ROBINSON BOWMAKER PAUL

AUSTRALIAN ENERGY MARKET OPERATOR

GAS POWERED GENERATION FORECAST MODELLING 2023 - 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 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, and Low gas demand, over a 10-calendar year horizon (2024 - 2033).

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 2022 GPG modelling. Key changes having a significant effect on the results include:

- Utilized operational demand profiles used in the 2023 WEM ESOO reliability forecast[2]
- Updated Essential System Services Formulation
- Updated fuel price assumptions
- Benchmarking coal generation against historical coal generation levels.
- Coal facility retirements in line with WA government announcements
- Additional generic capacity is built to meet the Reserve Capacity Target
- Improved modelling of intermittency in renewable resources' profiles to better capture periods of renewable energy deficiency.

The methodology employed is largely consistent with previous years.

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

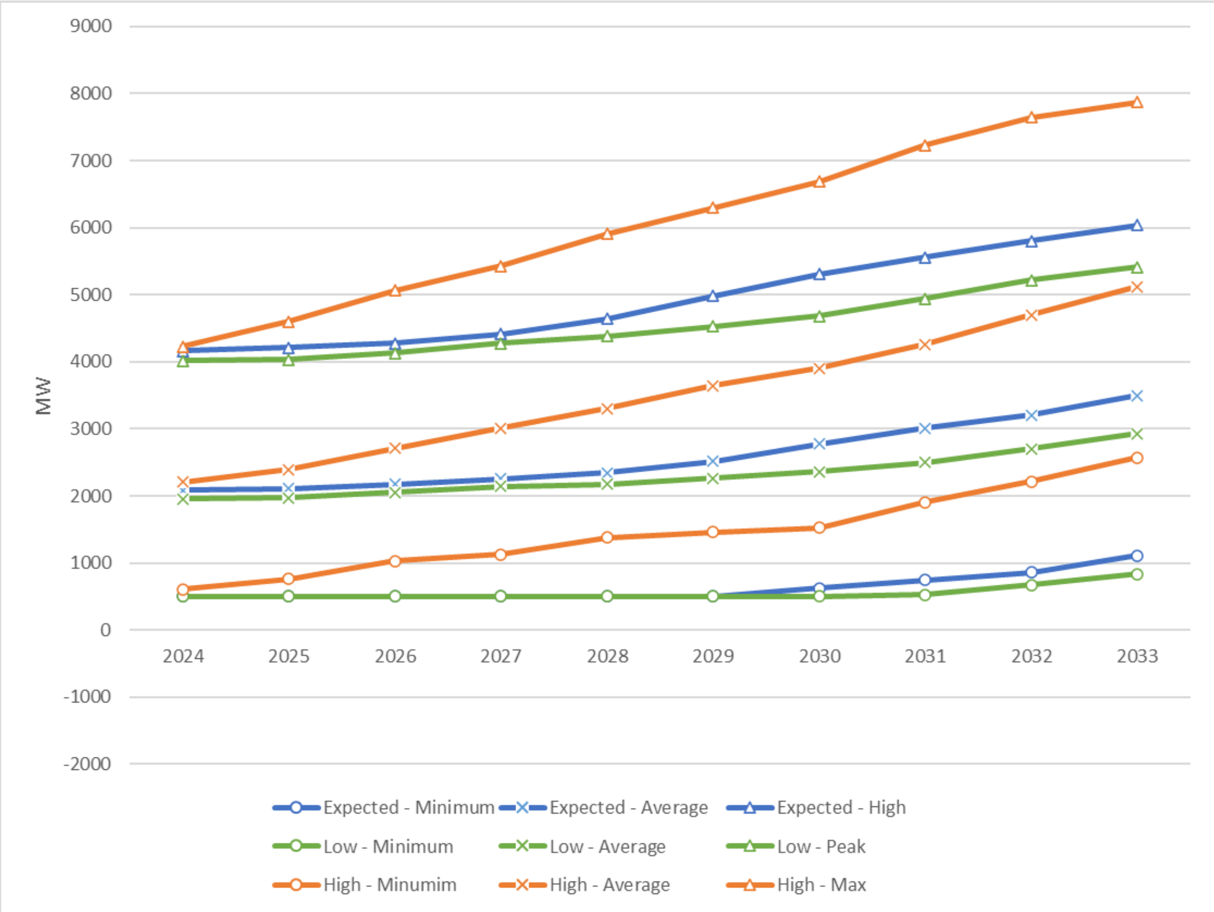
[2] See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo

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 2022 GPG modelling demand assumptions, the 2023 demand profile has much higher peak, average and minimum demand. In particular, minimum demand is now consistently above zero throughout the modelling horizon due to changed DER development assumptions. This eliminates the requirement for grid-scale batteries to absorb negative operational demand, however batteries will still be utilised for system stability in Low demand periods.

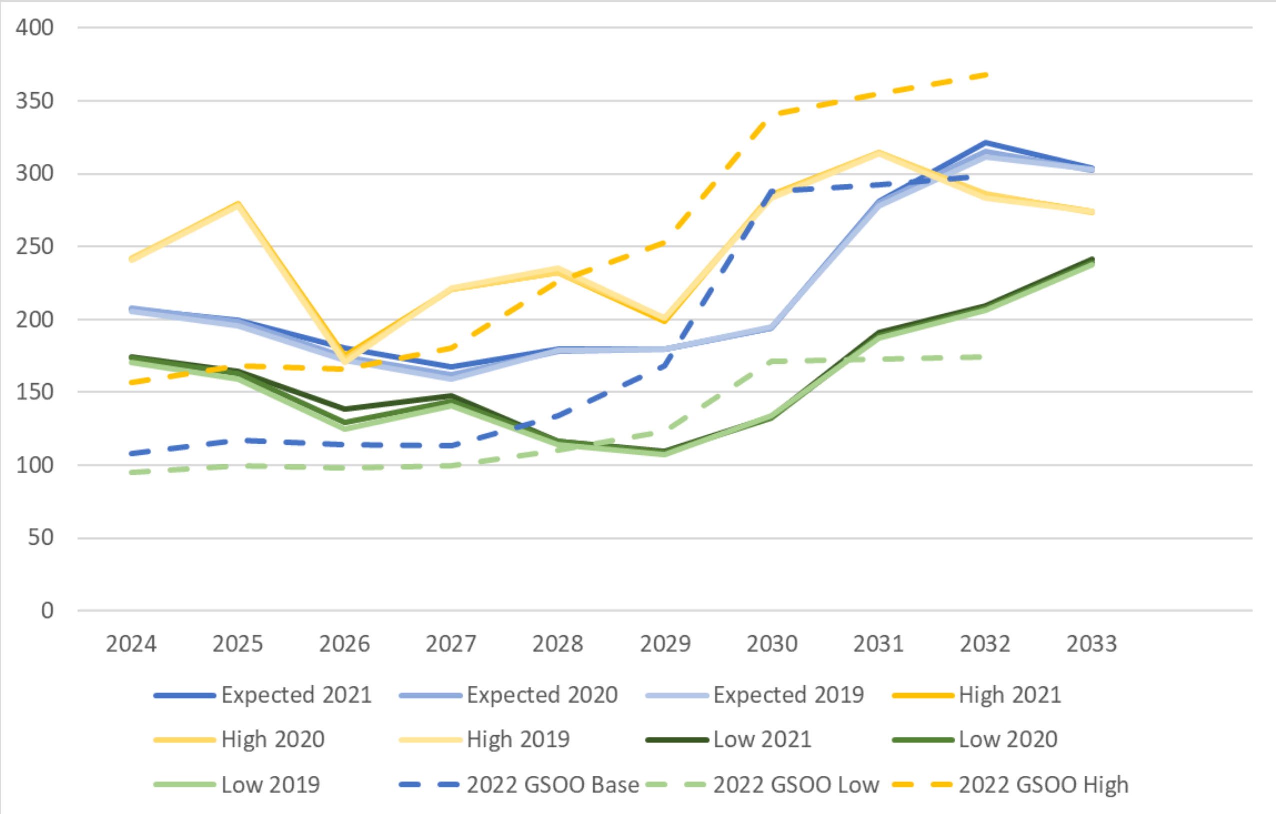
Three reference years were used for analysis: 2019, 2020, 2021. These years are scaled to meet the projected peak, minimum and annual demand for each forecasting year.

Gas Consumption

Figure 2 shows the annual total gas consumption from GPG from the model results (on a calendar year basis). Gas consumption from the 2022 GPG forecasts is included for comparison.

Results are shown for each of the Expected, High and Low scenarios.

Figure 2: Gas consumption (TJ/day)



Compared to the 2022 GPG modelling results, gas demand is higher for the first 5 years of the modelling horizon. This is the result of a combination of factors:

- Coal offtake limits require greater gas consumption
- Greater variability in intermittent profiles requires gas to bridge gaps
- Higher demand growth

From 2029 onwards gas demand increases in all scenarios, as it did in the 2022 GPG results. However, the increase occurs one year later due as the retirement of Bluewaters being pushed back one year.

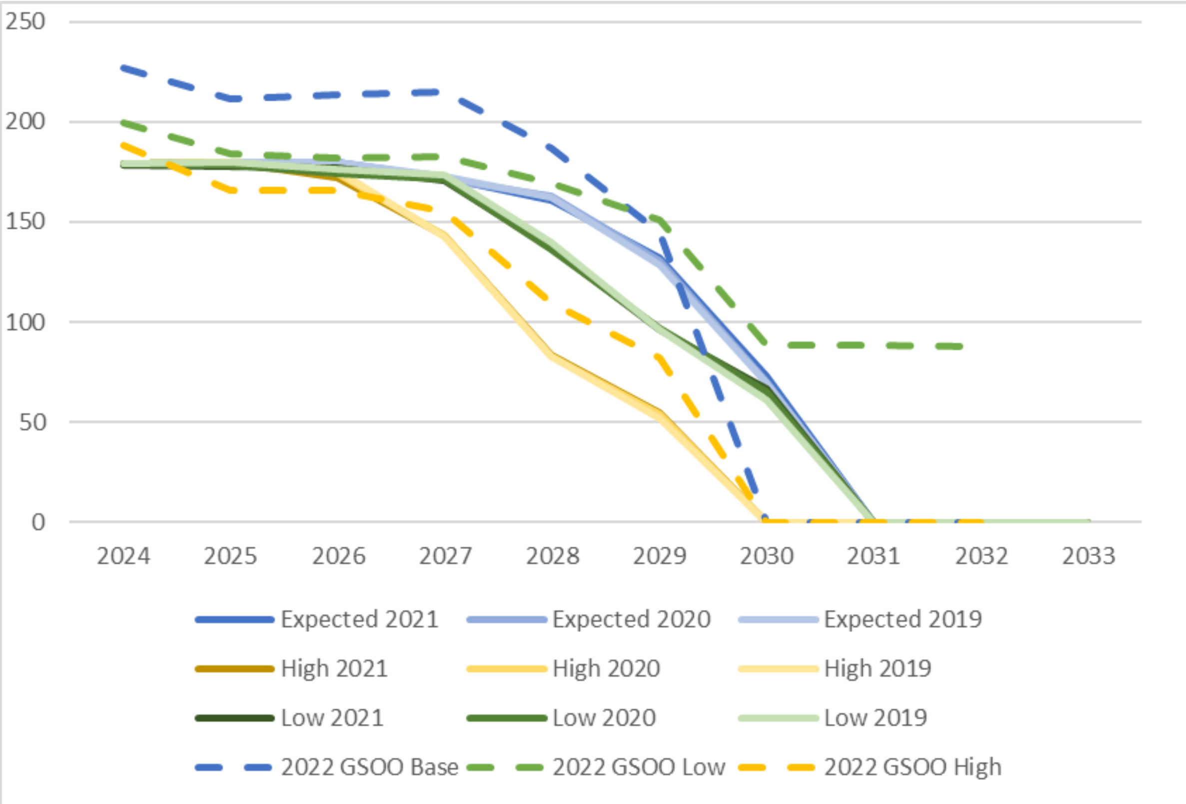
In the Low scenario, gas consumption increases after 2031 due to the complete retirement of all coal capacity, whereas the 2022 GPG results retained some coal capacity in the Low scenario.

The High scenario exhibits greater year-to-year volatility in gas consumption and drops below the expected scenario in the final two years due to the higher level of renewables new build (see the following section on emissions results).

Coal Consumption

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

Figure 3: Coal consumption (TJ/day)



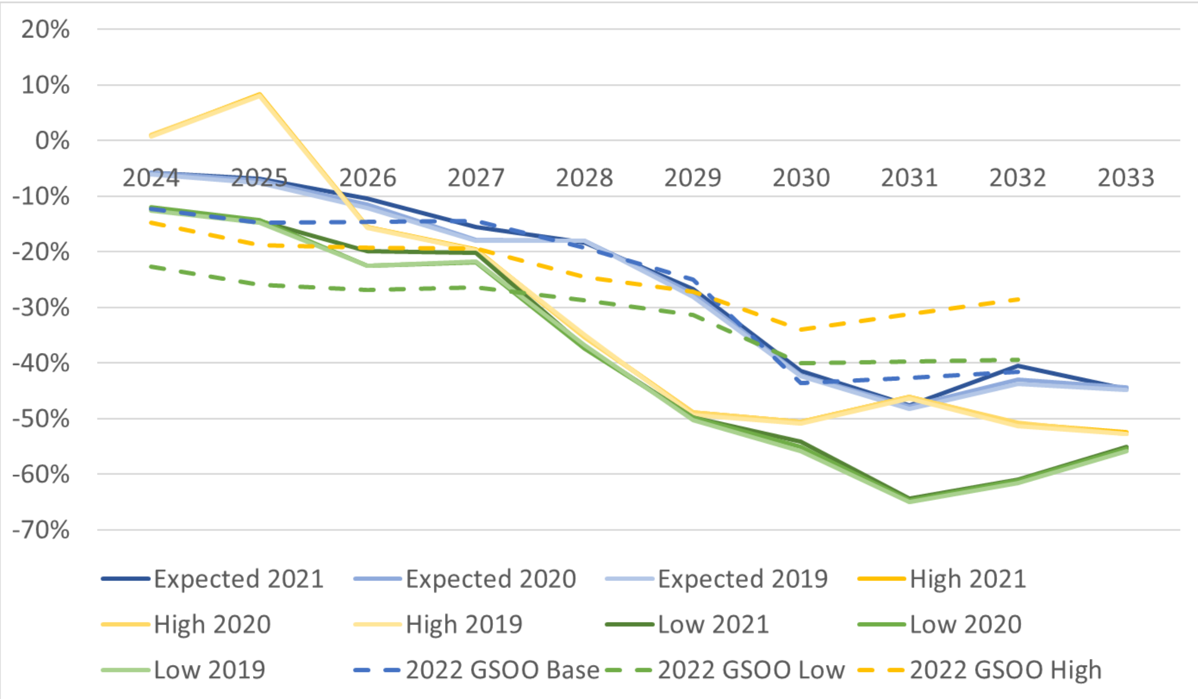
Compared to the 2022 GPG modelling results, Expected and Low scenarios' coal usage is lower for the first 6 years of the modelling horizon. This is due to a limit placed on the availability of coal. Different retirement schedules, and an increase in renewable generation also influence the 2023 results, dropping consumption below that of the 2022 modelling.

The main difference between coal consumption in this year's scenarios comes from differences in retirement schedules. By 2031 coal facilities have retired in all scenarios.

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 (% change from 2005)



Relative to the 2022 GPG modelling results, Expected Scenario emissions are very similar with the exception of the first 2 years. This small difference primarily stems from constraints on building new generic facilities during the first two years of the modelling horizon. The constraint is attributed to necessary development time for these facilities, leading to increased gas usage to meet demand. A similar pattern is also observed for the Low scenario. This limitation on new generation also explains the very high emissions in the first two years of the High scenario, where large increases in demand cannot be met by renewable intermittent generation.

The High scenario has lower emissions than the Expected scenario for the following reasons:

- The High scenario's annual consumption to peak demand ratio was higher than other scenarios. This meant that generic new build batteries were less useful as there was insufficient energy to charge them leading up to system stress events. For this reason, more wind, solar and gas were built to ensure sufficient resources in peak events. The comparative increase in renewable generation, and displacement of coal with gas dropped overall emissions.
- Bluewaters retires in 2026 instead of 2030.

Overall, when compared to the 2022 analysis, the 2023 analysis shows greater volatility in emission reduction between scenarios due to greater differences in the generic new build installed in each scenario. Similarly, the overall emissions profile is lower, reflecting a significant amount of new renewable generation installed over the 10-year period.

Key Insights

The most significant factor affecting results relative to the 2022 forecasts are:

- Coal supply availability is now limited to match the offtake in historic years. This increases gas consumption in earlier years
- Higher demand forecasts increasing the requirement for generic intermittent capacity in the model

In the short-term gas generation is likely to drop slightly or plateau as known new capacity enters the market

In the long term, the retirement of coal increases the demand for gas generation which is required to meet peak demand and support renewables in long, dark, and still weather conditions.

Contents

1 INTRODUCTION

1.1 PROJECT BACKGROUND

The Gas Services Information (GSI) Regulations[3] 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 (2024 – 2033).

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
- Expected
- High

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

- Gas and distillate prices
- Annual, peak, and minimum demand
- Specific and generic new build

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

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

2 Modelling Methodology and Assumptions

We use our 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 or WEM)
- 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.

2.1 Facilities

In this section we set out our assumptions around the technical parameters and operational costs of:

- Existing generation and energy storage facilities
- Specific generators that are forecast to come online during the 10-year modelling horizon
- Generic generators added to the model to meet the Reserve Capacity Target
- Retirements
- The intermittent generation profiles of utility-scale generation (wind/solar farms and biogas)

2.1.1 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, 2021 and 2022 GPG modelling assignments.

The quantity of carbon emissions resulting from electricity generation will be calculated in WEMSIM, based on emission factors published by the Clean Energy Regulator for existing and new generators in the SWIS[6].

2.1.2 Retirements

On 15 June 2022, 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-Apr-25
COLLIE_G1	1-Oct-27
MUJA_G7	1-Oct-29
MUJA_G8	1-Oct-29

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

6https://www.cleanenergyregulator.gov.au/NGER/National%20greenhouse%20and%20energy%20reporting%20data/electricity-sector-emissions-and-generation-data/electricity-sector-emissions-and-generation-data-2021%E2%80%9322

Table 2: Additional retirements – Expected and Low Scenarios

Unit	Retirement Date
BW1_BLUEWATERS_G2	1-Oct-30
BW2_BLUEWATERS_G1	1-Oct-30

Table 3: Additional retirements – High Scenario

Unit	Retirement Date
BW1_BLUEWATERS_G2	1-Oct-26
BW2_BLUEWATERS_G1	1-Oct-26

2.1.3 Specific New Build

There are some new generators coming online during the 10-year modelling horizon. Additional new build, identified from AEMO's 2023 Expression of Interest (EOI) process, will be included in the High scenario only.

2.1.4 Capacity Upgrades

In addition, certain facilities receive capacity upgrades.

2.1.5 Generic new build

In some scenarios, the capacity of new facilities commissioned is insufficient to meet the Reserve Capacity Target (RCT) given high load growth and the retirement of many large thermal generators. In these scenarios, additional generic capacity is added to meet the RCT. Candidate facilities are evaluated based on several factors; quantitative and qualitative which include:

- Policy developments
- Economic and technical viability

The types of facility considered for new build include:

- CCGT
- OCGT (small)

- High Efficiency Gas Turbine (HEGT)
- Biomass
- Large scale solar PV
- Battery storage (2hrs storage)
- Battery storage (4hrs storage)
- Wind
- Solar Thermal

The economic viability of these facilities is assessed according to the capital costs and operating parameters published in the GenCost 2022-23 report published by CSIRO. CSIRO publishes three scenarios: Current policies, Global NZE post 2050 and Global NZE by 2050. Sensitivity analysis found that the choice of GenCost scenario did not affect the choice of new build significantly. For this reason, the most conservative scenario "Current Policies" was chosen to simplify the modelling process. The data is summarized in Table 4, and

Table 5. GenCost doesn't provide all necessary battery data, so some values have been taken from the AEMO's 2023 IASR assumptions workbook[7].

Table 4: Generic new build parameters (Real 2022-2023 AUD/kW)

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 (small)	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
HEGT	3	30	30	63.43	12	9.24	2
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

[7] https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx?la=en.

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

Table 5: Generic new build capital costs (Real 2022-2023 AUD/kW)

Technology Type	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
OCGT (small)	1593	1540	1490	1442	1397	1369	1356	1354	1351	1349
CCGT	1706	1699	1694	1690	1671	1654	1639	1636	1633	1630
HEGT	1960	1960	1960	1960	1960	1960	1960	1960	1960	1960
Biomass	8666	8496	8340	8189	7898	7671	7506	7519	7532	7545
Large scale solar PV	1516	1407	1301	1197	1141	1103	1091	1058	1038	1022
Battery storage (2hrs storage)	1354	1274	1204	1144	1112	1082	1050	1020	988	958
Battery storage (4hrs storage)	2196	2068	1952	1852	1796	1760	1704	1644	1588	1528
Wind	2644	2519	2398	2284	2152	2056	1996	1989	1983	1978
Solar Thermal	6478	6339	6202	6050	5911	5789	5669	5562	5465	5376

In addition to economic and technical parameters, several political developments underpin the decisions around new build:[8]

- The WA government is expected to implement a GHG emissions intensity limit of 0.55 tCO2/MWh. Neither the 'Small OCGT' or 'Large OCGT' technologies referenced in the CSIRO GenCost report are able to meet this threshold.
- The WA government is likely to implement yearly GHG emissions limit of 1,000 tCO2e per MW of nameplate capacity per annum. This places CCGT facilities at a high risk of exceeding the limit given they cannot determine their dispatch quantities.

[8] https://www.wa.gov.au/system/files/2023-11/mac_23_november_2023_meeting_papers.pdf

The following new build profiles were generated using an iterative approach where the model was iterated many times with varying mixes of generation type added to meet the RCT. The findings from each iteration were used to inform the next iteration.

The first two years of the modelling horizon were assumed to have no generic new-build in order to reflect the minimum time required development and construction. After this two-year window, capacity is commissioned to meet the RCT in each year.

There were three major criteria used to inform the final mix of capacity:

1. Ability to meet system reliability targets (Unserved Energy below 0.002% of annual demand)
2. Facility types with the lowest net cost of new entry (net-CONE) prioritized over more expensive types
3. The choice of facilities is politically viable, and unlikely to be met with additional regulation (not all required capacity can come from gas)

The net-CONE approach included all forms of revenue available to a facility such as:

- Energy market revenue
- Essential System Services revenue
- Reserve Capacity Market revenue

Our iterative analysis had several findings leading to our choice of generic new build:

- OCGTs and CCGTs have a relatively high net-CONE due to their inability to receive capacity credits[9]
- Solar thermal and biomass have a relatively high net-CONE due to high capital costs
- 2-hour batteries have a higher net-CONE than 4-hour batteries as they receive less capacity credits
- 4-hour batteries are currently the generation type with the lowest net-CONE, followed by 2-hour batteries, HEGTs, wind, and solar
- 4-hour batteries remain the cheapest technology type throughout the modelling horizon, however, they are not always sufficient to meet reliability requirements
- Intermittent renewables, and gas are required alongside batteries to ensure system reliability with high demand growth.

[9] https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-investment-certainty-review

- In early years HEGTs, wind, and solar have a similar net-CONE and are suitable candidates for new build provided the share of each capacity type is balanced
- The profitability of solar generation decreases around 2030, as peak demand shifts toward later in the day, reducing energy revenues and capacity credit allocations.
- In later years, HEGTs and wind are the most viable new build technology to supplement 4-hour batteries

The results of our iterative process are shown in the following new build profiles:

Figure 5: Expected scenario generic new build (cumulative MW)

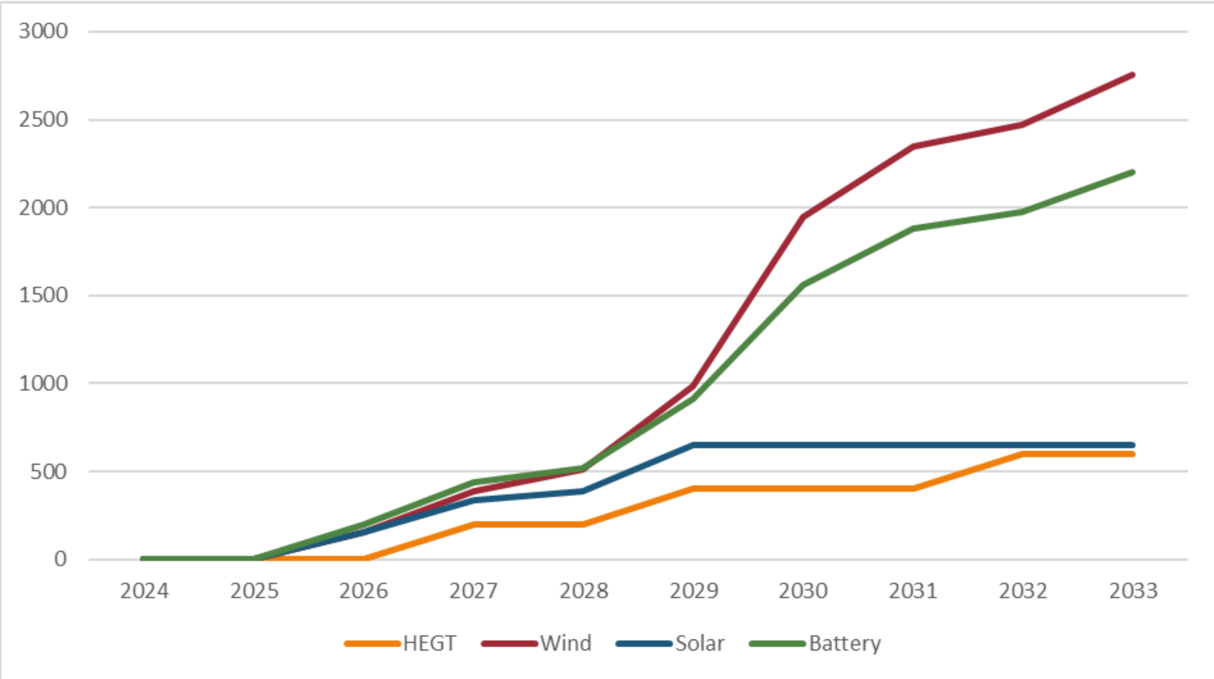


Figure 6: Low scenario generic new build (cumulative MW)

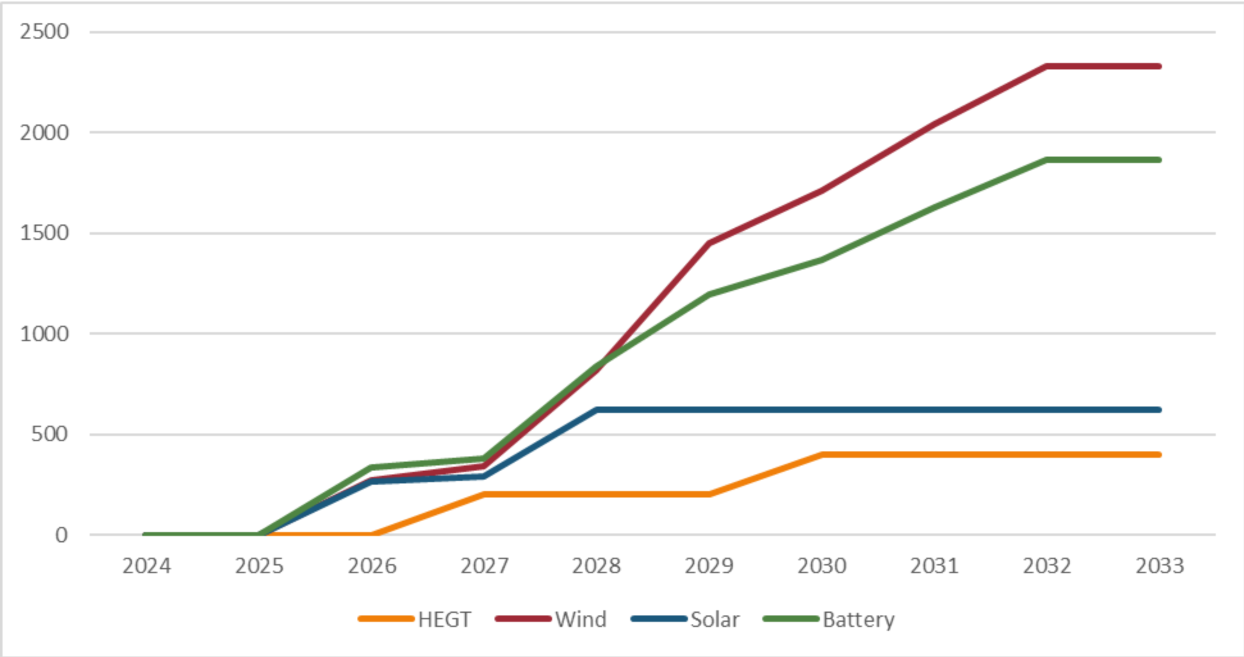
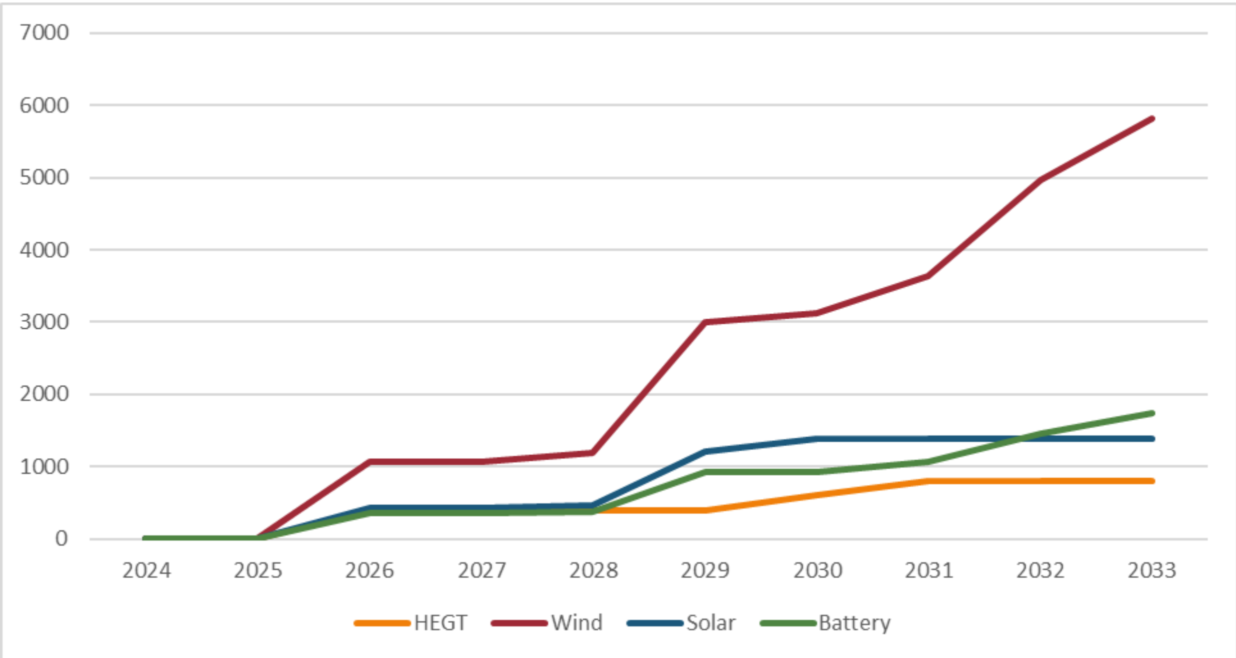


Figure 7: High scenario generic new build (cumulative MW)



2.1.6 Utility-Scale Intermittent Profiles

Treatment of intermittent generation

We have reapplied the methodology used in previous years[10] to derive intra-day hourly profiles for each month for each intermittent utility-scale facility[11]. This has resulted in 12 intra-day profiles for each of the 24 specific intermittent Facilities.

Generic, and new intermittent generation

When modelling intermittent generation for which no historical profiles are available, a combination of sources is utilized, in order of preference:

1. Expert reports
2. Scaled output of similar facilities in the region (e.g. capacity factor of locationally close existing facility * maximum capacity of new facility)
3. Average capacity factors of capacity type (e.g., average capacity factor of all wind turbines * maximum capacity of new facility)

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10 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.

11 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 for this assignment).

Capturing intermittent variability

As WEMSIM cannot set different intermittent output values for each modelled period, hourly monthly average profiles are used. This has the unintended effect of smoothing intermittent output. To reduce smoothing and reflect intermittent facilities' volatility additional outages were applied.

Historic periods where a facility's capacity factor was less than 2% of its nameplate were identified and used to set forced outage rates for intermittent facilities.

2.1.7 Outages

Forced outages

We will use updated forced outage assumptions for this assignment. These will be developed from analysing historical forced outage rates (FORs) over a 36-month period.

As our modelling software only enables full outages, we have created a full FOR equivalent combining partial and full outage rates. We have assumed a FOR of 0.1% for facilities with a zero historic FOR. 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.

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 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

For this assignment, AEMO provided RBP with participant provided planned outage schedules from 2023 to the end of 2036. This data includes both partial and full outages. Relevant facilities' capacity will be reduced on dates where a participant has indicated an outage.

2.1.8 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 plants.

AEMO-supplied constraints

Specific facility constraints have been implemented based on advice provided by AEMO. These constraints include minimum loads and monthly shutdowns.

To further enhance the accuracy of the model, we performed benchmarking against SCADA data. Dispatch of the major plants was compared to SCADA data of actual dispatch. From this analysis, minimum and maximum annual generation constraints were placed on large facilities. 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.

2.2 Transmission Network and Constraints

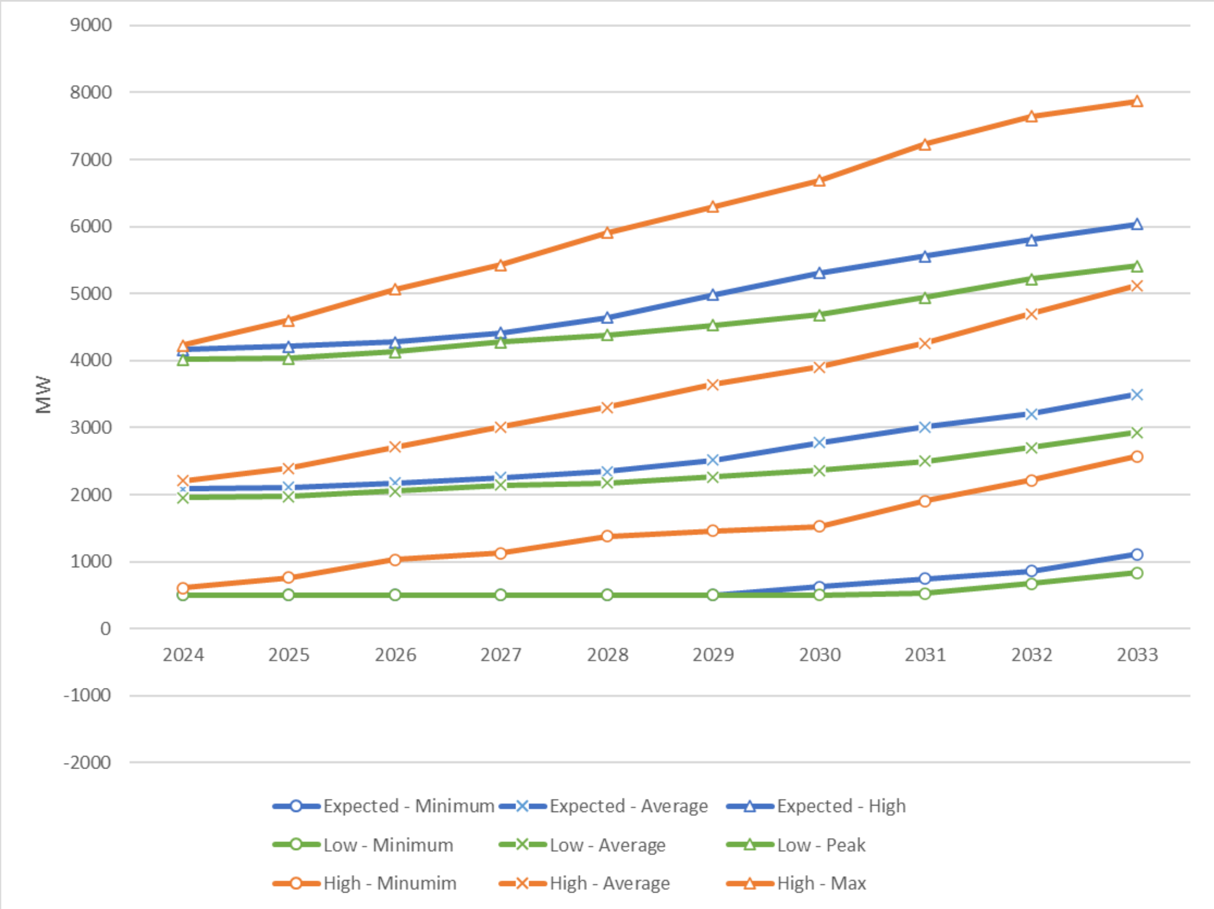
Security Constrained Economic Dispatch commenced in the WEM (SCED) on 1 October 2023. AEMO operates a dispatch algorithm to determine the least cost method to dispatch Facilities with a reference node located at Perth Southern Terminal to meet demand, while respecting Network Limits and maintaining power system security and issues corresponding dispatch instructions facilities.

The GSOO horizon comprises 2024 to 2033. Hence, we assume that SCED will apply for all periods. This takes the form of a single zone hub and spoke market with the reference node at Southern Terminal. The set of constraints used in this modelling is the same set used in the 2023 WEM ESOO. Specifically, simplified system-wide load coefficients are used as opposed to regional load coefficients.

2 DEMAND

AEMO provided all demand data. All scenarios used the half-hourly operational demand profiles developed from the 2023 WEM ESOO reliability assessment. Three reference capacity years were chosen: 2019, 2020, and 2021.

Figure 8: Operational demand



3 FUELS

Fuel prices will be specified in real 2023 AUD terms, so the market prices produced by the model will also be in Real 2023 AUD terms. Note that the fuel costs for fuels not listed in this section (landfill gas, waste, etc.) are assumed to be zero across all years.

3.1 PIPELINE NATURAL GAS

The prices for pipeline natural gas have been provided by AEMO for the purpose of this analysis.

3.2 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.

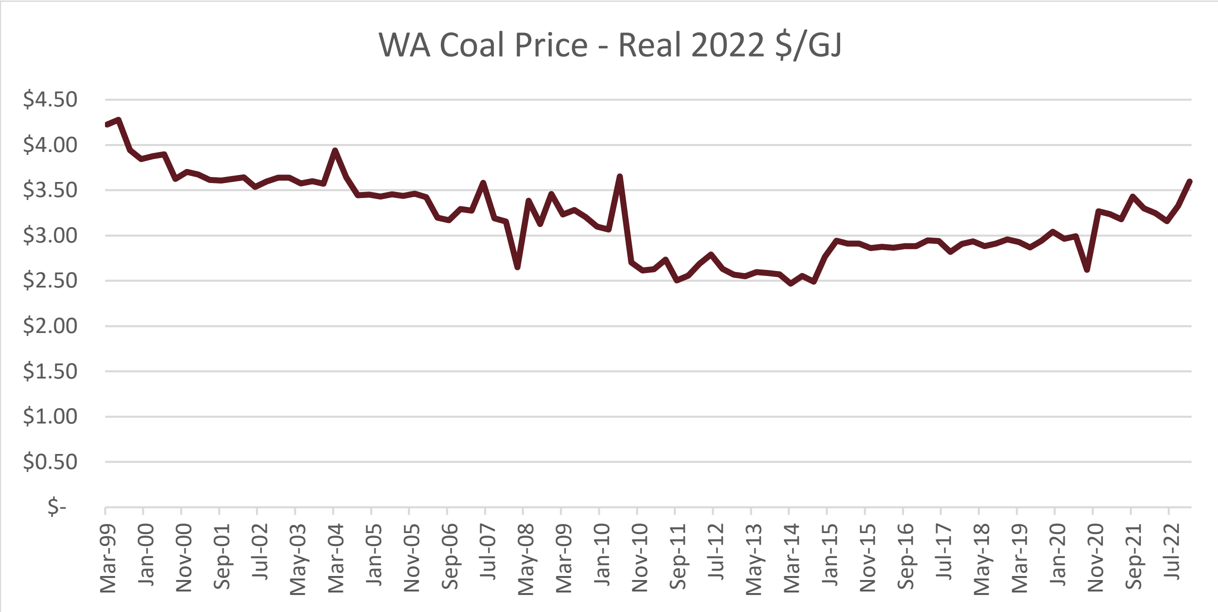
WA coal is not exported beyond WA, so does not receive global market prices.

Data on the value of WA coal is provided in the 2022 Major Commodities Resources Data, published by the Government of Western Australia Department of Mines, Industry Regulation and Safety[12]. This provides data on the quantity and value of coal produced in WA. Assuming a calorific value of 19.7 GJ/t[13], this yields the following historical prices:

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

13 Guide to the Australian Energy Statistics 2022: https://www.energy.gov.au/sites/default/files/Guide%20to%20the%20Australian%20Energy%20Statistics%202022.pdf

Figure 9. 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 2023 AUD terms) of the average price over the last 5 years. This results in a constant price of AUD $3.09/GJ.

Due to coal supply limitations, a maximum fuel offtake value was placed on coal based on coal generator capacity factors in the past two years. This amounted to a 66 TJ maximum annual offtake, which allowed the coal fleet to generate at an annual average capacity factor of around 60%.

3.3 Distillate

Historical "Perth Terminal Gate" prices for distillate (i.e., Diesel) are available from the Australian Institute of Petroleum[14]. 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 3.1), a distillate price forecast can be obtained as provided in Table 6.

14 https://www.aip.com.au/pricing/terminal-gate-prices/perthDiesel

Table 6. Distillate price forecast

Year	Expected (Real 2023 AUD/GJ)	Low (Real 2023 AUD/GJ)	High (Real 2023 AUD/GJ)
2024	18.79	16.96	20.17
2025	17.19	15.13	20.62
2026	16.50	14.22	20.62
2027	15.82	14.22	20.85
2028	15.82	14.22	20.85
2029	15.82	14.22	21.08
2030	15.82	14.22	21.08
2031	15.82	14.22	21.31
2032	15.82	14.22	21.54
2033	15.82	14.22	21.54

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[15]

Transport cost to Parkeston area is 1.1 c/l

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

4 Essential System Services

In all years we will model four Essential System Services: Contingency Reserve Raise, Frequency Contingency Reserve Lower, Regulation Raise, and Regulation Lower. AEMO provided us with the ESS formulation which is treated as a constraint within the dispatch equation of the WEM. However, as time limitations did not allow for us to incorporate the ESS formulation directly into our model's dispatch equation, the ESS formulation was instead used to calculate ESS requirements outside the model, before using the results to set minimum ESS values for each period. This required a preliminary run to estimate the largest contingency, before calculating each period's ESS requirements. As WEMSIM runs using patterns, these values were simplified into a set of 5760 (48*12*10, periods*months*years) unique values based on the half-hour, month, and year of the period.

5 Energy Storage

5.1 Distributed Energy Storage

Distributed energy storage charge and discharge are incorporated into the operational demand profile. Therefore, distributed energy storage facilities are not included in the model.

5.2 Grid-Connected Storage

WEMSIM tracks energy storage levels and determines an optimal charge/discharge profile for each storage facility. This is optimised to minimise overall costs for energy and ancillary service provision. There is no predetermined charge/discharge profile.

6 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 7:

Table 7. Scenario definitions

Scenario	High	Expected	Low
Operational consumption	High	Expected	Low
Peak demand	High case - 10% probability of exceedance (POE)	Expected case - 10% POE	Low case - 10% POE
Gas price	High	Expected	Low
Distributed PV and battery storage	High	Expected	Low
Bluewaters retirement	1-Oct-2026	1-Oct-2030	1-Oct-2030

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.

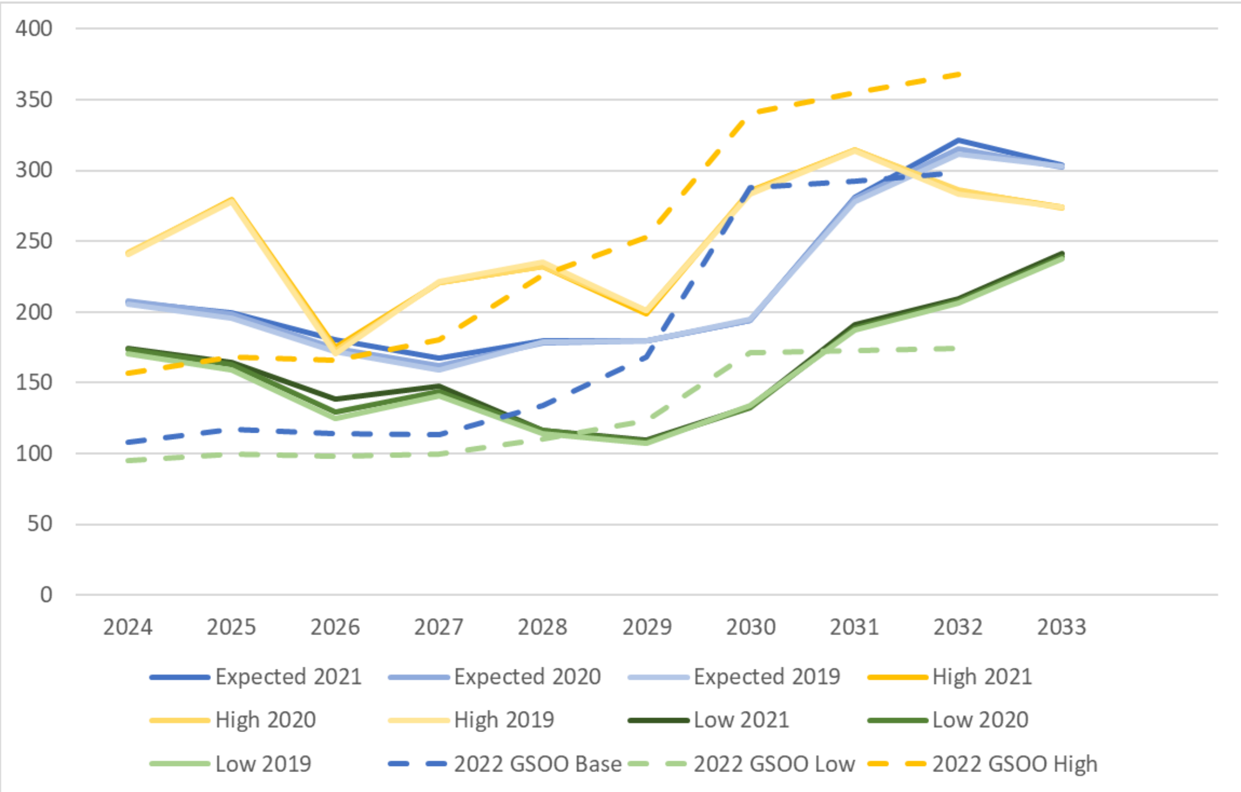
In the following sections, we provide summaries of the following results on an annual basis:

- Gas consumption
- Coal consumption
- Carbon emissions

3.1 Gas consumption

Figure 10 shows the annual total gas consumption from GPG from the model results (on a calendar year basis). Gas consumption from the 2022 GPG forecasts is included for comparison.

Figure 10: Gas consumption (TJ/day)



Compared to the 2022 GPG modelling results, gas demand is higher for the first 5 years of the modelling horizon. This is the result of a combination of factors:

- Coal offtake limits require greater gas consumption

- Greater variability in intermittent profiles requires gas to bridge gaps
- Higher demand growth

From 2029 onwards gas demand increases in all scenarios, as it did in the 2022 GPG results. However, the increase occurs one year later due as the retirement of Bluewaters being pushed back one year.

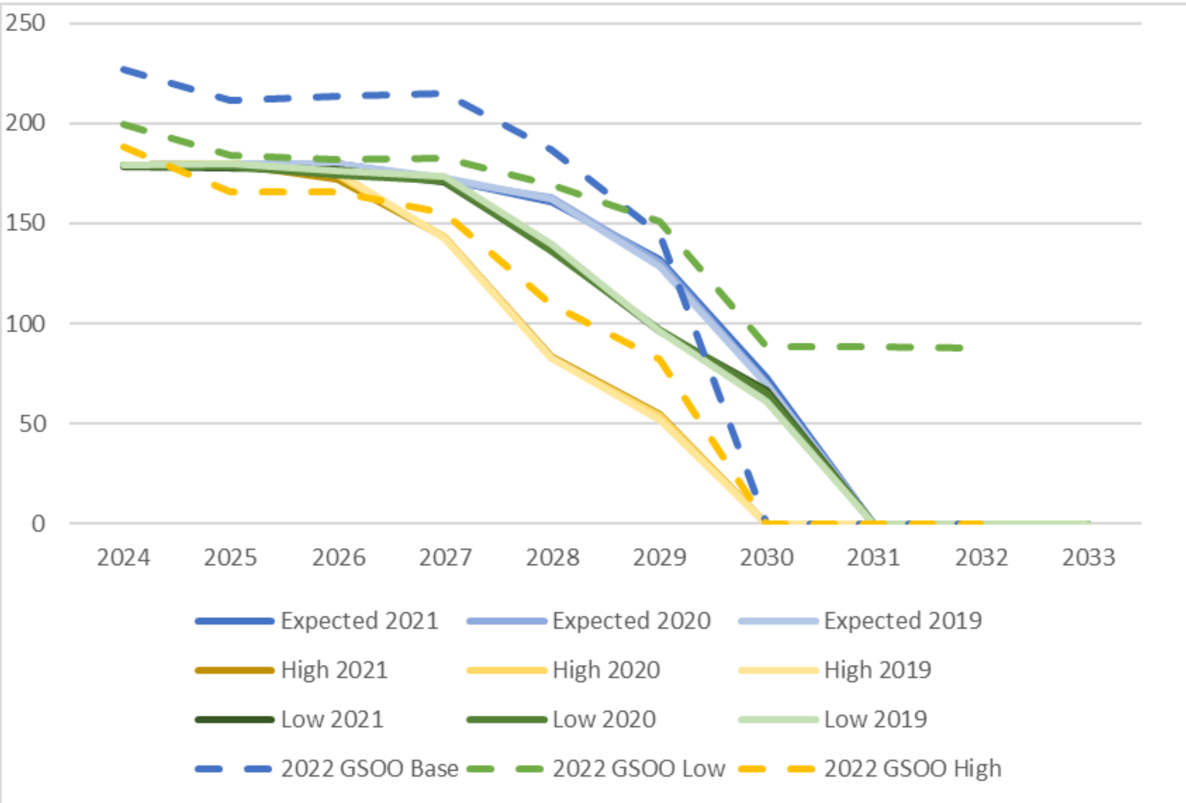
In the Low scenario, gas consumption increases after 2031 due to the complete retirement of all coal capacity, whereas the 2022 GPG results retained some coal capacity in the Low scenario.

The High scenario exhibits greater year-to-year volatility in gas consumption and drops below the expected scenario in the final two years due to the higher level of renewables new build (see the following section on emissions results).

3.2 Coal Consumption

Figure 11 shows the annual total coal consumption for electricity generation from the model results.

Figure 11: Coal consumption (TJ/day)



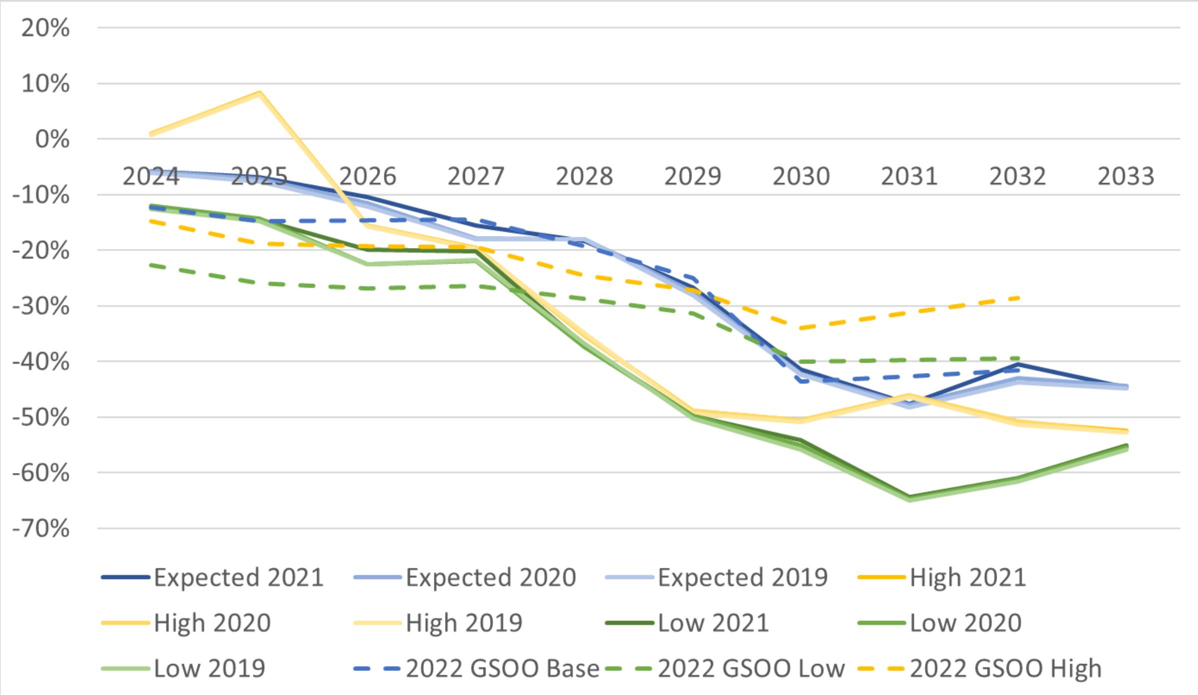
Compared to the 2022 GPG modelling results, Expected and Low scenarios' coal usage is mostly lower for the first 6 years of the modelling horizon. This is due to a limit placed on the availability of coal. Different retirement schedules, and an increase in renewable generation also influence the 2023 results, dropping consumption below that of the 2022 modelling.

The main difference between coal consumption in this year's scenarios comes from differences in retirement schedules. By 2031 coal facilities have retired in all scenarios.

3.3 Emissions

Figure 12 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 12: Emissions



Relative to the 2022 GPG modelling results, Expected Scenario emissions are very similar with the exception of the first 2 years. This small difference primarily stems from constraints on building new facilities during the first two years of the modelling horizon. The constraint is attributed to necessary development time for these facilities, leading to increased gas usage to meet demand. A similar pattern is also observed for the Low scenario. This limitation on new generation also explains the very high emissions in the first two years of the High scenario, where large increases in demand cannot be met by renewable intermittent generation.

The High scenario has lower emissions than the Expected scenario for the following reasons:

- The High scenario’s annual consumption to peak demand ratio was higher than other scenarios. This meant that generic new build batteries were less useful as there was insufficient energy to charge them leading up to system stress events. For this reason, more wind, solar and gas were built to ensure sufficient resources in peak events. The comparative increase in renewable generation, and displacement of coal with gas dropped overall emissions.
- Bluewaters retires in 2026 instead of 2030.

Overall, when compared to the 2022 analysis, the 2023 analysis shows greater volatility in emission reduction between scenarios due to greater differences in the generic new build installed in each scenario. Similarly, the overall emissions profile is lower, reflecting a significant amount of new renewable generation installed over the 10-year period. This contrasts with the 2022 analysis’ reliance on new build batteries.

4 CONCLUSIONS

4.1 KEY INSIGHTS

The most significant factor affecting results relative to the 2022 forecasts are:

- A limit on coal offtake which increases gas consumption in earlier years
- Higher demand forecasts increasing the requirement for generic intermittent capacity in the model

In the short-term gas generation is likely to drop slightly or plateau as new capacity enters the market.

In the long term, the retirement of coal increases the demand for gas generation which is required to meet peak demand and support renewables in long, dark, and still weather conditions.

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[16]). 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

[16] 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.

do not expect significant impacts on a system-wide level, so this will not affect the insights and results presented above.

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.

GLOSSARY

Table 8 presents a glossary of the terms used in this report:

Table 8: 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.