2022 Forecasting Assumptions Update

August 2022

For the 2022 National Electricity Market Electricity Statement of Opportunities and its Reliability Forecast

Important notice

Purpose

AEMO publishes this 2022 Forecasting Assumptions Update pursuant to National Electricity Rules (NER) 4A.B.1(e) and the Australian Energy Regulator's Forecasting Best Practice Guidelines (FBPG). This report includes information on updated assumptions to apply in the Reliability Forecast (and other publications, as named in this report, for the National Electricity Market (NEM)).

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Version control

Version	Release date	Changes
1.0	31/8/2022	Initial release

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Executive summary

AEMO delivers a range of forecasting and planning publications for the National Electricity Market (NEM), including the *Electricity Statement of Opportunities* (ESOO) and the *Integrated System Plan* (ISP). Key inputs and assumptions for the ISP are published at least biennially as part of the *Inputs, Assumptions and Scenarios Report* (IASR). The most recent IASR, used to prepare the 2022 ISP, is the 2021 IASR[1].

Many of the same inputs and assumptions are applied in preparing the NEM ESOO and the *Gas Statement of Opportunities* (GSOO), which are produced annually.

This report therefore complements the 2021 IASR and provides updated assumptions for inputs for the 2022 ESOO.

While some individual assumptions in this 2022 *Forecasting Assumptions Update* have changed since the 2021 IASR, as outlined in this report, AEMO does not consider the collective impact of the changes to be sufficiently material to lead to any alternative conclusion regarding the 2022 ISP or the selection of its optimal development path or the need for, or the characteristics of a current actionable ISP project.

Summary of updated assumptions

This *Forecasting Assumptions Update* and associated 2022 *Forecasting Assumptions Update Workbook* (the Updated Assumptions Book) outline updates to various forecasting components. The updates reflect both:

- Updated component forecasts that have been prepared in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines (FBPG)[2], and
- Re-baselined elements to reflect the latest actual market observations.

Forecasting components that reflect updated drivers and forecasts (rather than changes based on more recent actual observations) include:

- Updated generation developments based on the most recent issue of the Generation Information dataset[3].
- Updated gas prices (based on forecasts used in the 2022 *Gas Statement of Opportunities* [GSOO]).
- Updated technology costs, including for hydrogen electrolysers (developed for the annual CSIRO GenCost publication, the latest version of which was finalised in July 2022).
- Updated technical parameters associated with new and existing generation technology and hydrogen electrolysers, based on Aurecon's 2021-2022 AEMO costs and technical parameters review.
- Updated transmission network representations to reflect the 2022 ISP, 2022 marginal loss factors and other advice provided by relevant transmission network service providers.

[1] At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en.

[2] At https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

[3] See the July 2022 issue, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

1 Introduction

AEMO produces several publications that use inputs, assumptions and scenarios that are detailed in the *Inputs, Assumptions and Scenarios Report* (IASR). These publications include the *Electricity Statement of Opportunities* (ESOO), the *Gas Statement of Opportunities* (GSOO), and the *Integrated System Plan* (ISP). These publications complement each other, providing adequacy assessments of the electricity and gas systems, as well as optimal developments needed within the power system to provide energy consumers a path to a transformed reliable, low cost, net zero emissions future National Electricity Market (NEM).

AEMO uses a scenario analysis approach to:

- Investigate the various uncertainties facing the energy sector.
- Assess supply adequacy.
- Identify the economically efficient level of infrastructure investment necessary to support the future energy needs of consumers in the presence of uncertainty and risks of over- or under-investment.

This 2022 *Forecasting Assumptions Update* outlines several updated inputs that apply to the 2022 ESOO. In many instances, assumptions applied in the ESOO are unchanged since the *2021 Inputs, Assumptions and Scenarios Report* (IASR). This 2022 *Forecasting Assumptions Update* complements the biennial IASR, which provides the broader assumptions deployed across AEMO's forecasting and planning activities, including the ISP. Inputs that have not been updated since the 2021 IASR are not repeated in this publication.

The information in this report is supported by the 2022 *Forecasting Assumptions Update Workbook* (the Updated Assumptions Book)[4], which provides more granular detail for these updated inputs and assumptions.

All dollar values provided in this report are in real July 2021 Australian dollars unless stated otherwise.

1.1 Consultation process

In accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines (FBPG)[5], AEMO has consulted with stakeholders transparently and openly regarding the updated assumptions in this *Forecasting Assumptions Update*. Table 1 summarises the consultation activities undertaken for this purpose.

AEMO received formal submissions from nine stakeholders to the Draft Forecasting Assumptions Update consultation, including the ISP Consumer Panel. Key themes of the feedback included:

- AEMO's general scenario development and use of scenarios should incorporate a wider range of possible futures. Scenarios should also be revisited to align with Draft ISP outcomes, and further consultation should occur before any further scenario development.
- AEMO's scenario development should recognise uncertainty regarding hydrogen. There was a suggestion to add a high hydrogen price sensitivity to relevant scenarios.

[4] Also at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[5] At https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

AEMO documented its consideration of the stakeholder feedback in its 2022 *Forecasting Assumptions Update Consultation Summary Report*[6].

Table 1 Stakeholder engagement on the *Forecasting Assumptions Update*

Event/milestone	Date
FRG presentation and discussion on gas prices	24 November 2021
Publication of the draft Forecasting Assumptions Update and GenCost, and call for stakeholder submissions	20 December 2021
FRG Consultation on Unplanned Transmission outages methodology	27 January 2022
Submissions due on draft Forecasting Assumptions Update	4 February 2022
Submissions published	4 March 2022
Consultation Summary Report published	13 April 2022
FRG Consultation on Unplanned Transmission outages rate forecasts	29 June 2022
FRG Consultation on generation forced outage rate forecasts	29 June 2022
Final GenCost report published	11 July 2022
Publication of the final Forecasting Assumptions Update	This document, published with the ESOO

1.2 Approach taken to update key forecasting inputs

Two forms of updates have been applied in the updated assumptions since the 2021 IASR:

- **Updated** assumptions: reflecting holistic updates since the 2021 IASR, applying the same, or similar, methodologies to derive the new component forecast(s).
- **Rebased** assumptions: reflecting an updated starting point for the 2021 IASR scenario-based trajectories or trends, rebased to apply more recent actual data.

This *Forecasting Assumption Update* outlines the method for each assumption update in each subsection. All other component forecasts remain unchanged since the 2021 IASR.

1.3 Scenarios in this *Forecasting Assumptions Update*

This 2022 *Forecasting Assumptions Update* relates to scenarios from the 2021 IASR. In the case of *Hydrogen Superpower*, as proposed in the Draft Forecasting Assumptions Update consultation, the scenario is renamed to *Hydrogen Export* and may reflect an alternative underlying narrative in future, to be consulted on with stakeholders as part of the 2023 IASR development process. For this 2022 *Forecasting Assumptions Update* the scenario remains consistent with the 2021 IASR.

The *Forecasting Assumptions Update* consultation sought feedback on a potential green gas scenario. This feedback will be considered further for the 2023 IASR development process.

Refer to the 2021 IASR[7] for the scenario descriptions.

[6] At https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-forecasting-assumptions-update-consultation-summary.pdf.
[7] At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf.

1.4 Supporting material

Table 2 documents additional information related to AEMO's inputs and assumptions.

Table 2 Additional information and data sources

Organisation	Document/source	Link
AEMO	2021 *Inputs, Assumptions and Scenarios Report*	https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf
Aurecon	2021 Cost and Technical Parameter Review	https://aemo.com.au/consultations/current-and-closed-consultations/2022-consultation-on-forecasting-assumptions-update
CSIRO	Draft and final GenCost 2021-22	Draft: https://doi.org/10.25919/k4xp-7n26 Final: https://doi.org/10.25919/swn8-z583
Lewis Grey Advisory	Lewis Grey Advisory Fuel Prices	https://aemo.com.au/consultations/current-and-closed-consultations/2022-consultation-on-forecasting-assumptions-update

2 Updated assumptions

2.1 Historical data affecting forecasting components

Input vintage	**Updated** since the 2021 IASR • March 2022 for inputs affecting consumption and demand • May 2022 for transmission loss data • July 2022 for Generation Information • [April/May] for Forced Outage data
Source	• SCADA/EMMS/NMI Data • Generation Information page • AER and network operators
Updates since Draft IASR	Updated to use latest available information.

AEMO uses a range of historical data, used to train and develop its forecasting models, and consultant forecasts of various demand and energy consumption components, to deliver the overall Forecasting Approach[8]. Historical data is updated at varying frequency, from live metered data to monthly, quarterly, or annual updates depending on the forecasting component. Key historical datasets include:

- Metered electricity and gas consumption.
- Distributed photovoltaics (PV) uptake, and other distributed energy resource information.
- Other non-scheduled generators.
- Estimated network loss factors.
- Outage information regarding scheduled and significant non-scheduled generators.
- Weather data (such as temperature and humidity levels, solar irradiance and wind speed data) influencing demand, distributed PV generation and other renewable energy sources.

Information on datasets updated or rebased is outlined in the following sub-sections.

Historical weather data

AEMO uses historical weather data for training the annual consumption and demand models as well as to produce traces of historical consumption across AEMO's reference year collection. The historical weather data comes from the Bureau of Meteorology (BoM)[9], using a subset of the weather stations available in each region, as shown in Table 3.

AEMO selected these weather stations based on data availability and correlation with regional consumption or demand. AEMO uses one weather station per region, except where weather stations have been discontinued.

[8] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

[9] Bureau of Meteorology Climate Data, at http://www.bom.gov.au/climate/data/.

Table 3 Weather stations used in consumption, minimum and maximum demand

Region	Station name	Data range
New South Wales	BANKSTOWN AIRPORT AWS	1989/01 ~ Now
Queensland	ARCHERFIELD AIRPORT	1994/07 ~ Now
South Australia	ADELAIDE (KENT TOWN)	1993/10 ~ 2020/07
South Australia	ADELAIDE (WEST TERRACE)	2020/07 ~ Now
Tasmania	HOBART (ELLERSLIE ROAD)	1882/01 ~ Now
Victoria	MELBOURNE REGIONAL OFFICE	1997/10 ~ 2015/01
Victoria	MELBOURNE (OLYMPIC PARK)	2013/05 ~ Now

Operational demand

Operational demand as-generated is collected through the electricity market management system (EMMS) by AEMO in its role as the market operator.

Operational demand as generated includes generation from scheduled generating units, semi-scheduled generating units, and some non-scheduled generating units[10].

Generator auxiliary load

Estimates of historical auxiliary load are determined by using the auxiliary rates provided by participants in the Generation Information page. This is used to convert between operational demand as-generated (which includes generator auxiliary load) and operational demand sent-out (which excludes this component).

Network losses

The AER and network operators provide AEMO with annual historical transmission loss factors. The AER also provides AEMO with annual historical distribution losses which are reported to the AER by distribution companies. AEMO uses the transmission and distribution loss factors to estimate half-hourly historical losses across the transmission network for each region in megawatts (MW) or megawatt hours (MWh).

Large industrial loads

AEMO's *Electricity Demand Forecasting Methodology* defines a methodology for identifying large loads for inclusion in the large industrial load (LIL) sector. AEMO collects the historical demand of these LILs from National Metering Identifier (NMI) metering data.

Residential and business demand

The split of historical consumption data into business and residential segments is performed using a combination of sampling of AEMO residential meter data and annual ratios between the two segments provided by electricity distribution businesses to the AER as part of their processes in submitting a regulatory information notice. Further details of the approach are in Appendix A6 (residential-business segmentation) of the *Electricity Demand Forecasting Methodology*.

[10] A small number of exceptions are listed in Section 1.2 of https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/2020/demand-terms-in-emms-data-model.pdf.

Distributed PV uptake and generation

AEMO sources historical PV installation data from the Clean Energy Regulator (CER) and applies a solar generation model to estimate the amount of power generation at any given time. The Distributed Energy Resources (DER) Register[11] is used for validating the historical PV installation data.

Other non-scheduled generators

AEMO reviews its list of other non-scheduled generators (ONSG) – non-scheduled generation that excludes distributed PV[12] – using information from AEMO's Generator Information dataset, the DER Register, and the Demand Side Participation (DSP) Information Portal. These datasets are complemented with information provided from network operators and publicly available information. This *Forecasting Assumptions Update* includes updates to February 2022.

Through these sources of information, AEMO collects withdrawn, committed, and proposed ONSG connections and site information. AEMO uses the generator's Dispatchable Unit Identifier (DUID) or NMI to collect generation output at half-hourly frequency.

AEMO forecasts connections or withdrawal of ONSG generators based on firm commitment statuses of these generators in the short term and applying historical trends of ONSG by fuel type (for example, gas- or biomass-based cogeneration, or generation from landfill gas or wastewater treatment plants) in the long term.

AEMO's current view of ONSG is contained in the Generation Information page. As at the February 2022 release, which was used in the development of the demand and energy forecasts, aggregated ONSG by NEM region is shown in Table 4 (noting that changes to aggregated non-scheduled generation capacity since this release are minimal).

Table 4 Aggregate other non-scheduled generation capacity, by NEM region

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Installed capacity (MW)	474	503	61	131	321

2.2 Energy consumption and demand updates

AEMO updates its projections of energy consumption and demand at least annually[13], and includes significant stakeholder engagement through the Forecasting Reference Group[14] (FRG), industry engagement via surveys, and consultant forecasts, in accordance with the AER's FBPG. This engagement focuses on key influences and outcomes from AEMO's forecasting models within the Forecasting Approach of each sector and sub-sector affecting energy consumption and peak demands.

[11] At https://aemo.com.au/en/energy-systems/electricity/der-register.

[12] Distributed PV is discussed in Section 2.2.2.

[13] Updated forecasts within a year can be issued in case of material change to input assumptions.

[14] See https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

Table 5 Status and update for key inputs and assumptions

Input	Status
Historical data	Updated
Distributed energy resources (including distributed PV, distributed battery storage and electric vehicles [EVs])	Rebased for distributed PV and electric vehicles. (Battery storage remains unchanged)
Electrification of other sectors	Rebased
Economic and population, including connections	Rebased
Large industrial loads	Updated
Energy efficiency	Rebased
Appliance uptake	Rebased
Electricity prices	Updated
Demand side participation	Updated
Gas prices	Updated, as outlined in the Draft Forecasting Assumptions Update

2.2.1 Electrification

Input vintage	**Rebased** since the 2021 IASR
Source	• CSIRO and ClimateWorks Australia (multi-sector modelling) • CSIRO (road transport modelling)
Updates since 2021 IASR	Current electrification data has informed a rebasing of initial trajectories. A glide path adjustment has been applied. The electric vehicle forecast has been rebased to reflect latest vehicle sales trends.

Energy usage presently met from non-electric alternatives can be met with alternative energy sources, including electricity, through fuel switching. AEMO considers the potential electrification of Australia's economy, across the residential, business (comprised of commercial and industrial and other sectors), and transport sectors.

In the residential and commercial (building) sectors, appliances that service space heating, cooking, and hot water are all able to be electrified, shifting from gas or liquefied petroleum gas (LPG) demand into electricity demand. The cost-efficiency of electrification is uncertain and will depend on many factors including appliance replacement costs, electricity infrastructure capabilities and costs, and the availability of alternative fuels, such as hydrogen or blended hydrogen-natural gas. AEMO has therefore considered a range of electrification outcomes for these sectors, with the *Hydrogen Export* scenario applying greater hydrogen fuel substitution as an alternative to electrification.

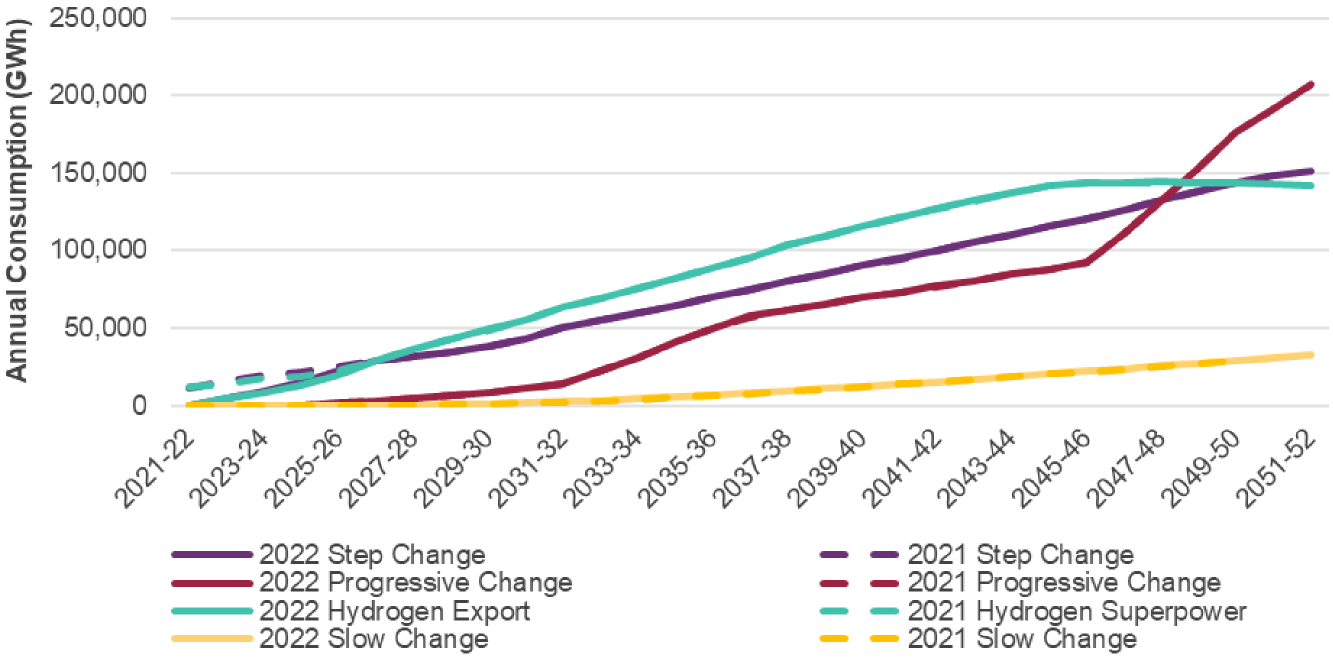
In the industrial sector there is a wide range of subsectors considered, each of which have their own fuel consumption profiles. Broadly speaking, while most oil and gas demands can be electrified (or switched to biofuels), many loads also exist that will be challenging to electrify for various reasons. Technological advances may be required to enable high-heat processes to electrify, such as the direct reduction process for iron and steel. For these processes it may be possible to convert from high temperature blast furnaces to lower temperature electric arc furnaces. Investment in these technological advances is assumed in scenarios with more ambitious emissions reductions, to help decarbonise more challenging industrial processes and lower broader economy costs associated with alternative investments or offsets.

Electrification of the transport sector is expected in all scenarios.

Figure 1 shows the total electrification across the modelled scenarios. As forecast for the 2021 IASR, 150 terawatt hours (TWh) of new electricity consumption is forecast in scenarios which assume coordination of activities to achieve net zero emissions economy-wide. These scenarios differ most in terms of timing of investment, with early investment leading to lower long-term electrification due to deeper inroads in emissions reduction.

In this *Forecasting Assumptions Update*, the scale of electrification has been rebased in the short-term, applying 10% of the 2021 ESOO electrification in 2022 (the base year of the forecast), and incrementally increasing over a five-year period to scale up to the 2021 IASR electrification forecast. This rebasing reflects slower electrification investment, as material electrification similar to the level forecast in 2021 is not yet observable.

Figure 1 Electrification of other sectors, demonstrating early-year rebasing of 2021 IASR forecasts



Note: for the *Slow Change* scenarios, the electrification shown is solely from EV uptake.

The impact of electrification on daily and seasonal load shape is further discussed in the 2021 IASR[15].

Electric vehicle uptake

Input vintage	**Rebased** since the 2021 IASR
Source	CSIRO, EV Council[16]
Updates since Draft IASR	Rebased to account for the latest EV adoption numbers as published by the EV Council.

Electrification of the transport sector will increase electricity consumption in future.

Key factors for EV adoption (including battery and plug-in hybrid EVs) and hydrogen-fuelled vehicles are outlined in the 2021 IASR, informed by CSIRO's *Electric Vehicle Projections 2021* report[17]. Key points of influence are:

[15] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[16] Known to be approximate only but considered by the EV Council to be a reasonable estimate.

[17] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-ev-forecast-report.pdf for more details.

- Government policies (see Sections 3.2.4 and 3.2.5 of the CSIRO report for policies included in the 2021 forecasts).
- Cost differences between EVs and internal combustion engine vehicles (ICEs).
- Substitutes and alternatives to EVs (such as public transport, rideshare services, and hydrogen fuel cell vehicles).
- Commercial fleet ownership.
- Access to charging infrastructure.
- The availability of different EV models and sizes in Australia.

For this *Forecasting Assumptions Update*, minor adjustments were made to EV uptake by rebasing the 2021 IASR forecast, based on more recent data from the EV Council up to end of 2021, increasing the EV count within the NEM by approximately 24,000 across the forecast period. The actual number of vehicles in the NEM was estimated to be approximately 50,000 as at end June 2022. This update has a relatively minor impact on the contribution of EVs to electricity consumption and demand over the forecast horizon. The rebased forecast does not impact EV charging behaviour assumptions described in the 2021 IASR[18].

More detail on the projected uptakes for each scenario is provided in the accompanying Updated Assumptions Book.

2.2.2 Distributed energy resources

Input vintage	**Rebased** since the 2021 IASR
Source	• CSIRO • Green Energy Markets • Clean Energy Regulator • Australian Photovoltaic Institute • AEMO's DER Register
Updates since 2021 IASR	PV model rebased with current data on distributed PV installations

DER describes consumer-owned devices that, as individual units, can generate or store electricity or have the 'smarts' to actively manage energy demand. This includes small-scale embedded generation such as distributed PV systems (including PV non-scheduled generation [PVNSG]), battery storage, and EVs.

As outlined in the 2021 IASR, AEMO engaged CSIRO[19] and Green Energy Markets (GEM)[20] to prepare independent forecasts of this important component. AEMO considers that forecast accuracy is improved by obtaining two independent models that are underpinned by the same assumptions and scenario narratives.

[18] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[19] See CSIRO: *Projections for small-scale embedded technologies*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-der-forecast-report.pdf.

[20] See Green Energy Markets: *Projections for DER – solar PV and stationary energy battery systems*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf.

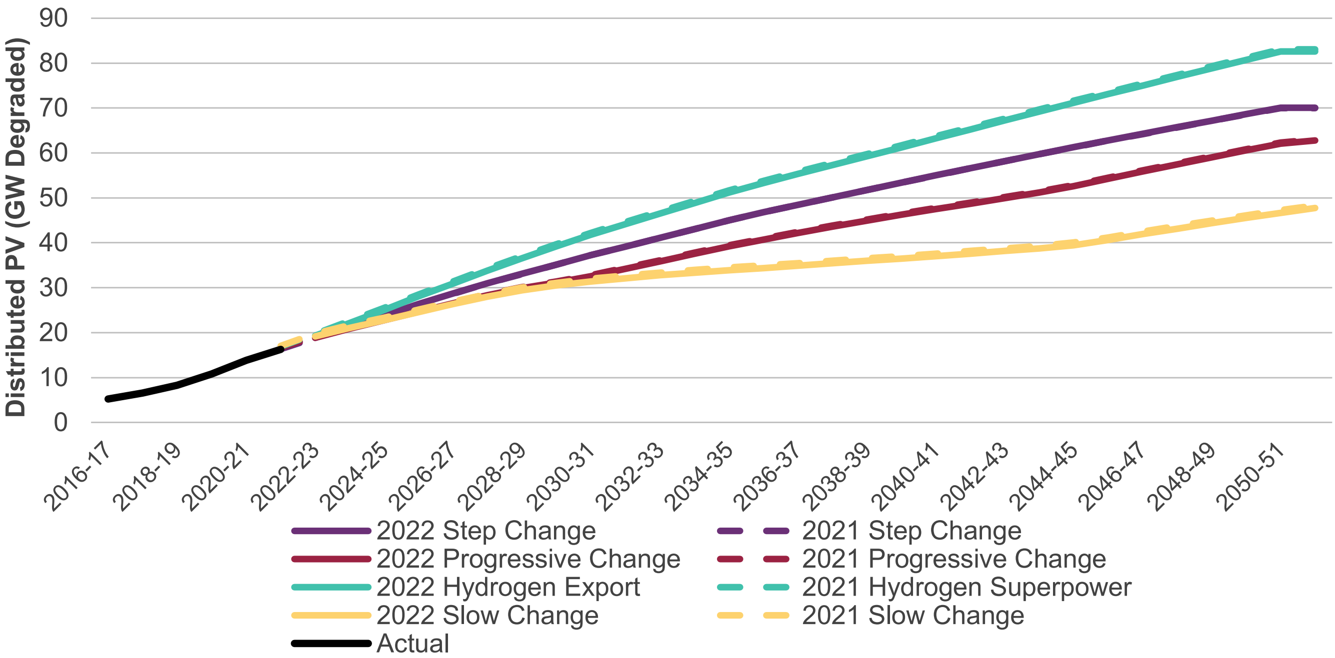
Distributed PV

Current distributed PV installed capacity estimates are from the CER. PVNSG installed capacity estimates are provided by the Australian Photovoltaic Institute (APVI), in the first instance, then bolstered by the CER.

AEMO has continued to apply the projected distributed PV uptake rate from the 2021 IASR rebased to reflect current installations. This Assumptions Update demonstrates a rebased forecast using the latest estimate of total installed capacity of distributed PV systems in the NEM from the most recent CER release, which is 16.3 gigawatts (GW) as of June 2022 as shown in Figure 2.

Details on CSIRO's and GEM's forecasting approach and outlook can be found in each consultant's report, referenced above.

Figure 2 NEM distributed PV installed capacity (degraded)



2.2.3 Economic and population forecasts

Input vintage	**Rebased** since the 2021 IASR
Source	• BIS Oxford Economics • ABS Population Series
Updates since 2021 IASR	Economic forecasts have been rebased using updated ABS National Accounts data

In 2021, AEMO engaged BIS Oxford Economics to develop long-term economic forecasts for each Australian state and territory as a key input to AEMO's demand forecasts.

The pandemic recovery has continued to dictate growth outcomes in the near-term outlook, with economic growth from the commercial and services sector driving economic recovery and growth following the pandemic-driven decline in 2019-20 and 2020-21. Beyond 2021-22, the construction and manufacturing sectors were expected to reap the benefit of government fiscal stimulus and account for increasing shares of economic activity in the medium term. This trend was forecast to be especially pronounced in Queensland, due to its' relative strength throughout the pandemic. As international borders reopened from 2021-22, hospitality and tourism sectors were forecast to see stronger growth outcomes through to 2023-24, after which growth is expected to return closer to trend. In the long term, service-intensive states like Victoria and New South Wales were forecast to benefit as the sectoral composition returns to its structural fundamentals and the services sector continues to gain an increasing share of economic output.

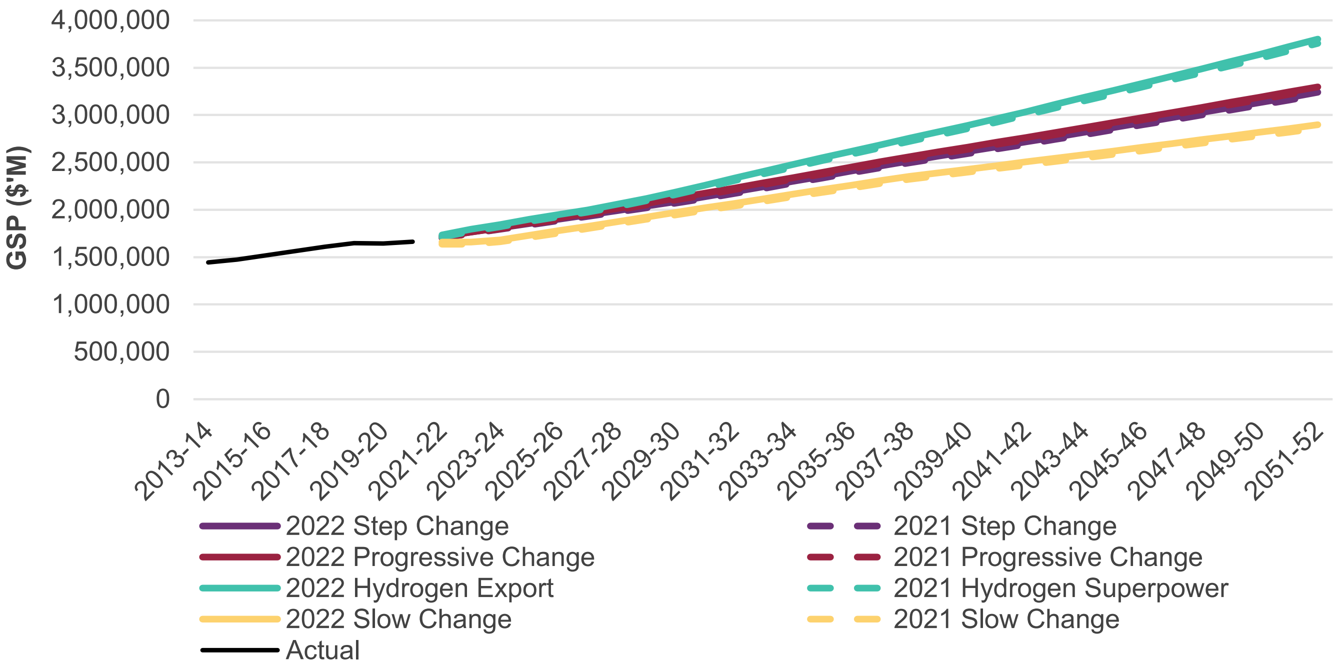
A range of economic outcomes were captured with the use of scenarios including, for example, a downside scenario featuring higher inflation (compared to the central scenario) and weaker growth in industries such as retail trade, reflective of a harsher economic climate.

Despite outperforming other developed countries in the early years of the pandemic, the Australian economy has been faced with significant inflationary pressures[21], with the pandemic recovery continuing and global production implications of the Russia-Ukraine conflict driving volatility and uncertainty. To capture some of these recent trends, the BIS Oxford Economics forecasts were rebased using the financial year 2020-21 Australian Bureau of Statistics (ABS) National Accounts release[22].

Figure 3 shows the forecast economic outcomes for gross state product (GSP) of the aggregated NEM regions, demonstrating the significance of the COVID-19 pandemic in flattening the GSP growth since 2020, and the uncertainty regarding the economic recovery that is captured across the dispersion between scenarios.

A breakdown of the relative economic activity of each sub-sector can be found in the 2021 IASR and 2021 BIS Oxford Economics Macroeconomic Projections Report[23].

Figure 3 NEM aggregated gross state product



[21] Driven by strong growth in the construction industry coupled with supply chain constraints across several key industries.

[22] The Financial Year 2020-21 ABS National Accounts release was used for rebasing, as it was the most recently available annual dataset at the time of rebasing. Available at https://www.abs.gov.au/statistics/economy/national-accounts/australian-system-national-accounts/latest-release.

[23] BIS Oxford Economics 2021 Macroeconomic Projection Report available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf?la=en.

Population growth is also a key driver of Australia's economic growth. No rebasing was required for the latest population forecasts, with population growth tracking close to the 2021 Centre for Population release[24]. More detail is available in the 2021 IASR.

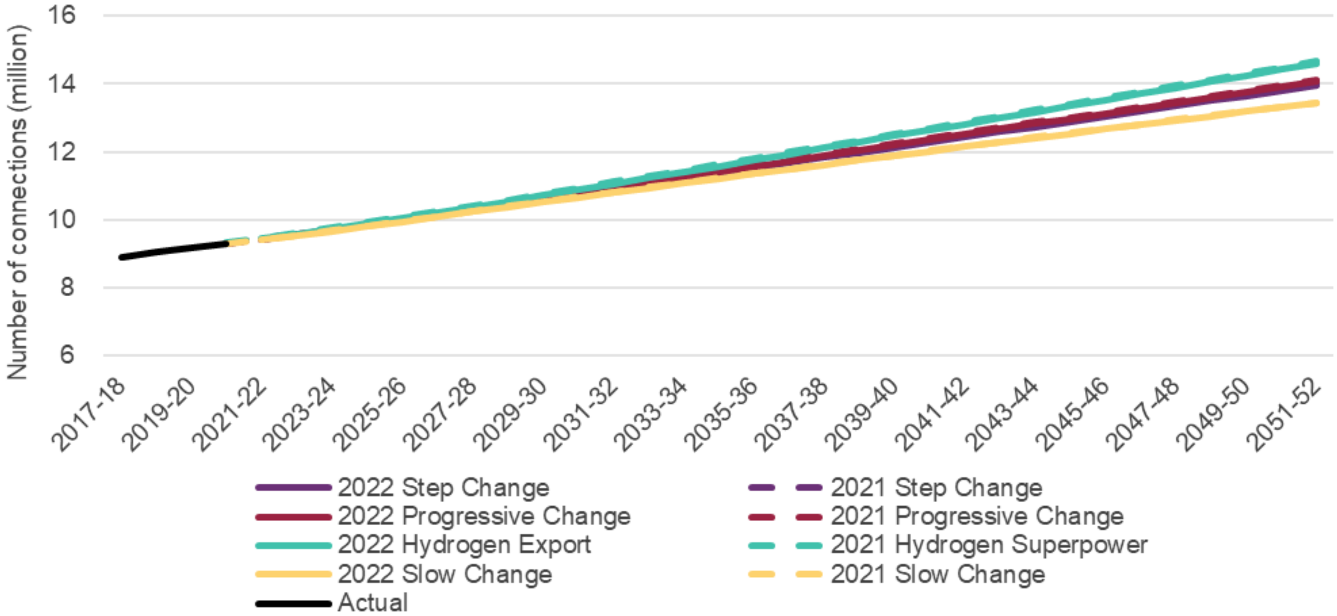
2.2.4 Households and connections forecasts

Input vintage	**Rebased** since the 2021 IASR
Source	• ABS • BIS Oxford Economics • AEMO meter database
Updates since 2021 IASR	Connections forecasts have been rebased with updated connections numbers in May 2022 Population forecasts are unchanged since the 2021 IASR

AEMO's forecast of the increase in residential electricity consumption is mainly driven by electricity connections growth.

AEMO's 2022 connections forecasts use the growth rate from the 2021 IASR, rebasing it with latest connections numbers attained from AEMO's meter database. The actual number of connections for 2021 is marginally lower than was forecast in the 2021 IASR. This has resulted in a small downward adjustment in the connections forecasts compared to the 2021 forecasts. The net impact of rebasing the forecasts is that by 2052 there are approximately 370,000 fewer connections than in the 2021 *Step Change* forecast. Figure 4 shows the residential connections actual and forecast for all scenarios.

Figure 4 2022 NEM residential connections actual and forecast, 2017-18 to 2051-52, all scenarios



[24] Centre for Population 2021 Population update available at https://population.gov.au/publications/statements/2021-population-statement.

2.2.5 Large industrial loads (LILs)

Input vintage	**Updated** in June 2022
Source	• Interviews/surveys with LILs including self-reported forecasts until 2052. • AEMO meter database • Distribution network service providers • (DNSPs) • Media search/announcements
Updates since 2021 IASR	Updated based on new survey data provided by large customers.

AEMO segments and forecasts LILs separately to small and medium commercial enterprises, as the broader econometric model used to forecast other business customers may not provide appropriate accuracy for these larger industrials that have more unique circumstances to the remainder of business customers.

AEMO identifies LILs by analysing AEMO's meter data and working with transmission network operators and distribution network operators for each region to find loads that demanded at least 10 MW for greater than 10% of the latest financial year. This threshold aims to capture the most energy-intensive consumers in each region.

AEMO currently sources information regarding LILs from:

- Surveys and interviews of identified LIL consumers,
- AEMO's standing data requests from distribution network service providers (DNSPs) regarding prospective and newly connecting loads.
- AEMO's metering data for transmission and distribution connected NMIs associated with the LILs.
- Media searches and company announcements.

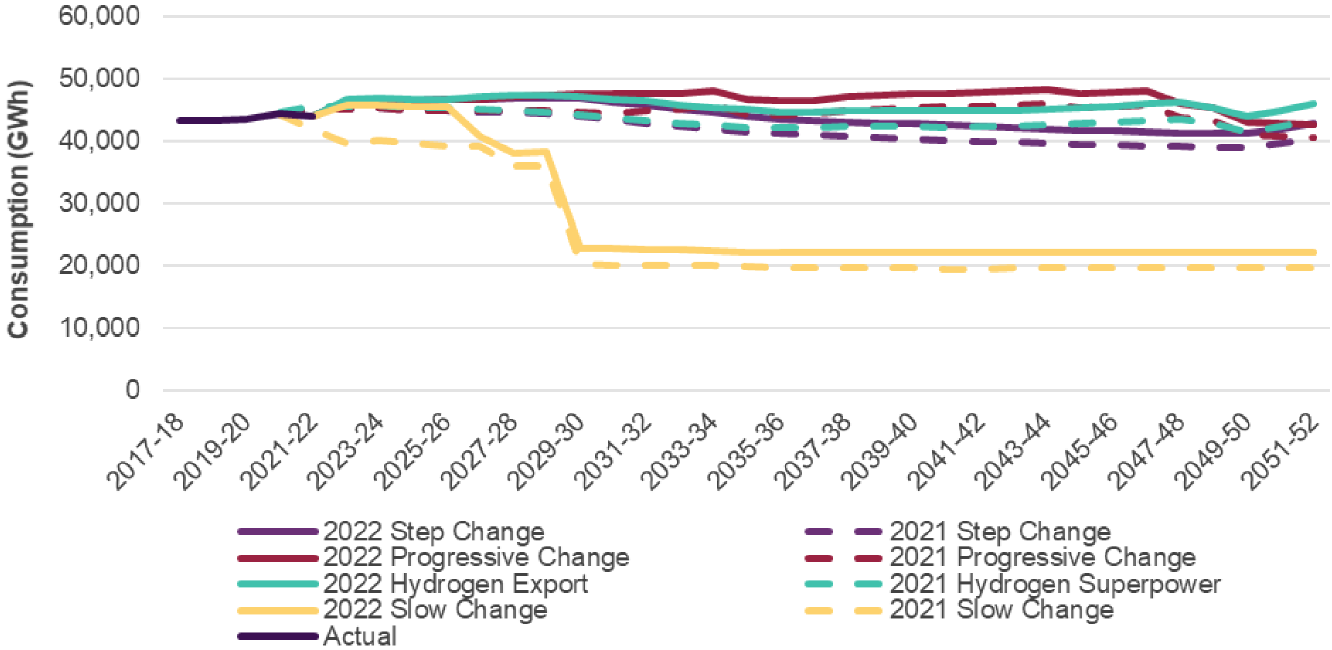
AEMO's 2022 LIL forecasts in the *Step Change* and *Hydrogen Export* scenarios are higher than 2021 *Progressive Change* and *Hydrogen Superpower* scenarios, driven by:

- the addition of coal mine sites in New South Wales and Queensland previously not identified as LILs (and included therefore in broader business consumption forecasts), and
- increased consumption forecasts for some existing LILs.

The 2022 *Slow Change* forecast is higher than in 2021 due to the lower risk of closure for some LILs in the short term (2022-26), increased consumption forecast for existing LILs and new sites added to the LIL list in the long term (after 2030).

The LIL consumption forecast for all scenarios is shown in Figure 5.

Figure 5 2022 NEM LIL consumption forecast, 2017-18 to 2051-52, all scenarios



Liquified natural gas

Input vintage	**Updated** in June 2022
Source	2022 GSOO surveys
Updates since 2021 IASR	Revised data from 2022 GSOO surveys

The LNG forecasts estimate the expected electricity consumption of the operations of coal seam gas (CSG) fields in the NEM by considering surveyed data provided by the LNG consortia, as per other LILs. This data considers the anticipated operating range of CSG facilities over the short term, between three and five years ahead.

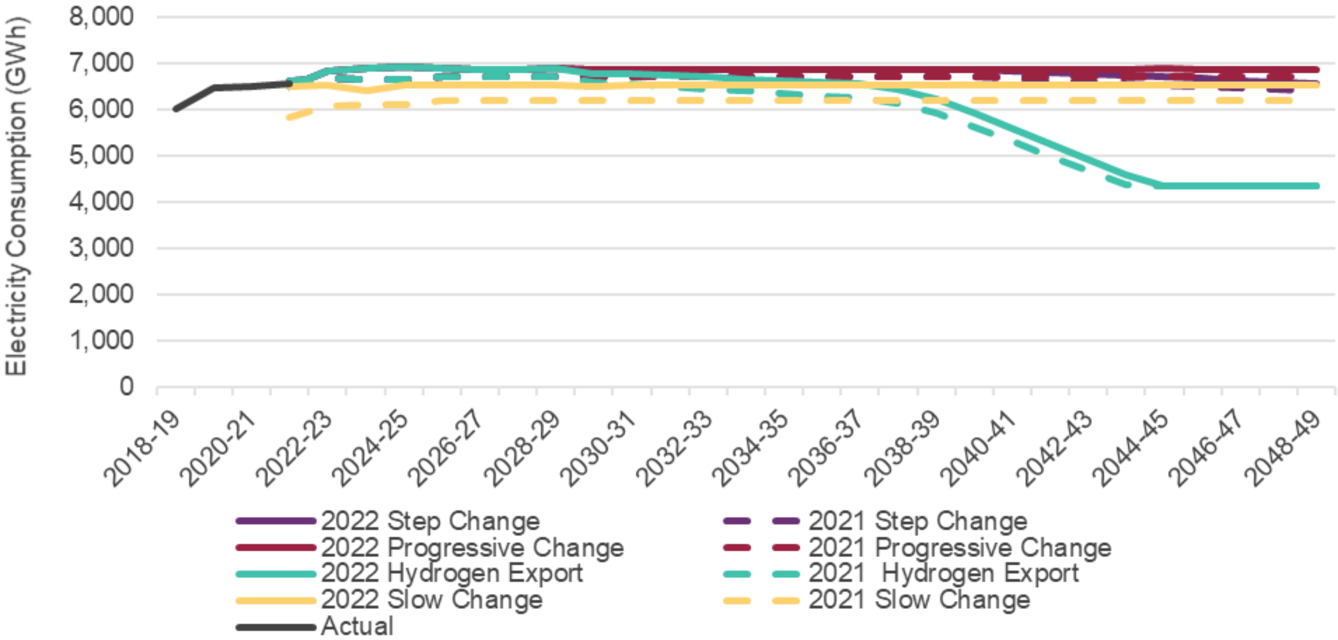
Queensland's LNG industry is a material consumer of electricity, consuming approximately 5% of AEMO's total business consumption category. Due to the significance of these loads, AEMO forecasts LNG loads in a similar manner to other LILs, but aggregates them separately from other LILs for improved transparency.

The international LNG market faces an uncertain future. Global demand for liquid fuels shifts as each country determines how it will achieve its own emissions reduction commitments, with some commentators predicting ongoing strong growth through to 2050, while others predicting a notable decrease[25]. For the NEM's LNG exports facilities in Queensland, AEMO considers that capacity expansion of the Curtis Island export facilities is not realistic in the ESOO horizon. The existing LNG export facilities already operate at high utilisation factors. AEMO therefore considers that the upper range of reasonable forecasts for LNG operations is for operations to continue at current high utilisation levels.

Figure 6 demonstrates the forecast range across AEMO's modelled scenarios. Similar to other LILs, LNG operators are surveyed to inform the updated forecasts. This survey process resulted in a minor increase compared to the 2021 IASR forecasts.

[25] The International Energy Agency outlined an uncertain future for LNG; see International Energy Agency (2021), *Net Zero by 2050: A roadmap for the Energy Sector*, at https://www.iea.org/reports/net-zero-by-2050.

Figure 6 LNG forecast electricity consumption, by scenario



2.2.6 Energy efficiency forecast

Input vintage	**Rebased** since the 2021 IASR
Source	• Strategy Policy Research • CSIRO/ClimateWorks
Updates since Draft IASR	An adjustment has been applied to the 2021 IASR energy efficiency forecasts for the higher scenarios to better reflect current energy efficiency trends Forecasts rebased to make 2021-22 the base year.

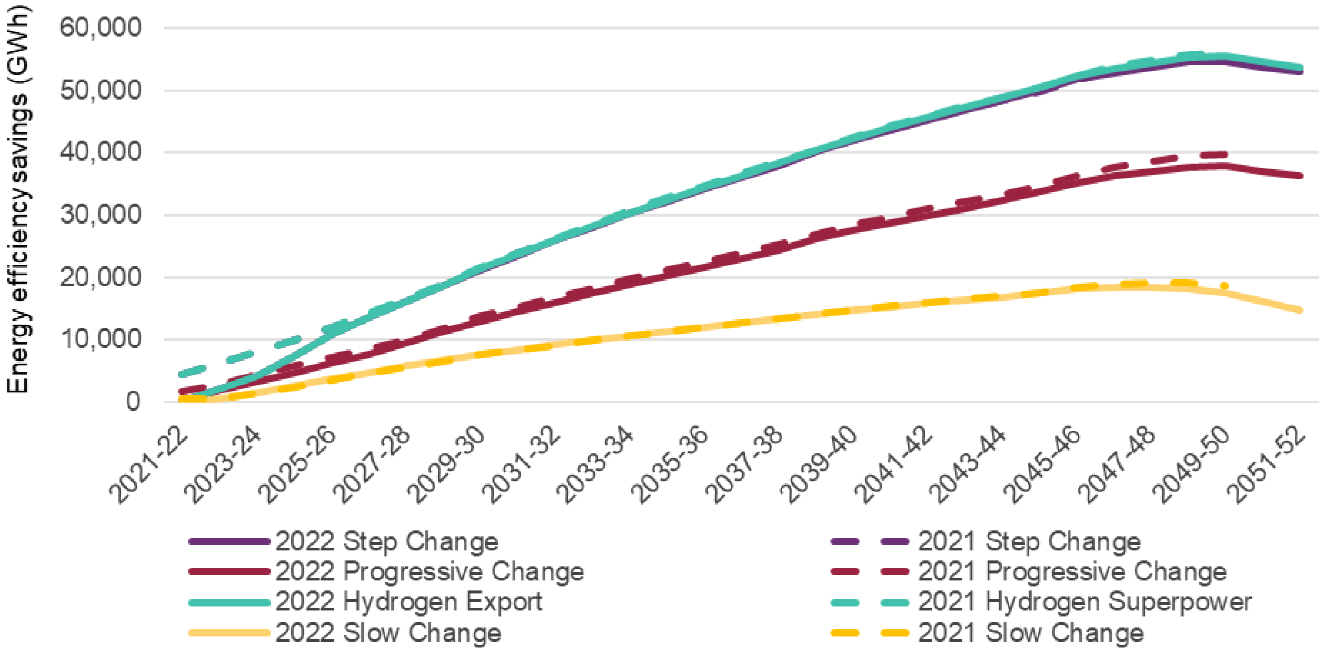
Australia's governments collectively have developed a range of measures to mandate or promote energy efficiency uptake across the economy. AEMO's energy efficiency forecasts, developed for the 2021 IASR and supported by *Strategy.Policy.Research* are influenced by the outcomes affecting economic, population, housing, and connections growth for each scenario. Policy differences across scenarios also inform energy efficiency forecasts for each scenario[26].

More information is available in Section 3.1 of the 2021 IASR.

Figure 7 shows the total energy efficiency applied to electricity consumption across the modelled scenarios. AEMO rebased these forecasts to reflect more recent estimates of actual consumption. *Step Change* and *Hydrogen Export* scenarios then revert to the 2021 forecast trend, with the savings becoming effectively equivalent to the 2021 forecasts within approximately five years.

[26] AEMO removes the future savings from activities that took place prior to the base year of the forecasts. For more information, see the *Electricity Demand Forecasting Methodology* information paper, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf.

Figure 7 Forecast energy efficiency savings, 2021-22 to 2051-52



Note: *Step Change* and 2021 *Hydrogen Superpower* and 2022 *Hydrogen Export* assume similar levels of energy efficiency.

2.2.7 Appliance uptake forecast

Input vintage	**Rebased** in April 2022.
Source	• Department of Energy and Environment Energy 2015 Residential Baseline Study for Australia 2000 – 2030, (RBS, 2015) available at www.energyrating.com.au. • State and Federal energy departments • Multi-sectoral modelling • Economic forecast
Updates since Draft IASR	Appliance uptake forecasts have been rebased making 2022 the base year

Electricity consumption forecasts consider policies and programs that induce fuel switching behaviour (between electricity and natural gas) through the energy efficiency forecasts and the residential sector's forecast of appliance growth.

As part of the 2021 IASR, AEMO used appliance data from the former Australian Government Department of the Environment and Energy (now the Department of Climate Change, Energy, the Environment and Water [DCCEEW]) to forecast the growth in appliances per connection in the residential sector. The data allowed AEMO to estimate changes to the level of energy services supplied by electricity per households across the NEM. Energy services here is a measure based on the number of appliances per appliance category across the NEM, their usage hours, and their capacity and size (Refer to Appendix A5 of AEMO's *Electricity Demand Forecasting Methodology*[27] for details on the methodology used).

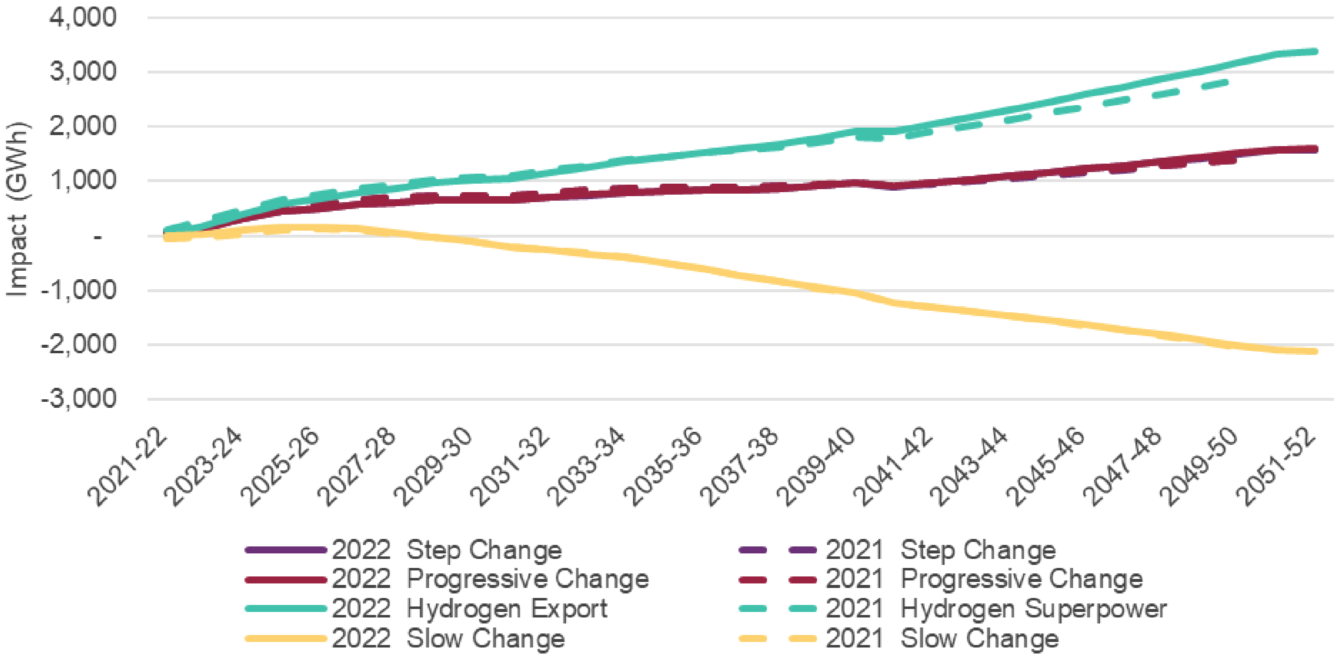
The 2022 appliance uptake forecast rebased the 2021 appliance uptake forecast, setting 2022 as the base year. The 2022 rebase of the appliance uptake forecast has resulted in a small upward shift of the forecasts: by 2050,

[27] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf?la=en.

consumption from appliance usage is approximately 110 gigawatt hours (GWh) higher than in the 2021 *Step Change* forecast.

Figure 8 shows the appliance uptake trajectory for the residential sector (excluding fuel switching from gas to electric devices that is considered separately in electrification) in the 2022 scenarios. As was the case in the 2021 forecast, the dispersion across the scenarios is derived by applying a per capita Household Disposable Income (HDI) index to the scenarios, relative to the per capita HDI to the moderate economic scenario (also detailed in Appendix A5 of AEMO's *Electricity Demand Forecasting Methodology*). This index is unchanged since the 2021 IASR.

Figure 8 Appliance uptake – change in current usage, relative to base year (2022) consumption for the residential sector



Note: *Step Change* and *Progressive Change* are following the same appliance uptake projection.

2.2.8 Electricity price indices

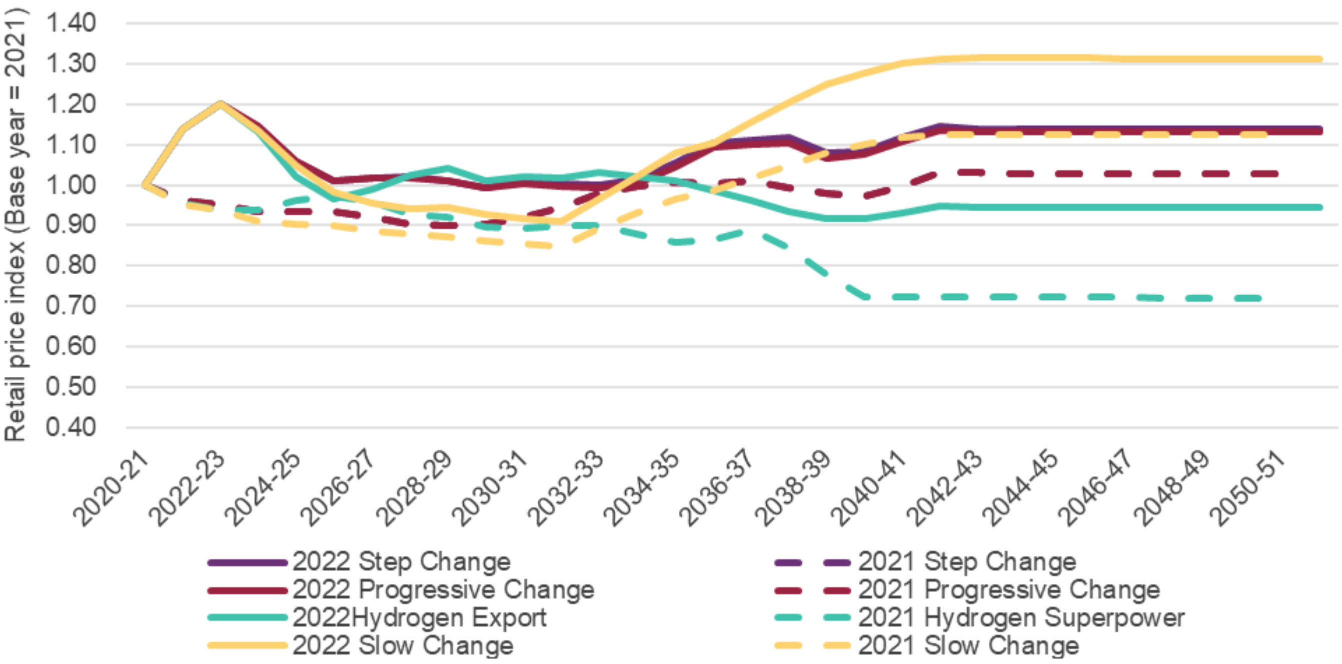
Input vintage	Updated in May 2022
Source	• Australian Energy Market Commission (AEMC) annual *Residential Electricity Price Trends* report, 2021 forecasts, at https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2021 • AER's Default market offer prices 2022–23: Final determination, at https://www.aer.gov.au/system/files/AER%20-%20Default%20Market%20Offer-%20Price%20determination%202022-23%20-%20Final%20Determination%20-%2026%20May%202022.pdf. • Victorian Default Offer 2022-23: Final Decision, at https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/victorian-default-offer/victorian-default-offer-price-review-2022-23#toc-victorian-default-offer-prices-to-apply-from-1-july-2022-to-30-june-2023-. • AEMO internal GSOO wholesale price forecasts • Transmission costs from the Draft 2022 ISP's optimal development path • ASX Energy Electricity Futures
Updates since Draft IASR	Retail price forecasts have been updated with the components from the latest AEMC 2021 report, a blend of ASX futures with 2022 GSOO wholesale price forecasts and transmission costs associated with the Draft 2022 ISP.

Electricity prices are assumed to influence consumption through short-term behavioural changes (such as how electricity devices are used or energy consumption is managed), and longer-term structural changes (such as decisions to invest in DER).

Figure 9 shows the retail price index assumed in 2022 for the *Step Change*, *Progressive Change*, *Slow Change*, and *Hydrogen Export* scenarios.

A sharp jump in wholesale prices has been observed across the NEM during the first half of 2022, driven by a combination of coal plant outages, rising fuel costs and high demand. AEMO captured this spike in an updated forecast by blending the wholesale price forecasts, as derived for the 2022 GSOO, with recent ASX Energy electricity futures data[28] to provide a sharp, short-term uplift in the prices across all scenarios.

Figure 9 Residential retail price index, NEM (connections weighted)



* Price weighted by the number of households per region.

The retail price forecasts otherwise are formed from bottom-up projections of the various components of retail prices.

0 shows the high-level mapping of the various price components used, and their incorporation into the 2022 scenarios. Components were mapped based on the relationship between the 2022 scenarios and the relevant settings of the 2022 GSOO and Draft 2022 ISP scenarios.

[28] Extracted from ASX Energy Datacentre on 3 June 2022

Table 6 High-level mapping of price input settings for proposed scenarios

Scenario	*Slow Change*	*Progressive Change*	*Step Change*	*Hydrogen Export*
Wholesale component	ASX Futures and 2022 GSOO blend to FY2025, then 2022 GSOO *Slow Change*	ASX Futures and 2022 GSOO blend to FY2025, then 2022 GSOO *Net Zero*	ASX Futures and 2022 GSOO blend to FY2025, then 2022 GSOO *Sustainable Growth*	ASX Futures and 2022 GSOO blend to FY2025, then 2022 GSOO *Hydrogen Superpower*
Transmission costs	AEMC (2021) to FYE 2024 Draft ISP (2022) *Slow Change*	AEMC (2021) to FYE 2024 Draft ISP (2022) *Progressive Change*	AEMC (2021) to FYE 2024 Draft ISP (2022) *Step Change*	AEMC (2021) to FYE 2024 Draft ISP (2022) *Hydrogen Superpower*
Distribution costs	AEMC (2021) to FYE2024 then constant	AEMC (2021) to FYE2024 then constant	AEMC (2021) to FYE2024 then constant	AEMC (2021) to FYE2024 then constant
Environmental costs	AEMC (2021) to FYE2024 then decline to zero by FYE2030	AEMC (2021) to FYE2024 then decline to zero by FYE2030	AEMC (2021) to FYE2024 then decline to zero by FYE2030	AEMC (2021) to FYE2024 then decline to zero by FYE2030
Retail component	AEMC (2021) derived residual in FYE22, DMO/VDO derived in FYE23 then constant	AEMC (2021) derived residual in FYE22, DMO/VDO derived in FYE23 then constant	AEMC (2021) derived residual in FYE22, DMO/VDO derived in FYE23 then constant	AEMC (2021) derived residual in FYE22, DMO/VDO derived in FYE23 then constant

Consumption forecasts consider the price elasticity of demand; that is, the percentage change in demand for a given change in price. The underlying price elasticity of demand that is used to give effect to the price indices and influence the consumption forecasts is as per the 2021 IASR.

Table 7 below provides the price elasticities of demand adopted across the modelled scenarios, where negative values indicate a reduction in consumption resulting from a price increase.

Table 7 Price elasticities of demand for various appliances and sectors.

Scenario	*Slow Change*	*Progressive Change*	*Step Change*	*Hydrogen Export*
Residential: Baseload appliances	0	0	0	0
Residential: weather-sensitive appliances	-0.10	-0.10	-0.10	-0.10
Business: all load components	-0.15	-0.10	-0.10	-0.05

2.2.9 Demand side participation

Input vintage	**Updated** forecast in June 2022
Source	• Historical meter data analysis and information submitted to the DSP Information Portal in April 2022 • Information about policy driven programs
Updates since 2021 IASR	New South Wales Peak Demand Reduction Scheme is included in all scenarios as now considered formally committed[29]
Update process	Forecast DSP will be updated based on information submitted to the DSP Information Portal in April 2023 and historical meter data analysis

AEMO's forecast approach considers DSP explicitly in its market modelling, meaning that demand forecasts reflect what demand would be in the absence of DSP to avoid double counting. The forecast for DSP in the upcoming year is produced following AEMO's Demand Side Participation Forecast Methodology[30] .

[29] See https://www.energy.nsw.gov.au/government-and-regulation/energy-security-safeguard/peak-demand-reduction-scheme.

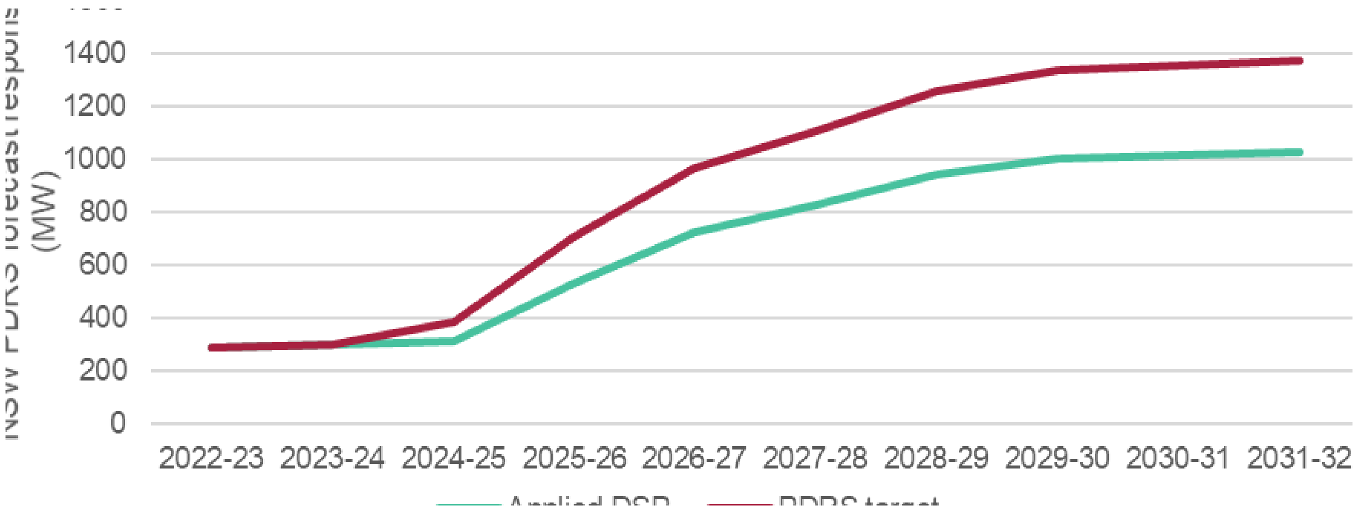
[30] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

The reliability response estimate is the key input to the ESOO process, showing the maximum estimated demand reduction possible to avoid USE during supply shortfalls. For all regions except New South Wales, the static DSP forecast for the upcoming year have been used for the 10-year horizon of the ESOO for all scenarios, as no other data source is available to provide a reference for future trends in DSP growth or decline.

The NSW Peak Demand Reduction Scheme (PDRS) is now a committed scheme and creates a financial incentive to reduce electricity consumption during peak times in New South Wales[31]. The scheme is included in all scenarios, starting in 2022-23 with the target growing to 10% of forecast peak demand by 2029-30, then staying flat. The scheme will, in its current design, only provide additional DSP during summer. The impact on DSP considers that 25% of the PDRS target will be delivered through energy efficiency and battery storage initiatives, which are accounted for separately in AEMO's forecast components. Accordingly, the growth in DSP is scaled down to match.

Figure 10 shows the PDRS targets in MW values as well as the adjusted targets expected to be achieved through DSP (removing the assumed contribution from energy efficiency and battery storage). For New South Wales's summer, the forecasts in Figure 10 are used in the 2022 ESOO.

Figure 10 PDRS target and DSP applied in ESOO forecasts, Summer, 2022-23 to 2031-32, all scenarios



For longer-term planning studies, such as the ISP, AEMO uses different scenario-specific projections out to 2052 to account for DSP resources that may be developed consistent with the defined scenario settings. The DSP projections by scenario out to 2052 will be published for consultation in AEMO's draft 2023 Inputs and Assumption Workbook in December 2022.

2.3 Existing generators and transmission

AEMO uses a range of data to describe the existing generators in its models. Some of this data is updated through established processes and documented methodologies as outlined in 0 below.

[31] This is for the New South Wales state only. The NEM region of New South Wales includes ACT as well, so adjustments have been made to ensure the target reflects the New South Wales state demand only.

Table 8 Status and update process for key inputs and assumptions for existing generation and transmission

Input	Status	Updates since 2021 IASR
Generation Information data	Updated	• Updated based on NEM Generation Information July 2022 survey and is published on AEMO's Generation Information website [A]. • This data is collected and published in accordance with the Generation Information Guidelines [B].
Marginal loss factors (MLFs), inter-regional loss flow equations and loss proportion factors	Updated	• Initial MLFs, loss equations and proportioning factors are based on the Marginal Loss Factors for the 2022-23 Financial Year report [C]. Loss equations and proportioning factors are varied based on flow path augmentations, as outlined in the ISP Methodology [D].
Scheduled generator forced outage rates	Updated	• The outage data was updated based on historical and forward-looking forced outage rates provided by registered participants in accordance with AEMO's Standing Information Request [E]. The data was collected in April 2022 and thus accounts for generator performance over the 2021-22 summer. • Based on the methodology outlined in the ESOO and Reliability Forecast Methodology [F] AEMO calculated new generator forced outage rates for all scheduled generators. • The forced outage rates were presented for FRG Consultation in June 2022.
Forced outages affecting inter-regional power transfers	Updated	• AEMO updated its approach to modelling forced outage rates for transmission elements affecting inter-regional power transfers as result of the consultation of the 2020 Forecast Improvement Plan [G]. • AEMO engaged with stakeholders through FRG consultation on the approach scheduled for January 2022, while the resulting forced outage rates were presented for FRG Consultation in June 2022.
Transmission network modelling	Updated	• Updates to transmission project timing and constraint equations based on latest available information.
Technology costs	Updated	• Updated based on GenCost 2021-22, the final version of which was finalised in July 2022.
Technical and other cost parameters	Updated	• Updated based on Aurecon 2021-22 AEMO costs and technical parameter review.

A. At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.
B. At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/final-generation-information-guidelines.pdf.
C. At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.
D. At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf.
E. At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/standing-information-requests.
F. At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/esoo-and-reliability-forecast-methodology-document.pdf.
G. At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/forecast-improvement-plan/forecast-improvement-plan-2020.pdf.

2.3.1 Generator forced outage rates

For the 2022 ESOO, AEMO collected information from all generators on the timing, duration, and severity of unplanned forced outages, via its annual survey process. This includes information on historical outages, and (for selected participants) outage projections across the 10-year forecast period. This data was used to calculate the probability of full and partial forced outages in accordance with the *ESOO and Reliability Forecasting Methodology*. For small peaking plants and hydro generator technology types, technology aggregates are applied to individual stations to smooth the impact of outlying years. Where participants have provided outage rate projections, AEMO has adopted these in agreement with station owners/operators.

Long duration unplanned outages

As described in the *ESOO and Reliability Forecast Methodology*, AEMO models outages with a duration longer than five months (long duration outages) from historical outage data from 2010-11 to 2021-22, prior to calculation of the expected Forced Outage Rate. For the 2022 ESOO, AEMO used an extended historical period of all available data (12 years) to determine the (unplanned) long duration outage rates for each region and technology class.

The long duration outages used in 2022 ESOO modelling, and in other reliability assessments such as Medium Term Projected Assessment of System Adequacy (MT PASA) and Energy Adequacy Assessment Projection (EAAP), are shown in Table 9.

Table 9 Existing generators – long duration outages

Fuel type/technology	Long duration outage rate (%)	Mean time to repair (hours)
Brown coal	0.54%	5,290
Black coal NSW	0.70%	5,568
Black coal QLD	0.68%	5,423
All coal average	0.66%	5,466
OCGT	0.83%	6,411

OCGT: Open cycle gas turbine.

Forced outage rate trajectories (excluding long duration outages)

The first year forced outage rates assumed in the 2022 ESOO are based on participant-provided information and projections for each technology, as shown in Table 10. Relative to the values used in the 2021 ESOO, the rates for 2022-23 have increased.

Table 10 Forced outage assumptions (excluding long duration outages) for 2022-23 year

	Full forced outage rate – 2022 ESOO (%)	Full forced outage rate – 2021 ESOO (%)	Change since 2021 ESOO (%)	Partial forced outage rate (%)	Partial derating (% of capacity)	Mean time to repair – Full outage (Hours)	Mean time to repair – Partial outage (Hours)
Brown coal	7.49	6.14	+1.35	6.68	19.6	89	10
Black coal QLD	4.97	4.09	+0.88	12.08	23.19	150	48
Black coal NSW	8.11	6.49	+1.62	37.23	17.17	169	48
OCGT	4.63	3.74	+0.89	1.95	4.37	12	13
Small peaking plant*	7.44	6.82	+0.62	0.45	34.95	74	38
Hydro	2.70	2.62	+0.08	0.07	31.46	52	80
CCGT + gas-fired steam turbines	3.55	2.33	+1.22	2.28	9.94	54	18

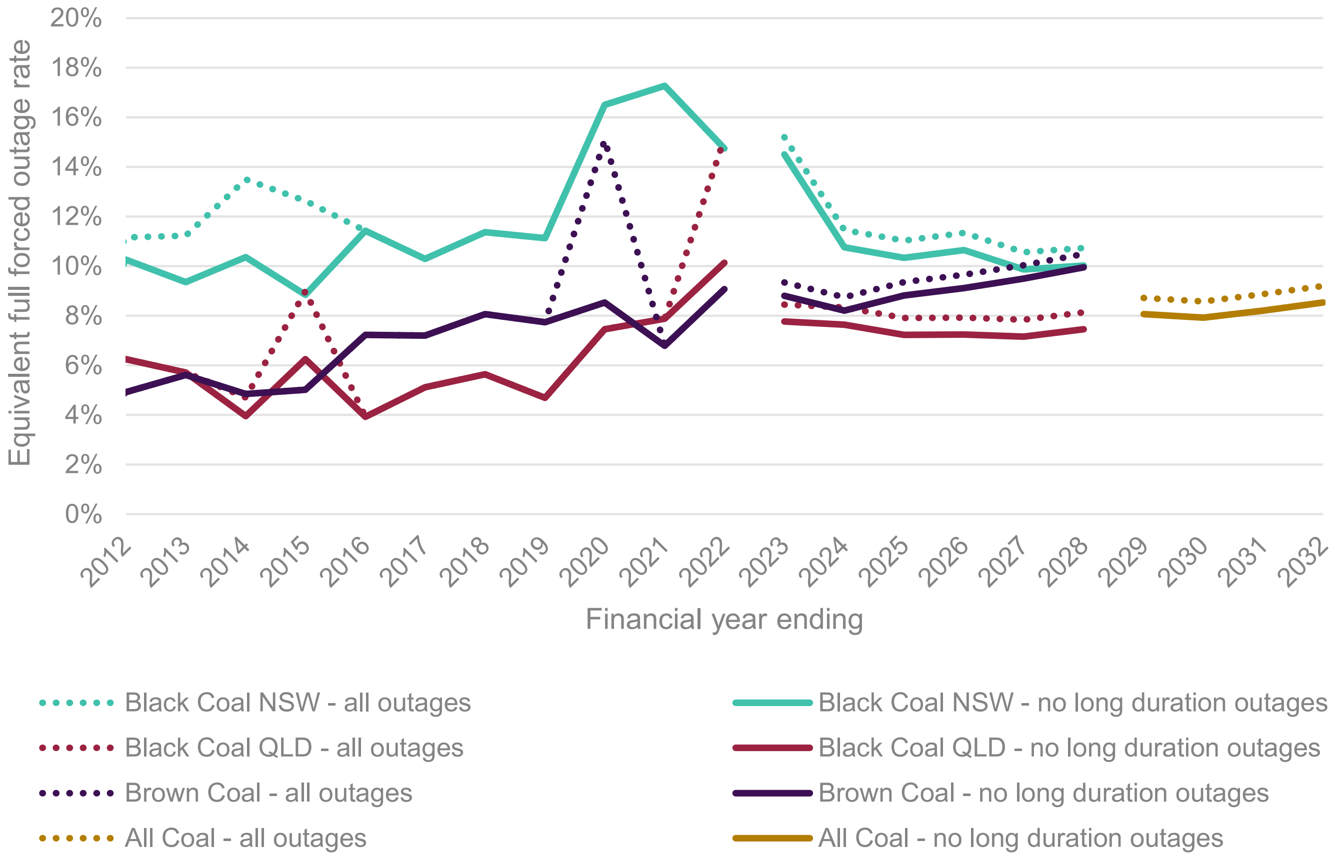
*Small peaking plants are generally classified as those less than 150 MW in capacity, or with a very low and erratic utilisation (such as Colongra and Bell Bay/Tamar peaking plant)
CCGT: Closed cycle gas turbine.

The 10-year projections for the equivalent full forced outage rate[32] of all technology aggregates are shown in Figure 11 and Figure 12, with and without the effect of long duration outages. The annual equivalent forced outage rate is affected by changes to assumed reliability and retirements of generators over the horizon. To protect the confidentiality of the individual station-level information used, forced outage trajectories are provided for the first 10 years of the horizon for technology aggregates only. Due to the small number of coal plant in later years, all regions have been further aggregated to an 'all coal' value to protection confidentiality.

[32] Where effective full forced outage rate = Full forced outage + partial outage rate x average partial derating.

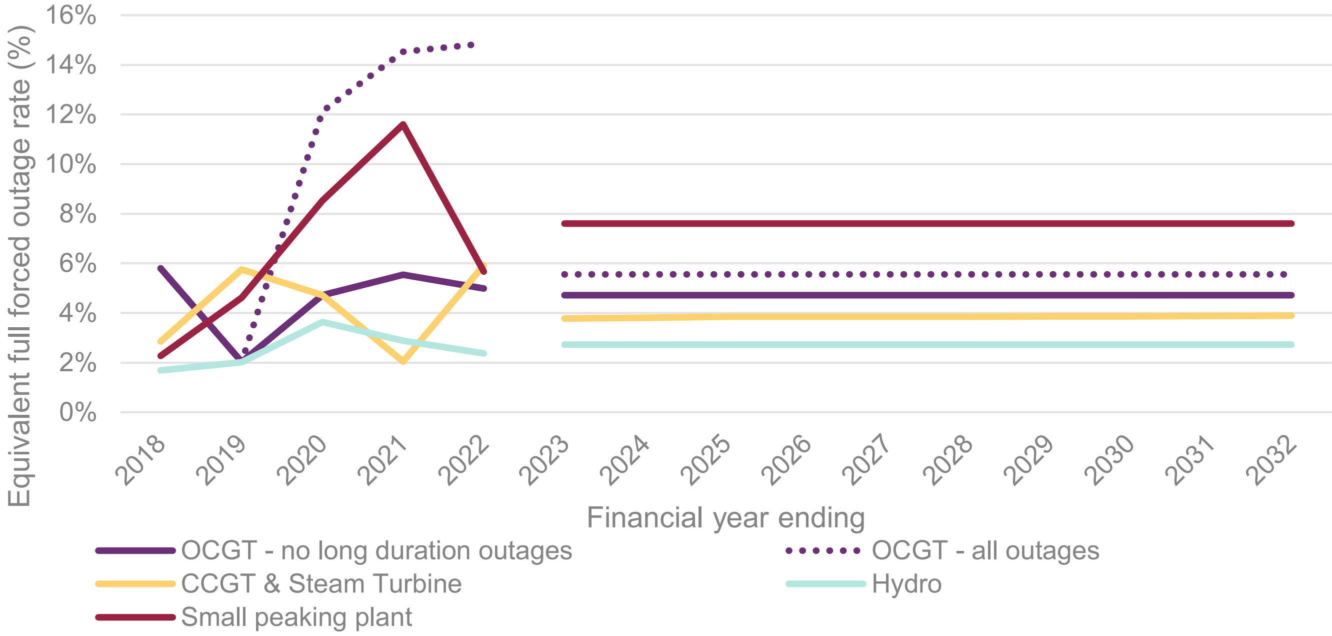
More information on treatment of outage rates across AEMO's modelling is provided in the ISP Methodology[33].

Figure 11 Equivalent full forced outage rate projections for coal-fired generation technologies



[33] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology.

Figure 12 Equivalent full forced outage rate projections for other generation technologies



Inter-regional transmission line unplanned outage rates

Similar to generators, unplanned outage rates of inter-regional transmission elements are critical inputs for AEMO's reliability assessments. Information is collected on the timing, duration, and severity of the transmission outages to inform transmission forced outage rate forecasts. Table 11 shows the rates and method used in the 2022 ESOO. The selection of inter-regional flow paths has varied from the 2021 ESOO consistent with the updated *ESOO and Reliability Forecast Methodology*.

Table 11 Inter-regional transmission flow path outage rates

Flow path	2022 FOR (%)	2022 Mean time to repair (hours)	Outage rate method
Liddell – Muswellbrook – Tamworth – Armidale – Dumaresq – Bulli Creek (QNI)	1.5	5	Annual static
Murraylink	0.1	8.9	Annual static
Mortlake-Heywood-South East (V-SA))	0.3	20.1	Annual static
Basslink	6.4	244	Annual static

2.3.2 Technology build costs

Capital cost trajectories

AEMO's generator capital cost trajectories are informed by the *GenCost* publication series, an annual publication of electricity generation technology cost projections conducted jointly through a partnership between CSIRO and AEMO. To support this forecast, Aurecon have provided estimates of the current capital cost of each generation technology (and supporting technical information). The GenCost projections use CSIRO's GALLM model, which produces capital cost forecasts that are a function of global and local technology deployment.

Since the 2021 IASR, the GenCost scenarios have evolved to better reflect the uncertainty in the speed of global emissions reduction, which improves the alignment with AEMO's scenarios.

The build cost projections are given for three GenCost scenarios ("Global NZE by 2050", "Global NZE post 2050" and "Current policies"). These scenarios are described in greater detail in CSIRO's GenCost report[34]. AEMO maps the 2022 scenarios to the GenCost scenarios, as shown in Table 12. The scenario mapping of GenCost scenario to 2022 scenario reflects what AEMO considers the best fit to the narratives of AEMO's scenario collection.

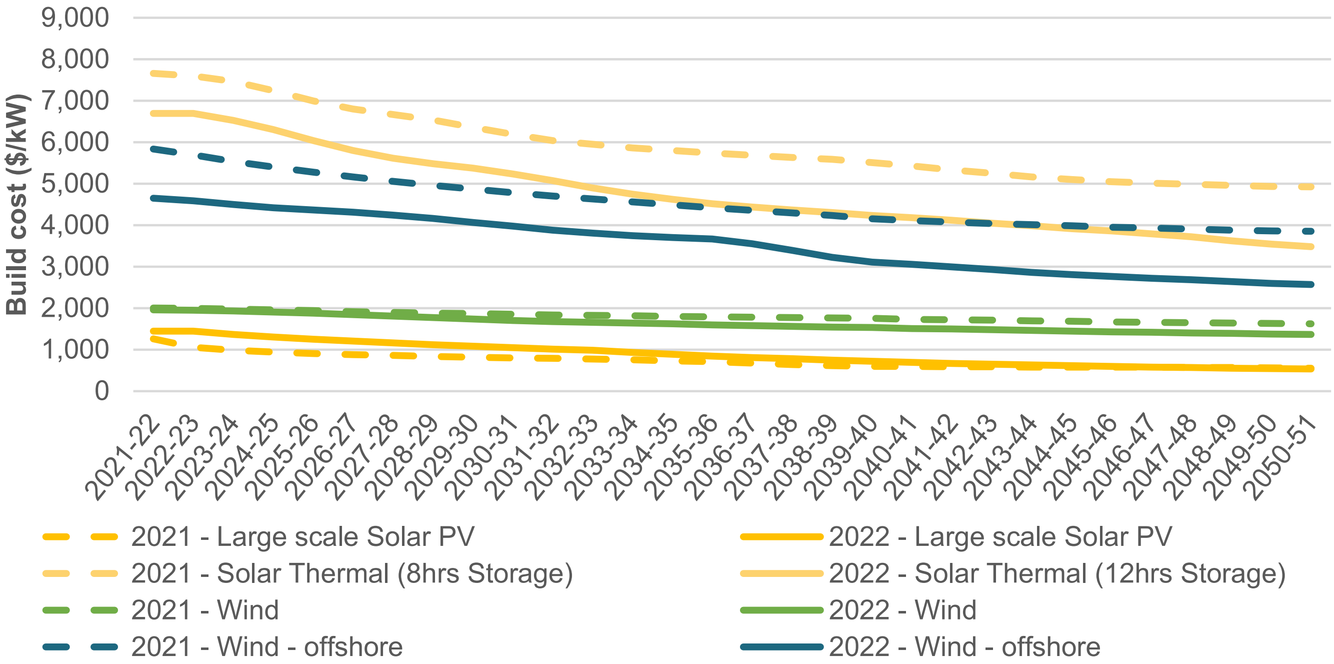
Table 12 Mapping AEMO scenario themes to the GenCost scenarios

AEMO scenario	GenCost scenario	Explanation
Slow Change	Current Policies	Consistent with current commitments to the Paris Agreement, leading to the lowest global emissions reduction ambition and a 2.6 degree warming future.
Progressive Change	Current Policies*	
Step Change	GenCost Global NZE post 2050	Consistent with global action to limit temperature rises to less than 2 degrees, and with industrialised countries targeting net zero emissions by 2050.
Hydrogen Export	GenCost Global NZE by 2050**	The most ambitious global emissions reduction scenario, consistent with limiting temperature rises to less than 1.5 degrees, as well as a strong focus on electrification and hydrogen-based developments.

* While *Progressive Change* does increase its emissions reduction ambition, achieving net zero emissions by 2050, the scenario also delays significant action to align with a higher warming future. As such, it more aligns with Current Policies' 2.6 degree warming future.
**The *Hydrogen Export* scenario assumes more accelerated capital cost reductions for large-scale Solar PV compared to the Global NZE by 2050 GenCost scenario, as a key enabler of hydrogen expansion for export.

Figure 13, Figure 14 and Figure 15 present a comparison of GenCost 2021's High VRE against GenCost 2022's Global NZE post 2050 build cost projections for selected technologies (if constructed in Melbourne and excluding connection costs). Cost projections for each technology and scenario are available in the *Forecasting Assumptions Update Workbook*.

Figure 13 2022's Global NZE post 2050 vs 2021's High VRE: build cost trajectories forecast, for wind and solar



[34] At https://www.csiro.au/-/media/News-releases/2022/GenCost-2022/GenCost2021-22Final_20220708.pdf.

Figure 14 2022's Global NZE post 2050 vs 2021's High VRE: build cost trajectories forecast, for gas

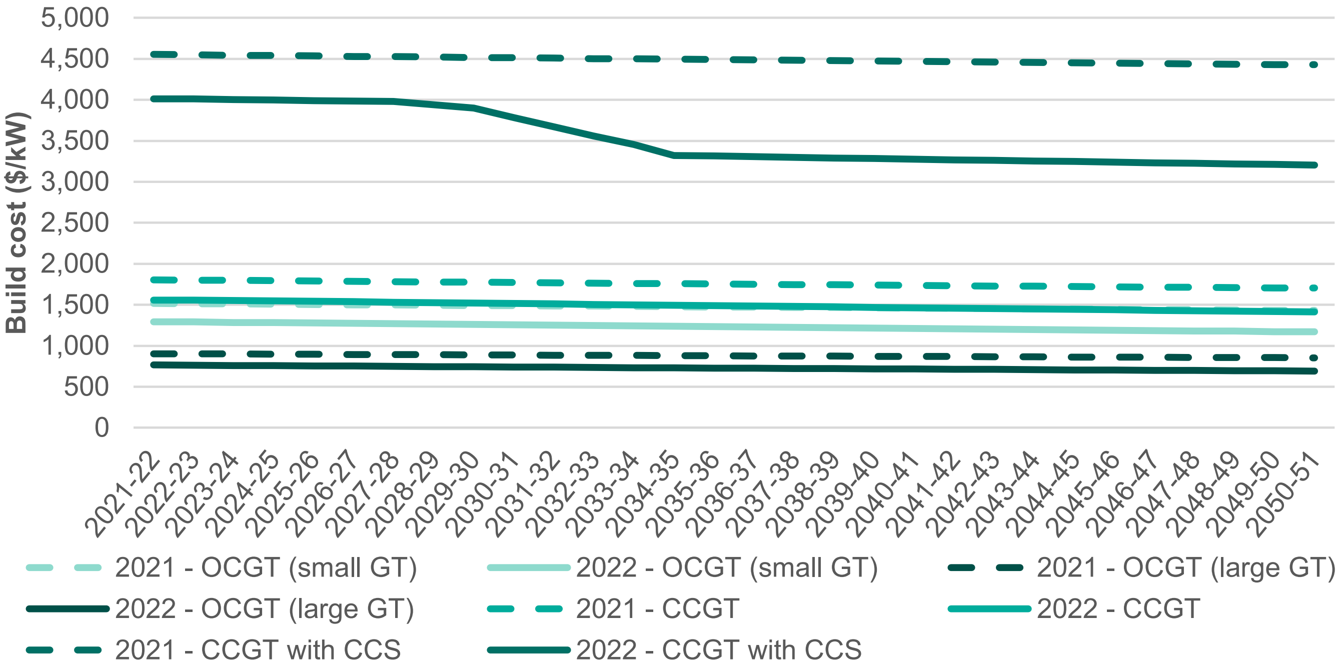
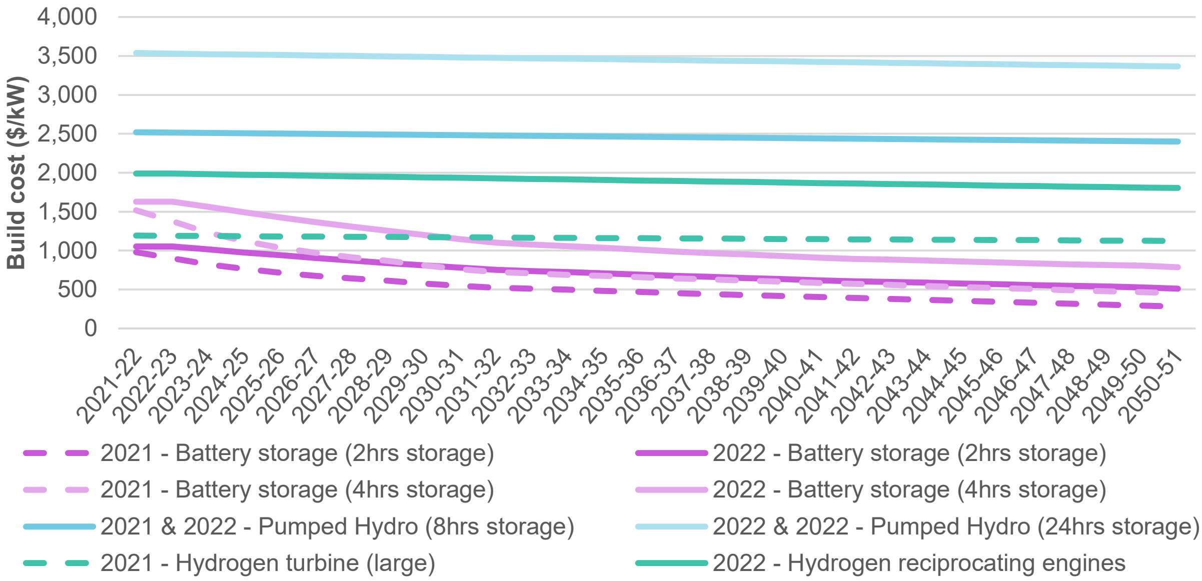


Figure 15 2022's Global NZE post 2050 vs 2021's High VRE: build cost trajectories forecast for selected storage, hydrogen



When comparing the capital costs between AEMO's Updated Assumptions Book and CSIRO's GenCost trajectories, there are a number of differences that need to be noted:

- GenCost assumes that wind capacity factors improve over time due to technological advancements. In AEMO's modelling, the quality of resource is unchanged over the forecasting horizon, so to account for these improvements the capital costs are reduced by the relative improvement in capacity factor.
- At times, the presentation of real dollars between the two publication is not aligned. For this *Forecasting Assumptions Update* both documents present costs in real June 2021 dollars, so no adjustment is required.

- GenCost's projections are presented as the year 2021 (for example). In AEMO's Updated Assumptions Workbook this is the cost used for the 2021-22 financial year.
- When comparing GenCost's capital costs in $/kW with Aurecon, note that Aurecon does not include the cost of land in its presentation of $/kW capital costs, whereas this is included by GenCost, and therefore by AEMO.

The costs provided in the 2021-22 GenCost publication do not fully capture some of the recent cost pressures that are affecting a range of infrastructure projects. Understanding the impact of recent conditions and how to project forward in the near-term will be a key focus of the 2022-23 GenCost process.

Technology cost breakdowns

To calculate the capital costs of technologies developed in different locations, the locational cost factors provide a multiplicative scalar to the respective generation and storage development component costs (equipment, fuel connection, land and development, and installation). These scalars are derived from regional development cost weightings by cost component, and technology cost component breakdowns, which are presented in Table 13. This *Forecasting Assumptions Update* captures updated technology cost component breakdowns, informed by updated data from the 2021-22 GenCost. Few technologies have seen changes in ratios, and apart from hydrogen reciprocating engines[35] have done so marginally. Otherwise, wind sees the most significant change in the below table compared to the 2021 IASR, with a three-percentage point reduction in the cost of land and development, seeing instead an increase in equipment and to a lesser extent installation costs.

The Updated Assumptions Book provides additional details of these cost factors, including the resulting regional technology cost adjustment factors.

Table 13 Technology cost breakdown ratios

Technology	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs
Black coal (advanced ultra supercritical PC)	32%	3%	16%	48%
Black coal (advanced ultra supercritical PC) with CCS	33%	2%	16%	49%
OCGT (small GT)	60%	6%	8%	26%
OCGT (large GT)	58%	10%	7%	25%
Hydrogen based reciprocating engines	55%	0%	8%	37%
CCGT	62%	3%	8%	27%
CCGT with CCS	63%	2%	8%	27%
Biomass	33%	0%	17%	50%
Battery storage (1hr storage)	75%	0%	10%	15%
Battery storage (2hrs storage)	77%	0%	7%	16%
Battery storage (4hrs storage)	79%	0%	5%	16%
Battery storage (8hrs storage)	81%	0%	3%	17%
Large-scale solar PV	57%	0%	6%	38%
Solar thermal (12hrs Storage)	75%	0%	0%	25%

[35] Fuel connection costs have gone down to 0% for hydrogen reciprocating engines, as they are excluded by Aurecon – hydrogen is assumed to be supplied via electrolysers/ blending. Ratios were previously assumed to be the same as OCGT (large GT) due to lack of data.

Technology	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs
Wind	68%	0%	3%	29%
Wind – offshore	69%	0%	2%	29%

CCS: Carbon capture and storage.

2.3.3 Technical and other cost parameters (new entrants)

Technical and other cost parameters for new entrant generation and storage technologies include:

- Unit size and auxiliary load.
- Seasonal ratings.
- Heat rate.
- Scope 1 Emissions factors.
- Minimum stable load.
- Fixed and variable operating and maintenance costs.
- Maintenance rates and reliability settings.
- Lead time, economic life, and technical life.
- Storage parameters (including cyclic efficiency and maximum and minimum state of charge).

These parameters for new entrant technologies are updated as part of the annual GenCost scope of work to reflect the current trends and estimates of future cost and performance data of new technologies. These are published in the Updated Assumptions Book and in the supporting material from Aurecon.

2.3.4 Storage modelling – batteries

Large-scale battery expansion candidates are modelled with fixed power to energy storage ratios, but with flexibility to charge and discharge to achieve the optimal outcome for the system within the fixed power to energy storage ratio limit.

Assumptions for battery storages of 1-hour, 2-hour, 4-hour, and 8-hour duration depths are based on data provided by Aurecon in its latest report. Battery storage degradation, which Aurecon indicates is 1.8% annually, is not able to be modelled explicitly due to computational complexity (particularly in capacity outlook models). While AEMO does not model this factor explicitly, AEMO reduces the storage capacity of all battery storage by 16% which is an estimate of the average storage capacity over the battery life after taking into account this degradation and estimated operating levels.

Aurecon's specification of batteries is for the usable storage capacity. AEMO's technology cost assumptions sourced from GenCost therefore consider the usable storage capacity in defining project costs, and its modelling assumes a minimum and maximum state of charge of 0% and 100% respectively.

2.3.5 Other technology costs

The CSIRO GenCost 2021-22 report contains estimates for the forecast costs for electrolysers, including proton exchange membrane (PEM) and alkaline technologies. Hydrogen electrolyser development is presently being supported by trials both globally and in Australia. This may lead to cost reductions through time as electrolyser manufacturing scales up.

Aurecon's input to the GenCost process also provides estimated capital cost, as well as other operating assumptions, for a range of other technologies. Although these are not directly used in AEMO's models, they may inform other processes, and they are also included to provide information to stakeholders. These technologies include, for example, biogas digesters, biodiesel production facilities, hydrogen liquefaction and storage facilities, demineralisation and desalination plants, and ammonia production facilities. This data is available in Aurecon's 2021-2022 AEMO costs and technical parameters review.

2.4 Fuel price assumptions

Gas prices

Input vintage	**Updated** December 2021
Source	Lewis Grey Advisory
Updates since 2021 IASR	Updated gas prices from Lewis Grey Advisory consultancy, consulted upon in November 2021 FRG

AEMO sourced natural gas price forecasts from consultant Lewis Grey Advisory (LGA). These gas prices were updated in December 2021, for the 2022 GSOO report. Gas price forecasts are derived from a game theory model that simulates competitive pricing outcomes suitable to reflect contract pricing[36]. Gas production costs, reserves, infrastructure, and pipeline tariffs are fundamental inputs into this model that also considers international natural gas prices, oil prices, and measures of the domestic economy. The methodology was presented at the FRG in November 2021[37], and the assumptions are detailed in the LGA report[38].

Several improvements to methodology and inputs (listed in Table 14) have also been implemented considering stakeholder feedback from the previous LGA forecast from 2020. Specifically, projected pipeline transmission costs now consider the influence of falling gas demand, and forecasts of gas prices for gas-fired generation now consider the regional load factors of these generators and have been benchmarked against the July 2021 Gas Inquiry interim report, published by the Australian Competition and Consumer Commission[39].

[36] The price projections do not attempt to model the full variance of the spot market. The spot market can sometimes experience pricing at very high levels when there is little uncontracted gas available and sometimes at very low levels, even below breakeven, when there is a surplus of uncontracted gas available.

[37] AEMO. FRG minutes and meeting packs, at https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

[38] At https://aemo.com.au/consultations/current-and-closed-consultations/2022-consultation-on-forecasting-assumptions-update.

[39] ACCC, Gas inquiry July 2021 interim report, at https://www.accc.gov.au/publications/serial-publications/gas-inquiry-2017-2025/gas-inquiry-july-2021-interim-report.

Table 14 Improvements applied to gas price forecasts

Changes from July 2021	Variable description	Method applied
Gas transmission costs	Transmission costs to the relevant gas transmission node is the cost of shipping gas from one node to another.	Estimated transmission costs are now indexed to the inverse of estimated gas demand to reflect the fixed cost nature of gas infrastructure.
Regional load factors applied in gas-powered generation gas prices	A generator's load factor is a measure of the utilisation rate, or efficiency of electrical energy usage. A gas-fired generator's load factor varies across each year between peak and non-peak periods.	Wholesale prices for gas-fired generators is adjusted by applying the load factor of each gas-fired power generation region, this is estimated by usage during winter peak periods, as it is forecast in the 2021 GSOO.
Forecasts benchmarked against ACCC most recent published prices	LGA's model now benchmarks its gas pricing model against contract prices reported by the ACCC in the Gas Inquiry 2017-2025 Interim Report, July 2021.	Benchmarking is done by replicating Eastern Australia gas market conditions before these contracts were entered. LGA tests this by applying its model without any prior domestic contracts in 2021 (but assuming export contracts were in place) and with contract durations of one year.

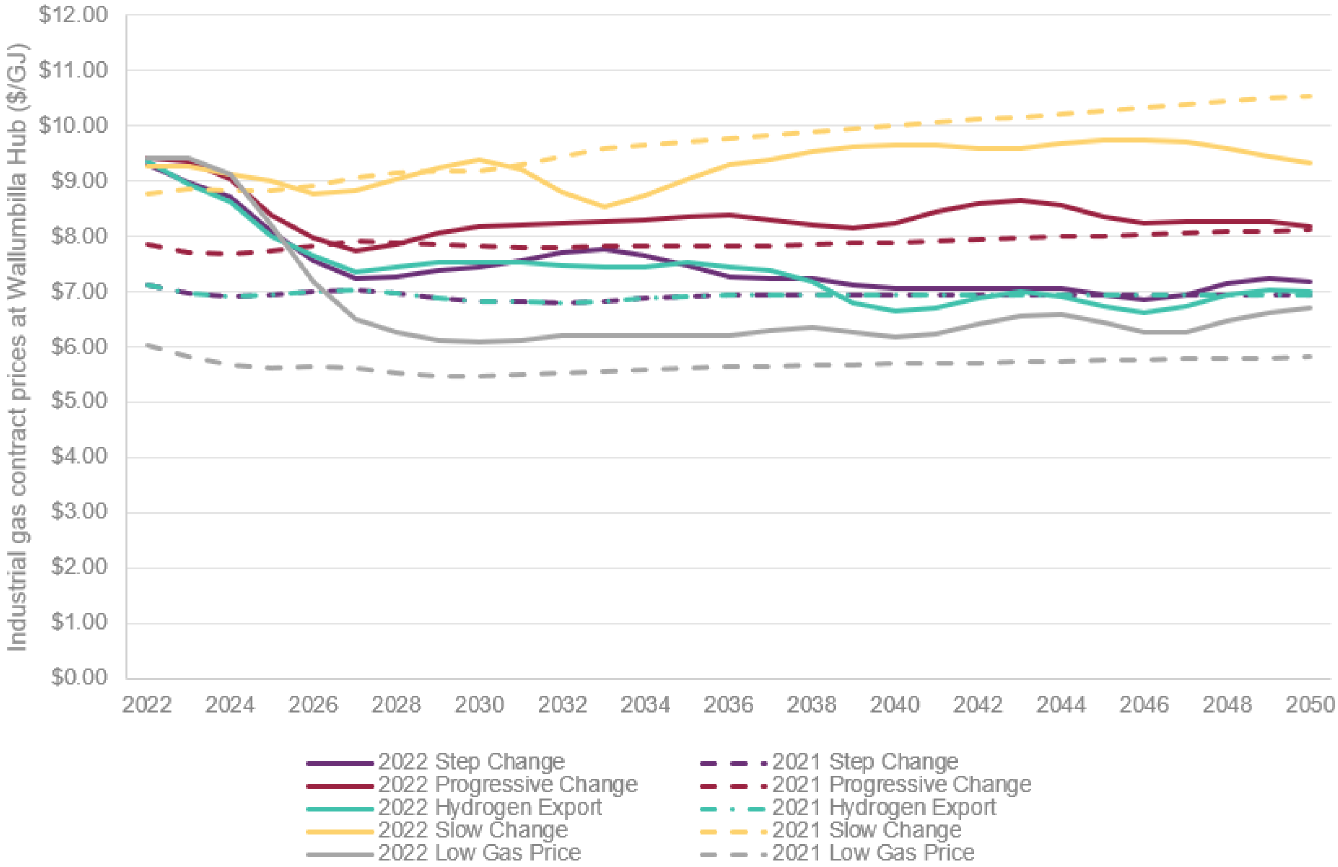
Six gas price forecasts were provided, based on assumptions about gas reserves, international gas pricing, Australian infrastructure, cost of producing gas from existing and upcoming petroleum fields, and the local level of competition. For all trajectories, no explicit reservation policy was considered, and it was assumed that the Port Kembla Gas Terminal would have the capability to import LNG into Australia from winter 2023 onwards. This was consistent with the commitment status of the project in the 2021 GSOO, but during the subsequent 2022 GSOO work, the status of the project was downgraded to anticipated and with a start date in time for winter 2024.

In a *Low Gas Price* sensitivity, LGA assumed new gas fields will be developed for the Gunnedah, North Bowen, Galilee and Beetaloo gas basins with additional pipeline infrastructure to connect these gas basins to the Eastern Australia gas market from 2023.

Gas prices for gas-fired generators are provided in the Updated Assumptions Book. The costs include regional pricing, considering the supply options and the relevant cost of pipeline transmission. They also apply a further adjustment based on pipeline transmission to the actual generation plant, and influence of contracts. These factors, and the improvements mentioned previously, drive the difference in outcomes to the previous 2021 IASR forecasts.

Figure 16 presents a gas price comparison for industrial consumer prices, measured at Wallumbilla, comparing the updated forecast with the previous forecast in the 2021 IASR. Other consumer types, such as gas generation users, are in the Updated Assumptions Book.

Figure 16 Average industrial gas price forecast at Wallumbilla



2.5 Transmission network modelling

Input vintage	**Updated** since the 2021 IASR
Source	• 2022 ISP • Transmission Network Service Providers
Updates since 2021 IASR	Described below, and in the 2022 ESOO

Most of the transmission network modelling assumptions applied in the 2022 ESOO are consistent with those canvassed through the 2021 IASR and 2022 ISP. The following changes were made to reflect the most up to date information available:

- Updates to the committed, anticipated and ISP actionable transmission network projects, including updated project scopes, timing and status consistent with the 2022 ISP and the advice from transmission network service providers responsible for the delivery of ISP projects. Details are provided in the 2022 ESOO report.
- Updates to proportioning factors for inter-regional losses for existing flow paths, to align with AEMO's marginal loss factors publication for 2022-23. Details are provided in the 'Proportioning factors' tab of the Updated Assumptions Book.
- Updates to transmission constraint equations to reflect the latest constraints used in the NEM Dispatch Engine (NEMDE), and subsequent updates to forecast those constraints for the ESOO time horizon. The 2022 ESOO model provides the constraint equations used for the 2022 ESOO.