG1[26]). The impact of this is that some generators may cycle (i.e. start up and shut down) more often than in reality, and some may occasionally be dispatched below their minimum stable operating level. The expected impact of this will be the allocation of dispatch between individual units on an hour-by-hour basis, but we do not expect significant impacts on a system-wide level, so this will not affect the insights and results presented above.

- The model is an hourly dispatch model, rather than half-hourly. Analysis by RBP confirms that this is not significant for this purpose.
- Minimum demand forecasts produced by AEMO for the 2022 WEM ESOO have not been reflected in our load forecasting methodology. The impact of this is lessened due to the modelling of the operational stability constraint.

Furthermore, the validity of modelling results is dependent on the accuracy of modelling input assumptions. This model is dependent on data supplied by AEMO and third parties as specified in Section 2 of this document.

[26] These units were chosen from a comparison of historical and modelled dispatch as the units that most required integer unit commitment to achieve accurate unit dispatch modelling.

GLOSSARY

Table 15 presents a glossary of the terms used in this report:

Table 15: Glossary

Term	Definition
BESS	Battery Energy Storage System
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
Distributed energy resource (DER)	DER technologies refers to small-scale embedded technologies that either produce electricity, store electricity, or manage consumption, and reside within the distribution system, including resources that sit behind the customer meter. Any generators that are connected to the distribution network that are assigned Capacity Credits are not included in the definition of DER technologies, for example Northam solar farm.
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.

Term	Definition
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.
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 DER 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 DER PV generation and the impacts of battery storage. Due to the small uptake of battery storage to date, for historical values the impact of DER battery is assumed to be negligible.