2021 IASR Consultation Summary Report

July 2021

Consultation Summary Report

Important notice

PURPOSE

AEMO publishes this 2021 IASR Consultation Summary Report pursuant to National Electricity Rules (NER) 5.22.8. This report includes key information and context for the inputs and assumptions used in AEMO's Forecasting and Planning publications for the National Electricity Market (NEM).

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VERSION CONTROL

Version	Release date	Changes
1	30/7/2021	

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1. Introduction

AEMO delivers a range of forecasting and planning publications for the National Electricity Market (NEM), including the NEM Electricity Statement of Opportunities (ESOO), the Gas Statement of Opportunities (GSOO), and the Integrated System Plan (ISP). AEMO uses a common set of inputs, assumptions and scenarios in developing these publications.

Every year, AEMO works with stakeholders to update the inputs and assumptions that will be used in AEMO's development of a number of major planning and forecasting publications for the year ahead. The 2021 Inputs, Assumptions and Scenarios Report (IASR), to which this document is an accompaniment, outlines the scenarios, modelling inputs and assumptions that will be used in AEMO's activities over the coming year, including the development of the 2022 ISP.

This document outlines how AEMO has taken stakeholder feedback into account in developing the 2021 IASR. The document is divided into two parts. Sections 1, 2, 3 and 4 summarise the consultation process on the IASR, and highlight the key changes that have been made to the Draft IASR. Section 5 provides AEMO's responses to material issues raised by stakeholder in their submissions.

1.1 Consultation on the development of the 2021 IASR

Consultation with consumers, market participants and all other stakeholders is a foundational element of all AEMO's activities. Throughout the development of the 2021 IASR, AEMO has sought to offer all interested stakeholders the opportunity to understand the process and contribute to the final outcome.

The consultation process has contained the following major elements:

- Public workshops and webinars on a range of topics, including the development of scenarios.
- Consultation on Draft IASR.
- Consultation on revised draft scenarios.
- Additional supplementary consultations on specific inputs and assumptions.
- Direct discussions with stakeholders, including the ISP Consumer Panel.

Scenario development

The scenario development process began with AEMO surveying stakeholders for their views of five key dimensions and trends in the energy use, being:

- Decentralisation of the power system.
- Decarbonisation of the power system.
- Relative cost competitiveness of renewables and storage.
- Electrification of transport.

- Broader economic activity and population[1].

Around 100 responses were received. Based on responses, AEMO identified an initial set of seven scenarios (and risks), to form the basis of initial scenario workshops with stakeholders.

The first public scenario workshop was held on 14 October 2020. The workshop was attended by more than 80 attendees from 65 organisations. Participants workshopped the scenarios extensively, considering and defining specific scenario dimensions reflecting uncertainties that could materially impact the future development of the NEM, naming scenarios and developing accompanying narratives about both future worlds and the path from the current state to that future.

A second scenario development workshop was held on 22 October 2020. That event explained how input from stakeholders contributed to the initial scenario narratives, provided an initial opportunity for comment from stakeholders, and outlined the next steps in the scenario development process[2].

A third scenario development workshop was held on 11 November 2020, presenting stakeholders with an updated version of the draft scenario narratives. In that workshop, AEMO gathered further feedback from stakeholders about both the updated narratives and the scenario development process so far.

Consultation on Draft IASR

The Draft IASR and workbook were published on 11 December 2020, with submissions due on 1 February 2021. In total, 47 submissions were received. More information about key themes from submissions is provided in Section 2.2 of this report[3].

AEMO provided energy consumer advocates with the opportunity to provide verbal submissions to the consultation. AEMO did so in response to requests from advocates and in acknowledgement of their particularly limited resources to produce written submissions. Fourteen consumer groups attended this session, with seven providing specific verbal submissions. AEMO produced a written record of these comments which, once verified with speakers, was considered along with all other written submissions.

On 3 March 2021, AEMO held a webinar with stakeholders to discuss submissions to the Draft IASR. This session provided stakeholders with an overview of feedback received in submissions and outlined the continued engagement process for the final IASR.

Consultation on revised draft scenarios

One of the strongest themes in submissions to the Draft IASR was that AEMO's central scenario did not assume a high enough level of decarbonisation. In response to these submissions, AEMO developed a revised set of draft scenarios, which were explained to stakeholders at the public workshop on 3 March 2021. This commenced a period of further consultation, where stakeholders were invited to submit written submissions over a two-week period.

Additional supplementary consultations on specific inputs and assumptions

In response to submissions to the Draft IASR, AEMO undertook additional engagement on individual inputs and assumptions, including:

- **Transmission cost estimates**, as part of the development of the Transmission Cost Database and associated report. On 15 April 2021, AEMO held a public webinar at which stakeholders heard from, and

[1] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/scenario-narrative-development-webinar-presentation-slides.pdf?la=en&hash=BD6D531BE742C4CB01BE1AC89F973E92 Slide 9.

[2] The slides for the 22 October workshop and recording are available on the Opportunities for Engagement page: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement.

[3] All submissions are available at: https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios.

were able to question, AEMO's external consultants (GHD).[4] The Draft Transmission Cost Database and report were then released for written consultation on 28 May 2021, for four weeks.[5] A further workshop was held on 10 June 2021 to summarise feedback from submissions and provide a final opportunity for stakeholders to ask questions. Submissions to the *Draft 2021 Transmission Cost Report* are available on AEMO's website. AEMO's response to these submissions are included in this report.

- **Discount rates** to be used in undertaking ISP cost-benefit analyses, about which AEMO sought external advice in April-July 2021. AEMO engaged with the ISP Consumer Panel, Australian Energy Regulator (AER), transmission network service providers (TNSPs), and the Clean Energy Finance Corporation as a targeted consultation process.
- **Gas price assumptions,** and the use of a low gas price sensitivity in ISP modelling, were the subject of a webinar on 23 May 2021.[6] Stakeholders were able to engage with AEMO's external expert, Lewis Grey Advisory (LGA).
- **Refinement of interim inputs in the Draft IASR**, through regular Forecasting Reference Group (FRG) meetings, on forecast components identified in the Draft IASR as interim. These components were discussed and consulted on (through an "FRG Consultation", inviting written submissions) prior to finalising in the Final 2021 IASR.
- **Multi-sectoral modelling** was undertaken in response to feedback to the Draft IASR on the treatment of decarbonisation. The FRG was consulted on the methodology and outcomes of multi-sectoral modelling.

Consultation through regular discussion

AEMO engages regularly and directly with energy market participants, other market bodies, governments, and other key stakeholders. The ISP and the development of the IASR feature regularly in these discussions, and have been a particular focus of discussions between AEMO and both TNSPs and the AER.

ISP Consumer Panel

AEMO established the 2022 ISP Consumer Panel in November 2020.[7] The National Electricity Rules (NER) require the Panel to provide a report on the Final IASR, including the Panel's "assessment of the evidence and reasons" for AEMO's final positions.[8] The Panel has actively participated in all aspects of the inputs, assumptions and scenarios process since its creation, as well as conducting extensive direct engagement with AEMO.

The Panel's report on the IASR is due to AEMO by 30 September 2021. The report will be published on AEMO's website, once available.

[4] A recording of the webinar and the presentation given is available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement.

[5] AEMO. *Transmission costs for the 2022 ISP*, available at https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

[6] The webinar recording and presentations given are available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement.

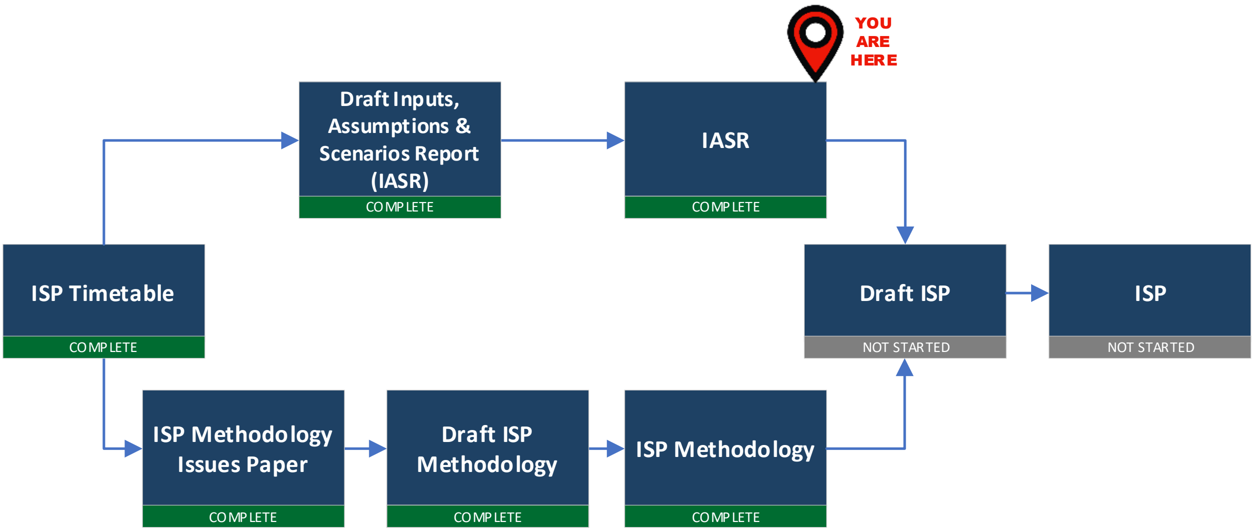
[7] AEMO. *The ISP Consumer* Panel, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/get-involved/consumer-panel.

[8] 5.22.7(e)(1)

1.2 Process to develop the 2022 ISP

AEMO develops and publishes the ISP at least every two years. As shown in Figure 1, the IASR is one of two streams of preliminary activities, with the development of the ISP Methodology representing an interrelated consultation process. Both the ISP Methodology and the IASR are published by 30 July 2021.

Figure 1 Parallel ISP consultations



The actionable ISP framework and associated AER guidelines apply to the development of the 2022 ISP for the first time.[9] The framework includes obligations set out in the Rules and the AER's *Forecasting Best Practice Guidelines* and *Cost Benefit Analysis Guidelines*, AER transparency reviews, TNSP reporting on preparatory activities and the involvement of the ISP Consumer Panel.

Within this framework, and in consultation with stakeholders, AEMO designs and conducts the process to develop the ISP.

Figure 2 below provides a visual representation of this process, including both the elements of the regulatory framework (in blue, red and green boxes) and the activities undertaken by AEMO and stakeholders (in white boxes). Figure 2 also identifies those steps that are complete.

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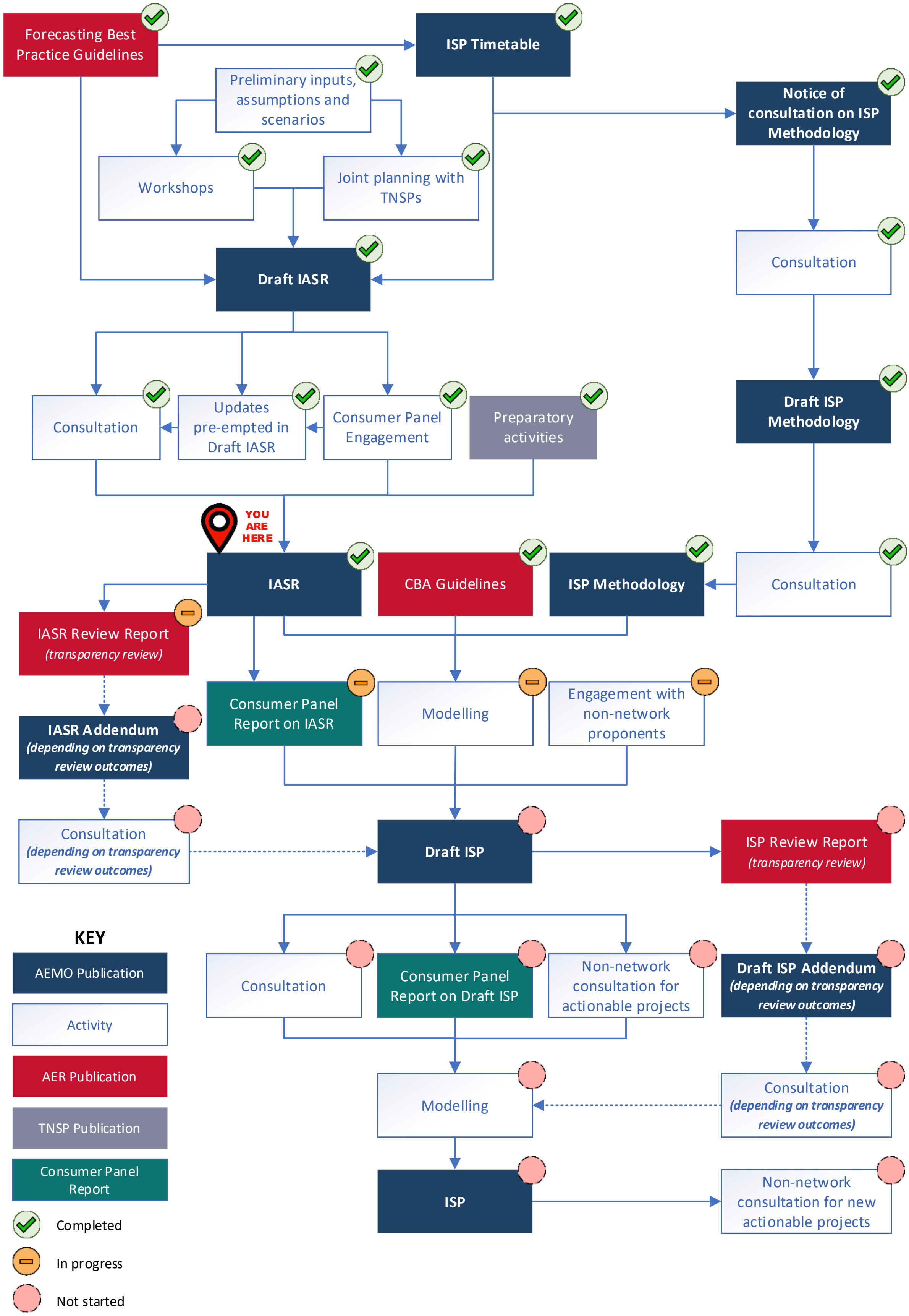
[9] The 'actionable ISP Rules' commenced on 1 July 2020. See https://energyministers.gov.au/publications/actionable-isp-final-rule-recommendation. The 2020 ISP, published on 30 July 2020, was deemed compliant with these new rules (as per NER clause 11.126.2). Clause 5.22.5 of the Rules require the AER to publish guidelines to make the ISP actionable, namely, the Cost Benefit Analysis Guidelines and the Forecasting Best Practice Guidelines. The AER published these guidelines on 25 August 2020. See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable/final-decision.

Figure 2 The ISP process



1.3 Related materials

The Final 2021 IASR documents all publications related to that report – please refer to Section 1.2.

All materials related to the development of the IASR, including the reports and stakeholder submissions, are available on AEMO's website at: https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios.

2. Summary of feedback

2.1 Submissions

Submissions to Draft IASR

AEMO received submissions from 47 stakeholders on the Draft 2021 IASR. These submissions are listed in Table 1, below. In total, 43 stakeholders provided written submissions. In addition, AEMO provided energy consumer advocates with the opportunity to provide verbal submissions to the Draft IASR. Four stakeholders provided additional submissions in this way, as shown in Table 1.

Submissions covered a broad range of issues, providing AEMO with a comprehensive set of stakeholder perspectives on the inputs, scenarios and assumptions proposed in the Draft 2021 IASR. The key themes in the feedback are outlined in Section 2.2.

AEMO also held a public forum to discuss feedback to the Draft IASR on 3 March, with a peak attendance of 94 stakeholders.

Table 1 List of stakeholders who provided formal feedback to the Draft IASR

Australian Conservation Foundation (ACF)	Energy Networks Australia (ENA)	Origin Energy (Origin)
Australian Council of Social Service (ACOSS) (verbal)	Energy Queensland (EQ)	Oscar Archer
Australian Gas Infrastructure Group (AGIG)	Futureye	Powerlink Queensland (Powerlink)
Australian Industry Group (Ai Group) (verbal)	GE Renewable Energy (GE)	Public Interest Advocacy Centre (PIAC)
Australian Pipelines & Gas Association (APGA)	Havyatt Associates (Havyatt)	Queensland Energy Users Network (QEUN) (verbal)
AusNet Services	Hydro Tasmania	Queensland Farmers' Federation (QFF) (verbal)
Bright New World	Hydrostor A-CAES (Hydrostor)	Renewable Energy Systems Australia (RES)
Central Queensland Power (CQP)	Infigen Energy (Infigen)	SA Government – Department for Energy and Mining (SA Govt)
Centre for Policy Development (CPD)	Institute of Energy Economics and Financial Analysis (IEEFA)	Senator Gerard Rennick
Climate Council (CC)	ISP Consumer Panel consumer Panel)	Sligar and Associates (Sligar)
Delta Electricity (Delta)	Major Energy Users Inc (MEU)	Star of the South
Down Under Nuclear Energy (DUNE)	Maritime Union of Australia (MUA)	Total Environment Centre (TEC)/Renew
ElectraNet	MM Technology (MMTech)	TasNetworks

EnergyAustralia (EA)	Nature Conservation Council (NCC)	Walcha Energy
Energy Consumers Australia (ECA)	NSW Minister for Energy and Environment (NSW Govt)	
Energy Estate (EE)	Nuclear for Climate Australia	

Submissions to revised draft scenarios

In light of stakeholder feedback to the Draft IASR, AEMO made significant alternations to the set of proposed scenarios. Given the extent of the changes, AEMO sought further stakeholder feedback on the revised draft scenarios. The revised scenarios were introduced and explained at the Draft IASR webinar on 3 March 2021, with stakeholders then given two weeks to provide written submissions. Fourteen submissions were received, from the organisations listed in Table 2 below.

Table 2 Submissions on revised draft scenarios

AusNet Services	ISP Consumer Panel (Consumer Panel)	Sligar and Associates (Sligar)
AGL Energy Limited (AGL)	Major Energy Users Inc (MEU)	TasNetworks
EnergyAustralia (EA)	Origin Energy (Origin)	Victorian Bioenergy Network
Hydro Tasmania	Public Interest Advocacy Centre (PIAC)	Walcha Energy
Infigen Energy (Infigen)	Shell Energy (Shell)	

Submissions to *Draft 2021 Transmission Cost Report*

Seven submissions were received on the *Draft 2021 Transmission Cost Report*[10], from the organisations listed in Table 3 below. The topics covered included the risk of stranded assets, lack of consideration of environmental externalities, and discussion on the cost estimate classes expected at each stage of the project development process.

A public webinar was held on 10 June 2021, which provided stakeholders with the opportunity to ask questions on the approach to cost estimation and the report.

Table 3 Submissions on revised draft scenarios

Energy Networks Australia (ENA)	Moyne Shire Council	Resist HumeLink
Major Energy Users Inc (MEU)	Origin Energy (Origin)	Shell Energy (Shell)
Public Interest Advocacy Centre (PIAC)		

AEMO thanks all stakeholders who provided submissions to the IASR process.

[10] AEMO. *2021 Transmission Cost Report*, available at: https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

2.2 Summary of key themes

Submissions to Draft IASR

Figure 3 below shows the topics about which stakeholders commented and the relative volume of feedback on each issue. The left side of the figure divides feedback into high-level topics, while the right side of the figure provides a more detailed breakdown of the feedback provided on generator inputs and assumptions.

Figure 3 Topics of interest

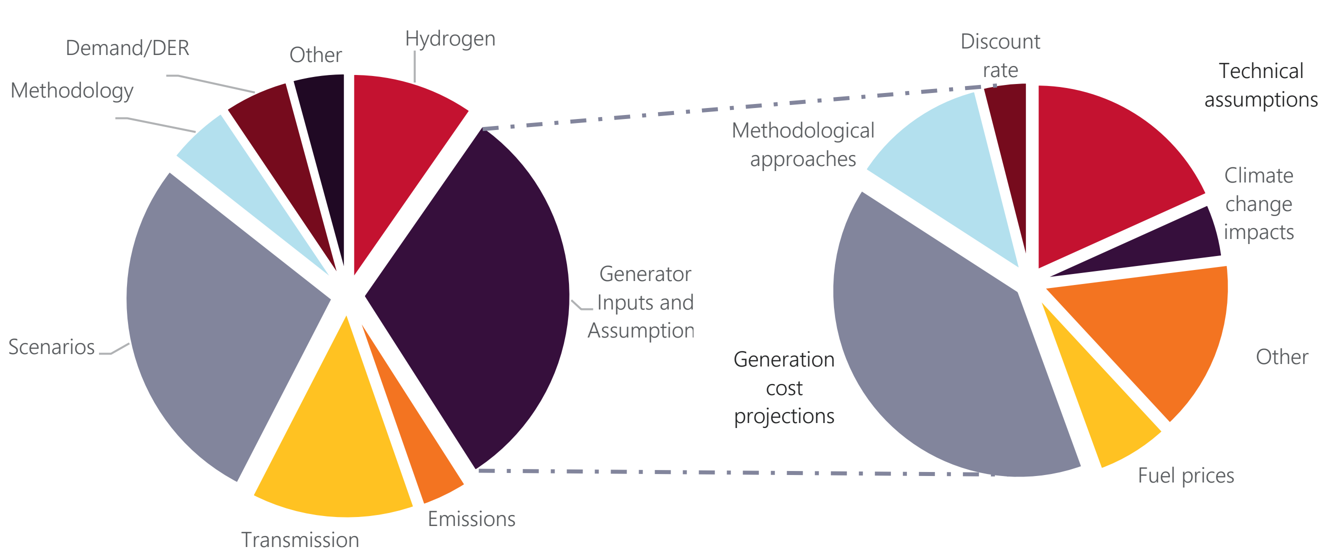


Table 4 provides an overview of the key themes that emerged from written submissions to the Draft IASR and the stakeholders who commented in those areas.

The full explanation of AEMO's considerations is provided in subsequent chapters of this report:

- Section 3 of this report provides more detail on stakeholder engagement in the scenario development process, including AEMO's consideration of submissions to both the Draft IASR and the updated scenario collection.
- Section 4 then describes the changes made between the Draft and Final IASR.
- Section 5 provides AEMO's consideration of the other issues that were raised in stakeholder submissions.

Table 4 Key themes from submissions to the Draft IASR

Theme	Description	Submitter(s)
Central scenario	Central scenario does not include sufficiently ambitious reductions in carbon emissions. State Government commitments to reach net-zero emissions by 2050 (and the Paris Agreement) should be part of the Central Scenario, or in another scenario if the Central Scenario is not able to incorporate these settings.	ACF, ACOSS, AGIG, AusNet Services, EA, ECA, ENA, Havyatt, Infigen, Consumer Panel, MEU, NCC, PIAC, RES, TEC, SA Govt, NSW Govt
Emissions in the scenarios	The extent and pace of decarbonisation need to be a major focus, reflecting the view that this is the greatest source of sectoral uncertainty. Scenarios should have a more ambitious upper bound and/or reflect more rapid changes in policy	ACF, ENA, Havyatt, Infigen, Consumer Panel, PIAC.

Theme	Description	Submitter(s)
Diversified Technology scenario	The scenario is not plausible or internally consistent and does not meet AEMO's criteria for inclusion. The scenario should be abandoned.	ACF, ACOSS, Origin, PIAC
	Low gas prices should be considered in a different way that is explicitly disclosed	CC, Hydro Tas
Additional sensitivities and scenarios	Additional sensitivities were proposed: • Higher transmission cost sensitivity • Delay to Snowy 2.0 • Delay in transmission investments while coal-fired generators retire • Off-shore wind development • Industrial load closure(s) • High decarbonisation in a low-growth world • Decentralisation, with increased DER (and companion policies)	Consumer Panel, Delta, Hydro Tas, CC, MUA, EA, ACF
NEM emissions	A pro-rata allocation of economy-wide emissions is not appropriate, given views that the electricity sector will have to reduce emissions at a greater pace than other sectors	NCC, ACF, Infigen, HT, Walcha, ACOSS
	Concerns with the use of the Land-Use Change and Forestry (LULUCF) sector to balance leftover emissions in the energy sector	ACF, ENA, Havyatt
Climate change impacts	Recommend AEMO review firmness assumptions for inverter connected equipment and performance of underlying wind resources during extreme temperatures	EA
	Recommend AEMO increase focus on climate change impacts for each scenario (i.e. implication of climate change on electricity sector)	TEC
	AEMO should develop synthetic weather traces to better reflect extreme weather events, which will inform generator assumptions and transmission builds	TasNetworks
	AEMO should increase transparency and accessibility of information regarding the effects of climate change on the energy system	PIAC
Fuel prices	Concern about a lack of transparency regarding how gas price projections have been developed by AEMO's consultant, Lewis Gray Advisory (LGA)	Consumer Panel
	AEMO should reassess coal prices projections, specifically volume constraints	EA
	AEMO should review assumed coal and gas prices in the high decarbonisation scenarios	CC
Discount rate	AEMO should calculate a commercial private sector rate, rather than rely on TNSP revenue determinations	Consumer Panel
	More analysis needed regarding the assumption of a lower discount rate in the Slow Growth scenario. Suggest a higher rate in the Export Superpower and Sustainable Growth scenarios might be appropriate	Consumer Panel
	AEMO's proposal to lower the weighted average cost of capital (WACC) for projects that are part of the NSW Government's Electricity Infrastructure Roadmap by 2% needs further explanation	Consumer Panel
	AEMO should consider alternative discount rates in NSW (EA) or argued against lower WACCs for generation projects within renewable energy zones (REZs) (ENA)	EA, ENA
Transmission costs (including REZs)	Request AEMO clarity/updates transmission costs following recent projects e.g. Project EnergyConnect, Western VIC augmentation	MEU, SS
	Request more information on how network costs (and the costs of system strength measures required) are calculated	PIAC, EA, MUA, Consumer Panel

Theme	Description	Submitter(s)
Social licence	The need to create appropriate social licence for major new infrastructure projects, such as long transmission lines, must be considered	Futureye, SS, EE, Walcha
New REZs	General support for the new Banana REZ and Hunter REZ	CQP, EE
	Suggest AEMO align REZs with the location of renewable energy industrial precincts	EE
	Do not support the removal of the Southern Tablelands REZ (N4)	EA
Hydrogen scenarios and investment	Non-hydrogen exports should be considered under the Export Superpower scenario to holistically capture Australia's export opportunities	ACF, Walcha
	The term "electrification" and what it means needs clarification, as hydrogen use results in gas infrastructure continuing to be used, despite increased electricity to manufacture hydrogen.	ENA
	Concern about the risk of high investment costs passed onto consumers	ECA, ElectraNet
	Concern about a number of scenario assumptions are underpinned by little supporting evidence, including but not limited to the potential cost competitiveness of hydrogen, or water availability	Consumer Panel, QEUN, Origin, ENA, EE.

Submissions to revised draft scenarios

The following table provides an overview of the responses to the revised set of draft scenarios (reflecting the scenario names that were used when stakeholders were consulted on them).

Table 5 Key themes from submissions to the revised scenario collection

Theme	Description	Submitter(s)
Splitting the Central scenario	General support for addition of Net Zero 2050 scenario	AGL, AusNet Services, EA, PIAC, Sligar
	Net Zero should be the only Central scenario, to avoid confusion and because it is more likely than the Current Trajectory scenario.	Hydro Tas, Infigen, MEU, Origin, Shell, TasNetworks
	AEMO should commence consultation on scenario weightings immediately	Consumer Panel, EA, Shell
Low gas price sensitivity	Support for AEMO's proposal to convert the Diversified Technology scenario into a low gas price sensitivity	AGL, EA, Origin, PIAC
	Support for the retention of the Diversified Technology Scenario	MEU, Shell
Hydrogen	The domestic use of hydrogen in the Hydrogen Superpower scenario is higher than expected and the interaction with this consumption and EV/DER forecasts is questionable	EA, PIAC
Additional sensitivities	Low growth and rapid decarbonisation sensitivity	PIAC, Shell
	A sensitivity with high levels of decentralisation that also considers the level of investment in the distribution network that would be required.	Shell

In addition, verbal feedback from a range of stakeholders indicated that the scenario names were not self-explanatory, were hard to place in relative order of pace of change in the industry, and were not easily comparable to the scenarios used in the 2020 ISP. Consequently, AEMO reconsidered the scenario names to be used in the IASR and 2022 ISP. The table below shows the evolution of scenario names across the consultation period.

Scenario Collection	Draft Inputs, Assumptions and Scenarios Report	Draft IASR webinar	Scenario conclusion
	October – December 2020	March 2021	July 2021
Original collection	Slow Growth	Slow Growth	*Renamed to* **Slow Change**
	Central	*(Scenario removed).*	*(Scenario removed).*
	Sustainable Growth	Sustainable Growth	*Renamed to Step Change*
	Diversified Technology	*(Scenario removed).*	*(Scenario removed).*
	Export Superpower	Export Superpower	*Renamed to Hydrogen Superpower*
Replacing the Central scenario in the Draft IASR	–	Current Trajectory	*Renamed to Steady Progress*
	–	2050 Net Zero	*Renamed to* **Net Zero 2050**

Submissions to *Draft 2021 Transmission Cost Report*

The following table provides an overview of the key themes in responses to the *Draft 2021 Transmission Cost Report*[11].

Table 6 Key themes from submissions to the *Draft 2021 Transmission Cost Report*

Theme	Description	Submitter(s)
The transmission cost review	Stakeholders generally support the initiative.	ENA, Origin, Shell, PIAC, ENA
	Project costs have historically increased as projects mature, and there is a need to avoid that moving forward.	Origin, PIAC, ENA
	The Transmission Cost Database should be regularly maintained.	Origin, PIAC, ENA
	Stakeholders generally supported AEMO's assessment approach for TNSP estimates.	PIAC, Origin
Application of cost estimates	There was not consensus on whether the accuracy stated for individual classes is realistic.	ENA, Shell, MEU
	There was not consensus on the level of accuracy that is appropriate at different stages of the ISP, RIT-T or CPA.	Shell, MEU, ENA,
	There was not consensus on whether a mid-point or upper-end estimate should be applied.	Shell, MEU, ENA
Scope of cost estimate	There was not consensus on including "externalities" such as environmental, visual amenity and farming impacts.	ENA, Moyne Shire, Shell, ResistHumelink

[11] At https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

Theme	Description	Submitter(s)
Regulatory frameworks	Concern about the risk of high investment costs and land-use costs passed onto consumers.	PIAC, Shell, ResistHumelink
	Recommend changes to the regulatory framework to provide more protection for consumers.	PIAC, Shell
Statement of identified need	Recommend that a statement of identified need should be included for all augmentation options.	Shell, MEU and ENA
Flow Paths and Augmentations	Further consideration of non-network options should be made.	Shell, ResistHumelink

3. Stakeholder engagement on scenario development

This section provides detail on the stakeholder feedback received at each stage of AEMO's consultation. It describes the feedback using the scenario names that were used in each phase of consultation, rather than the revised scenario names that have been concluded.

3.1 Summary of scenarios proposed in the Draft IASR

The scenarios proposed in the Draft IASR were centred around a **Central** scenario that represents AEMO's baseline view of all key economic, policy and technical drivers to impact the energy landscape in the next twenty or more years. The Central scenario reflected current and likely future trends in energy consumption, consumer energy investments, and technology costs, and included all current environmental and energy policies[12] across the NEM jurisdictions (provided the policy has been sufficiently developed to enable AEMO to identify its impacts on the power system).

To complement the Central scenario, AEMO proposed the following four scenarios:

- **Sustainable Growth** – reflecting a possible future world that encompasses high global and domestic decarbonisation ambitions, aligned with strong consumer action on distributed energy resources (DER), and higher levels of electrification of other sectors. This would be supported by strong economic and population growth.
- **Slow Growth** – reflecting a possible future world that encompasses prolonged lower levels of economic growth following the global COVID-19 pandemic, and increasing probability of industrial load closures. Included in this scenario would be targeted stimulus to aid the recovery from COVID-19, that increases the uptake of distributed PV initially, and without direct policy for long-term decarbonisation.
- **Diversified Technology** – reflecting a possible future world that encompasses lower domestic gas prices due to Government incentives and interventions. Higher global investment in alternative low emissions technologies and local research and development in carbon capture and storage (CCS) provide opportunities for greater dispatchable technology diversity than other scenarios.
- **Export Superpower** – reflecting a possible future world that encompasses very high levels of global electrification, Australian hydrogen export opportunities, and domestic hydrogen usage that supports low-emission manufacturing, fuelled by strong policy to support growth and strong decarbonisation.

[12] AEMO applies the 'public policy clause' (NER 5.22.3(b)) in determining whether a policy is included in scenarios. For a policy to be included in scenarios, it must be sufficiently developed to enable AEMO to identify its impacts on the power system. There are also 5 criteria that indicate government commitment to a policy.

This section details how AEMO considered the feedback on the scenarios proposed in the Draft IASR in developing the revised set of scenarios that was proposed in the Draft IASR webinar. The scenario names used in this section reflect the names provided in Table 7.

Table 7 Scenario name mapping between Draft IASR and the Draft IASR webinar

Scenario collection	*Draft Inputs, Assumptions and Scenarios Report*	Draft IASR webinar
	October – December 2020	March 2021
Original collection	Slow Growth	Slow Growth
	Central	*(Scenario removed)*
	Sustainable Growth	Sustainable Growth
	Diversified Technology	*(Scenario removed)*
	Export Superpower	Export Superpower
Replacing the Central scenario in the Draft IASR	–	Current Trajectory
	–	2050 Net Zero

3.2 Summary of material issues from the Draft IASR consultation

The key material issues raised by Consulted Persons regarding the proposed scenarios in the consultation to the Draft IASR are summarised in this section. These submissions influenced AEMO's amended collection of scenarios.

3.2.1 Decarbonisation ambition across the scenarios

AEMO noted that to include a public policy as "committed" for inclusion in all scenarios, it needed to be sufficiently developed to enable AEMO to identify the impacts of it on the power system, and meet at least one of the following conditions, required by NER 5.22.3(b):

- A commitment has been made in an international agreement to implement that policy.
- That policy has been enacted in legislation.
- There is a regulatory obligation in relation to that policy.
- There is material funding allocated to that policy in a budget of the relevant participating jurisdiction.
- The Ministerial Council of Energy (MCE) has advised AEMO to incorporate the policy.

Many stakeholders submitted that the Central scenario omitted various jurisdictional targets that required each jurisdiction to achieve net zero emissions by 2050. Stakeholders also submitted that a broader national commitment exists within the requirements of Australia's commitment to the Paris Agreement.

Many stakeholders (MEU, ECA, PIAC, ACOSS, Havyatt, Infigen Energy, ENA, AGIG, ACF, NCC, TEC, CPD) argued that the **Central scenario** should explicitly include a net zero by 2050 target, primarily due to the commitments of state and territory governments, but some also pointing to inconsistencies with the Paris Agreement. The governments of South Australia and New South Wales both instead argued for the inclusion of an additional scenario that reflects the state-based net zero commitments.

The ISP Consumer Panel stated that in their opinion the issue of decarbonisation was not appropriately dealt with in the **Central scenario** and recommended further engagement on the issue.

A number of submissions argued that the **scenario collection** should explore more ambitious bookends, particularly with regards to the speed of decarbonisation (ACF, PIAC, Infigen Energy).

With regards to the **Sustainable Growth** scenario:

- The ISP Consumer Panel considered that the scenario's core parameters of high economic and population growth paired with strong decarbonisation ambition was inappropriate. Rather, they suggested that the strong decarbonisation should not rely upon, or be implied to drive, stronger economic outcomes.
- Stakeholders also proposed that the scenario should incorporate a greater capacity for hydrogen development in this scenario than was proposed (Hydrogen Growth, Hydro Tasmania, TasNetworks).
- Stakeholders considered that the level of decarbonisation ambition that was proposed by AEMO was too low (ISP Consumer Panel, Walcha Energy).

The ACF suggested that a low growth/high decarbonisation scenario should be explored.

Several stakeholders considered that it was of critical importance for **economy-wide emissions reduction** to be considered, in order to identify the impact on the energy sector. One outcome frequently raised (by the ISP Consumer Panel, Infigen Energy, PIAC) was the potential impact of significant fuel switching from gas to electricity as a result of decarbonisation objectives. Other submissions (Havyatt, ACOSS, ACF, NCC, Climate Council, Walcha Energy, Hydro Tasmania) also reiterated the need to understand the potential need for more rapid emissions reductions from the electricity sector as part of an economy-wide trajectory, and/or questioned the approach proposed in the Draft IASR to determining a NEM carbon budget in some scenarios.

A number of submissions argued for AEMO to seek engagement with experts in the field. The Climate Council suggested AEMO should engage recognised experts to ensure the implementation and development of Australian and NEM carbon budgets was correct, while Infigen suggested engaging external experts (such as the CSIRO and ClimateWorks Australia (CWA)) to develop emission projections for Australia and sectoral emissions projections, including for the NEM.

Finally, the ISP Consumer Panel suggested that aligning to emission outcomes is a complex but fundamental input into the ISP which required more rigor and analysis. They suggested AEMO seek peer review from an independent expert to validate the facts and trends used to inform emissions assumptions.

3.2.2 Diversified Technology scenario

Several stakeholders suggested that AEMO did not provide sufficient clarity regarding the rationale for the scenario's domestic emissions inaction while international decarbonisation was strong (MUA, Climate Council, Havyatt, TEC), and others considered that the scenario was internally inconsistent (ISP Consumer Panel, Origin Energy, PIAC).

Stakeholders also considered the scenario an implausible and internally inconsistent future world (ACF, PIAC, Origin Energy, Walcha), and considered that it should be removed from the collection of scenarios to be modelled in the ISP (PIAC, ACOSS, ACF and TEC).

A key proposed component of the scenario was the effect of lower gas prices, to understand the impact this may have on broader investments and consumer benefits. The Climate Council suggested that there was a need to more clearly define the drivers and mechanism for the proposed lower gas prices.

In contrast, some stakeholders considered that the insight that may be gained from modelling lower gas prices should be retained, either in a scenario or as a distinct sensitivity (QEUN, MEU, Origin Energy).

3.2.3 Export Superpower scenario and hydrogen assumptions

Support for this scenario was expressed by several stakeholders (Origin Energy, Walcha, EA, ElectraNet). Additional feedback on the scenario included:

- The uncertainties that exist regarding the developments required for this future to eventuate are too great at present, and little weight should be applied to the insights this scenario will provide (Consumer Panel, EA).
- Cost impacts to consumers should be thoroughly investigated (ElectraNet, ECA).

- The scenario should more clearly focus on the opportunities presented by a hydrogen economy by aligning the level of climate ambition to the Sustainable Growth scenario (ENA).

3.2.4 Slow Growth scenario

Stakeholders provided a mixed reception to this scenario – some stakeholders suggested that this scenario is highly unlikely/implausible (Infigen Energy, ACF, Walcha) while one stakeholder deemed this scenario to be one of the more likely developments (Sligar and Associates).

There were several comments about different aspects of the scenario, with stakeholders suggesting that the scenario should be combined with the Central scenario into a "Policy Inaction" scenario (Infigen Energy), and that AEMO should consider the implications potential government intervention to support industrial loads would have on resisting the expected decline of operational demand in this scenario (Hydro Tasmania).

3.2.5 Risk scenarios and additional sensitivities

In addition to the five proposed scenarios, the Draft IASR proposed a set of possible risk scenarios which would potentially be used to further explore the risk of over- or under-investment. These related to risks associated with early coal closures, alternative levels of DER uptake, as well as developments regarding specific transmission infrastructure.

Stakeholders suggested a number of additional risk scenarios and/or sensitivities for AEMO to consider, including:

- Higher transmission cost sensitivity (Delta Electricity, ISP Consumer Panel).
- A delayed Snowy 2.0 sensitivity (Hydro Tasmania).
- Delayed transmission investments coinciding with coal-fired generation retirements sensitivity (Hydro Tasmania).
- Decentralised future, driven by reduced DER costs and new policies (ISP Consumer Panel).
- Offshore wind sensitivities (MUA, Climate Council).
- Load closures sensitivity (EA).

3.3 AEMO's consideration of the stakeholder feedback on the Draft IASR

AEMO considered the feedback provided by stakeholders, summarised in the above sections. AEMO proposed several changes that were important to reflect within the scenario collection, and proceeded to adjust the scenarios accordingly. In particular, the feedback received on decarbonisation, and public statements regarding it being a driver affecting the Federal Government's climate and energy policies over the coming decades, led AEMO towards proposing a greater emphasis on decarbonisation dispersion within its core scenarios.

AEMO has noted stakeholders' views that the Central scenario omitted the ambitions of various jurisdictions to achieve net zero emissions by 2050, and the broader national long-term commitment that exists given Australia's commitment to the Paris Agreement.

In AEMO's view, while Australia has committed to the global goal of limiting temperature increases to "well below 2°C, and preferably to 1.5°C" compared to pre-industrial levels, the level of ambition (in terms of pace and scope for emissions reductions) in Australia, and in particular the impact on the energy sector, is not yet clear. The Paris Agreement requires countries to submit Nationally Determined Contributions (NDCs) every five years, which detail its efforts to reduce emissions. All scenarios reflect (and some exceed) the Australian Government's latest NDC (submitted in 2020) under the Paris Agreement.

While NER 5.22.3(b) allows inclusion of public policies where "a commitment has been made in an international agreement to implement that policy", AEMO does not consider that Australia's commitment is provided in sufficient detail to include beyond the existing NDC level of action in all scenarios.

Additionally, some jurisdictional aspirational net zero targets do not meet the criteria as required by NER 5.22.3(b). Specifically, while many jurisdictions have announced a net zero ambition, few have enacted the specific actions to achieve this in legislation, or provided material public funding to achieve the objective. It is also unclear how these aspirational targets will impact the power system throughout the planning horizon, or the extent of electrification of other sectors that could materially change the power system needs. As a result, AEMO considers it prudent to account for uncertainties regarding both the rate of emission reductions and the potential mechanism (such as the use of offsets, or targeted sectoral approaches) by varying the speed of decarbonisation across the scenarios, rather than impose a consistent, yet uncertain trajectory across all scenarios.

Additional responses to provided feedback are as follows:

- In response to stakeholder feedback, AEMO considered that it was important for the scenario collection to include consideration of **net zero ambition by 2050**.
- In response to feedback regarding the speed of decarbonisation, AEMO engaged multi-sectoral modelling to appropriately inform emissions reductions activities across Australia's economy to support the scale of electrification and emissions reduction that may impact the energy sector across the scenario collection.
- In response to the Consumer Panel's feedback on economic growth and decarbonisation alignment, AEMO adjusted the Sustainable Growth scenario to have a central economic outlook, thereby increasing the utility available for inter-scenario comparisons regarding the investment impact of stronger decarbonisation objectives.
- In response to feedback regarding hydrogen development across scenarios other than just the Export Superpower scenario, AEMO considered that all scenarios may have domestic hydrogen uptake potential, and should not be limited in this regard. The Export Superpower scenario however is retained as the sole scenario that develops a strong hydrogen export sector *that connects to the NEM*.
- AEMO considered the feedback regarding the Diversified Technology scenario, and agreed that a gas price sensitivity would provide greater utility to support decision making than a bespoke scenario that incorporated this amongst other drivers and inadvertently introduced internal inconsistencies.
- Regarding the Slow Growth scenario, AEMO does not consider it appropriate that the bookends ignore the possibility for slower economic growth, and slower decarbonisation ambition. AEMO considers this an important scenario to retain to identify the potential risks of over- or under-investment.

AEMO therefore developed revised scenario narratives and adjusted the scenario collection, and determined an additional consultation window was essential to consolidate the proposed amendments. These revised scenario narratives are described in the following section.

Further details on the responses to the submissions are provided in Section 5.1.

3.4 Subsequent consultation on scenario revisions

After considering the feedback on the scenarios provided by stakeholders to the Draft IASR consultation, AEMO proposed a number of amendments to the scenario collection. These amendments were documented and presented in a webinar to stakeholders on 3 March 2021. Following the webinar, stakeholders were provided an additional opportunity for written submissions.

This section details AEMO's consideration of the feedback provided on the revised set of scenarios.

Note that this section reflects on feedback on the scenarios as they appeared in the Draft IASR webinar held in March 2021. To be more informative and facilitate greater appreciation of the relative differences, the final scenario names are different to those described in that webinar, with the changes shown in Table 8.

Table 8 Scenario name mapping across development and consultation phases

Scenario Collection	Draft IASR webinar	Scenario conclusion
	March 2021	July 2021
Original collection	Slow Growth	*Renamed to* **Slow Change**
	Sustainable Growth	*Renamed to Step Change*
	Export Superpower	*Renamed to Hydrogen Superpower*
Newly added	Current Trajectory	*Renamed to Steady Progress*
	2050 Net Zero	*Renamed to* **Net Zero 2050**

3.4.1 Removing reference to a Central scenario

As described in Section 3.2.1, AEMO received mostly consistent feedback that the decarbonisation assumptions of the Central scenario as described in the Draft IASR needed to be changed, or an alternative scenario with a net zero 2050 target should be added.

Although all NEM states and territories have some form of 2050 net zero emissions target or aspiration, in most cases these are not well specified, instead representing statements of intent or ambition, and are not yet supported by legislation (with the exception of Victoria and the Australian Capital Territory) or significant, budgeted funding mechanisms to the extent required to achieve the objective.

The Federal Government has reiterated that progress towards net zero emissions remains a priority that will rely on (domestic and global) technological developments. While it does not represent an established Federal Government policy, it is the government's preference for this to be achieved "as early as possible, and preferably by 2050"[13].

Given this uncertainty, AEMO proposed to replace the Central scenario with two alternatives, a '**Current Trajectory**' scenario and a '**2050 Net Zero**' scenario. Both scenarios would consider the current national 2030 emissions reduction target of 26-28%, in addition to existing policies such as the state-based renewable energy targets.

Beyond 2030, the scenarios diverge:

- The 'Current Trajectory' scenario was proposed to primarily be driven by consumer preferences, age-based coal retirements, as well as economic drivers of retirement and investment.
- The 2050 Net Zero scenario was proposed to explicitly target an economy-wide emissions trajectory which transitions from the 2030 target towards net zero by 2050. This scenario would incorporate greater levels of decarbonisation and electrification over time as a result of technological developments that enable economy-wide emission reductions (informed by multi-sectoral modelling, described further below). While this would result in an emission level by 2050 similar to the Sustainable Growth scenario (now the Step Change scenario), delayed action in this scenario would provide a key point of difference.

In other aspects, the two scenarios would be consistent, incorporating central estimates for economic and population growth, DER uptake and including all sufficiently developed government policies.

*The Current Trajectory scenario has been renamed to '**Steady Progress**' to better reflect the steady decline in economy-wide greenhouse gas emissions projected in this scenario.*

[13] The Hon Scott Morrison MP, National Press Club address, 1 February 2021, at https://www.pm.gov.au/media/address-national-press-club-barton-act.

3.4.2 Adjustments to the Sustainable Growth scenario (now the Step Change scenario)

Given the high level of stakeholder focus on exploring decarbonisation as the key source of sectoral uncertainty, AEMO proposed a revision to the Sustainable Growth scenario that maintained the central level of economic and population growth drivers, consistent with the Current Trajectory and 2050 Net Zero scenarios.

The scenario retained a focus on high DER uptake, but focused more clearly on understanding the impacts of stronger decarbonisation without varying other assumptions such as economic growth. The pace of transition in the scenario is consistent with global activities to limit temperature rises to 2° by 2100[14], with economy-wide emissions levels equivalent to net zero before 2050.

*This scenario has been renamed to '**Step Change'** to make it clearer that this scenario reflects a deeper cut in emissions faster than either the Steady Progress scenario or the Net Zero 2050 scenario. Further, its narrative is closely aligned to the Step Change scenario used in the 2020 ISP*

3.4.3 Introduction of a Rapid Decarbonisation sensitivity (now Strong Electrification)

AEMO reflected that the scenario collection, after the Sustainable Growth adjustments, limited the comparability of the Export Superpower scenario to other scenarios. To identify the impacts of an export-scale hydrogen economy, the closest comparison would be the Sustainable Growth scenario, however this would now require comparisons with differing levels of decarbonisation ambition and economic activity.

AEMO proposed the introduction of a Rapid Decarbonisation sensitivity. The design of the sensitivity would mirror much of the Export Superpower scenario, without the development of significant hydrogen production. The sensitivity would still target a rapid pace of change affecting the energy sector, consistent with strong global action in limiting temperature rise to 1.5°, but it would require greater investment in electrification or other technologies with lesser hydrogen production capability. The sensitivity therefore would provide insight on the challenges and/or benefits that grid-scale hydrogen developments may provide to the power system, as well as the scale of investment in alternatives – particularly electrification and energy efficiency – without cheap access to hydrogen while achieving deep economy-wide emissions reductions.

*This sensitivity has been renamed to '**Strong Electrification**' to reflect that, in the absence of ubiquitous hydrogen availability, other sectors would need to rely more heavily on electrification (among other things) to achieve the same economy-wide emission reductions.*

3.4.4 Transition of Diversified Technology scenario to a Low gas price sensitivity

Given the balance of feedback on the Diversified Technology scenario, AEMO proposed converting the scenario into a low gas price sensitivity with other settings consistent with the core scenario that this sensitivity is assessed against. In converting the scenario to a sensitivity, greater insight can be provided on the impact to generation and transmission investments, and consumer benefits, from lowering gas prices.

3.5 Multi-sectoral modelling to inform decarbonisation pathways

In order to appropriately inform the settings to be used within the scenarios, AEMO engaged the CSIRO and ClimateWorks Australia to forecast the efficient investments required across Australia's sectoral economy to align with the decarbonisation narratives of the scenarios, and the associated impacts on the electricity sector. The modelling informed the growth in NEM consumption and demand due to the electrification of existing and new loads not presently associated with electricity use, and the emissions abatement required within the NEM considering the broader economy-wide emissions abatement activities. This considered various alternative investments and actions available, including sequestration offsets, energy efficiency and fuel switching (among others).

[14] Consistent with international practice, temperature changes are referenced to the year 2100.

Each scenario, except the Slow Change and Steady Progress scenarios[15], would be informed by the insights provided from the multi-sectoral modelling:

- For the **Steady Progress** and **Net Zero 2050** scenarios:
  - Until 2030, these scenarios will be similarly informed by multi-sectoral modelling, informing the pace of electrification that is expected given current policy and technological trends.
  - Beyond 2030, the Net Zero 2050 scenario will incorporate electrification influenced by technological advances as the economy strives to achieve net zero emissions by 2050. Conversely, the Steady Progress scenario will limit its consideration to those actions influenced by the public policies included in the scenario that meet the "committed' policy criteria.
- The **Step Change** scenario and **Hydrogen Superpower** scenarios would be informed by the activities required across sectors to electrify or embrace low emissions alternatives informed by each scenario/sensitivity's decarbonisation ambition. This results in strong levels of electrification and lesser carbon budgets over the entire modelling horizon.

3.6 Feedback on the revised scenarios

This section presents the key points raised in the submissions on the revised scenarios.

Splitting up the Central scenario

- There was general support from stakeholders for the addition of a Net Zero 2050 scenario as the narrative aligns with state and corporate targets, and with recent statements by the Federal Government (Sligar and Associates, PIAC, AGL, EA, AusNet Services). Some stakeholders considered that the Net Zero 2050 scenario should be the only Central scenario, as they considered it to be the "more likely" future. They considered that this would potentially avoid the confusion of having separate "Central" scenarios (MEU, Origin Energy, Hydro Tasmania, Shell Energy, TasNetworks, Infigen Energy).
- In addition, several stakeholders proposed that AEMO decide on a "most likely" scenario and to commence the consultation process on determining scenario weightings (ISP Consumer Panel, EA, Shell Energy).

AEMO response: AEMO consulted on a proposed process for developing scenario weightings through the ISP Methodology Consultation. This will allow for further consultation on scenario weightings later in 2021, as more information is available to influence which scenarios are considered more/less likely than others. The scenario weightings themselves do not influence the modelling approach applied for the ISP.

AEMO considers that it remains valuable to retain both the Steady Progress (originally named 'Current Trajectory') and Net Zero 2050 (originally named '2050 Net Zero') scenarios, given the current uncertainty around the speed and scale of economy-wide decarbonisation, as well as the influence that state targets and corporate ambitions have on the energy sector. These scenarios were developed to replace the original Central scenario, as described in Section 3.4.1 above.

Low gas price sensitivity

- There were a number of stakeholders who supported AEMO's proposal to convert the Diversified Technology to a low gas price sensitivity (PIAC, AGL, EA, Origin). PIAC also expressed concern that the low gas price sensitivity may be unrealistic and not compatible with international climate obligations.
- Shell Energy and MEU supported the retention of the Diversified Technology scenario as a plausible bookend scenario, in line with government stated ambitions.

[15] The Slow Change and Steady Progress scenarios do not impose specific economy-wide emissions reduction targets and so no multi-sectoral modelling outputs influence those scenarios' consumption forecasts.

AEMO response: AEMO considers that the conversion of the Diversified Technology scenario to a low gas price sensitivity remains appropriate, as this will more clearly allow assessment of how sensitive the optimal development path (ODP) is to variations in gas prices. This scenario as originally formulated would likely have had a low weighting, limiting its effectiveness as a bookend scenario. Converting it to a focused sensitivity on gas prices will provide stakeholders with better information on the robustness of the ODP to variations in gas prices.

The *ISP Methodology* outlines how the sensitivity will be used in informing the determination of the ODP.

Other scenarios and sensitivities

AEMO also received a number of stakeholder comments regarding the other scenarios proposed:

- There were suggestions that the domestic use of hydrogen in the Hydrogen Superpower scenario is higher than expected (PIAC, EA). The same stakeholders also questioned the interaction between domestic hydrogen consumption with electric vehicles (EVs) and higher DER forecast.
- TasNetworks suggested that the Slow Change scenario should be amalgamated with the Steady Progress scenario, given they are similar in construct

Furthermore, a number of submissions requested further sensitivities as follows:

- A sensitivity which explores a future with low economic growth coupled with high levels of decarbonisation ambitions (Shell Energy) with the latter driven by strong DER uptake (PIAC).
- A sensitivity with high levels of decentralisation which also considers the level of distribution network investment required (Shell Energy).

AEMO response: AEMO has consulted on the appropriate inputs for hydrogen and electrification as part of its stakeholder engagement from the multi-sectoral modelling. The scale of domestic hydrogen development in the Hydrogen Superpower (and other) scenarios is informed by the potential for hydrogen to support decarbonisation across sectors.

AEMO considers that the Steady Progress and Slow Change scenarios differ across a number of key drivers, including economic activity, population growth, and DER uptake. As such, AEMO considers that there is value in keeping both scenarios to adequately explore the risks of over- or under-investment with slower operational consumption growth.

AEMO considers that the majority of the stakeholder suggestions regarding sensitivities are adequately considered within the scenario collection:

- By aligning the Step Change scenario with central growth assumptions rather than high growth assumptions, the objective of the suggested low-growth, high decarbonisation ambition sensitivity is at least partly addressed. Furthermore, the inclusion of higher short-term DER uptake in the Slow Growth scenario also partly addresses PIAC's concerns.
- AEMO agrees that considering a decentralised future is an important potential influence on investments. AEMO has included a High DER sensitivity within the Sensitivity collection, to consider the impacts of even greater decentralisation on other investments. This sensitivity is described in Section 2.4 of the IASR.
- Transmission cost uncertainties may have a material impact on the ODP, and AEMO's process for accounting for these uncertainties is documented in the *ISP Methodology*.

Further details on the responses to the submissions are provided in Section 5.2.

4. Summary of changes – inputs and assumptions

This section summarises the key developments and changes in inputs and assumptions since the draft IASR.

Public policy settings

AEMO has continued to apply the criteria set out in the NER for determining whether a government policy should be included in scenarios.

Since the Draft IASR, the New South Wales Electricity Infrastructure Roadmap has progressed to the point where a recommended pathway will soon be identified. The final IASR has refined the description of the assumptions applied as a result of this policy to better reflect the chosen pathway.

AEMO acknowledges feedback from some stakeholders that the merits and impacts of public policies and pathways should be assessed within the ISP, but considers that the role of the ISP is not to prosecute the merits of policies but rather to understand their impact on the power system and plan the development of the system in a way that meets the policy objective at least cost to consumers.

However, given the uncertainty around cost recovery arrangements for Marinus Link and the influence of this project on how the Tasmanian Renewable Energy Target (TRET) will be delivered, AEMO will include an event-driven scenario which tests the removal of both Marinus Link and the TRET from key scenarios. This will provide both the ability to understand how the ODP may need to evolve if cost recovery arrangements are not able to be resolved, as well as providing an alternative counterfactual scenario which can be used to understand the materiality of the TRET to market benefits of Marinus Link.

Similar event-driven scenarios have been formulated for other strategic transmission projects identified as actionable ISP projects in the 2020 ISP. These "events" represent clearly observable and reasonably probable decisions that may directly influence the commercial feasibility or commitment status of projects such as HumeLink and VNI West, and consequently materially change the market benefits of a candidate development path (CDP) identified in the ISP.

AEMO's development of energy efficiency and DER forecasts has endeavoured to include all recent relevant policy announcements.

Emissions and climate outcomes and targets

AEMO received valuable feedback from several stakeholders around the approach to modelling decarbonisation described in the Draft IASR. As outlined in Section 3.5, AEMO engaged the CSIRO and ClimateWorks Australia to forecast the efficient investments required across Australia's sectoral economy to achieve the decarbonisation narratives of the scenarios, and the associated impacts on the electricity sector. The modelling identified growth in NEM consumption and demand due to the electrification of existing and new loads not presently associated with electricity use, and the NEM emission reductions required under each scenario considering the broader economy-wide emissions abatement activities. This considered various options available or emerging across sectors, including sequestration offsets, energy efficiency and fuel switching (among others).

AEMO's approach to determining a carbon budget for the NEM (if appropriate in the given scenario) is now informed by this multi-sectoral modelling, specified in the 2021 IASR, rather than using a pro-rata approach (as described in the Draft IASR).

Energy consumption and demand

The majority of the inputs related to electricity consumption and demand presented in the Draft IASR were interim, reflecting forecasts developed in August 2020 or earlier for the 2020 *Electricity Statement of Opportunities*. Since the Draft IASR, AEMO has updated and finalised all interim inputs and assumptions which drive these forecasts, and consulted on these updates, primarily through the FRG.

The updated interim inputs address some key areas of feedback that were provided on the forecasts presented in the Draft IASR, in particular, the inclusion of higher distributed PV uptake, and potential electrification in scenarios with rapid decarbonisation ambitions.

Existing generator and storage assumptions

One of the key sources of information on existing generator and storage projects is AEMO's Generation Information Page. This information is updated quarterly based on engagement with market participants and project developers. The 2021 IASR utilises the most recently published version as a means of identifying existing, committed and anticipated projects.

Since the Draft IASR, AEMO has revised its assumptions on coal fixed and variable operating and maintenance costs based on feedback provided which indicated these costs could be improved. AEMO has removed lumpy refurbishment costs, instead including these in annual fixed operating costs, and revised the assumptions around fixed operating costs based on information provided by participants. AEMO will continue to engage with power station operators to improve these costs and other technical and cost parameters in the future.

AEMO has also revised a number of other technical assumptions for existing generators. AEMO thanks power station operators for providing additional information and/or guidance. AEMO also updated emissions factors based on the suggestion of improved data sources provided by the Climate Council.

New entrant generator assumptions

Many of the inputs and assumptions for new entrant generator assumptions are provided through the GenCost process that is a collaboration between AEMO and the CSIRO. The GenCost report was consulted on in tandem with the Draft IASR, and submissions provided to the Draft IASR, and further direct engagement with stakeholders, were addressed and finalised as part of the Final 2020-21 GenCost publication[16].

The 2021 IASR therefore incorporates these adjustments, notably for solar PV, battery storage, and biomass technologies.

AEMO has also engaged with Hydro Tasmania to source improved cost estimates for the Cethana Pumped Hydro project.

Fuel assumptions

AEMO received detailed feedback on fuel price assumptions published in the Draft IASR, most notably from the ISP Consumer Panel on the gas price forecasts. The key issues raised for the gas prices related primarily to the transparency of the forecasts, rather than their appropriateness or accuracy. AEMO held a further workshop on gas prices in May 2021 to allow stakeholders to more deeply explore and understand the assumptions and methodologies applied by LGA in the development of the forecasts. AEMO also considered stakeholder feedback and lowered the gas prices to be applied in the Low Gas Price sensitivity

[16] At https://www.csiro.au/-/media/EF/Files/GenCost2020-21_FinalReport.pdf.

by $0.30/gigajoule (GJ), resulting in gas prices approximately $3-4/GJ lower than the medium price trajectory provided by AEMO's consultants.

AEMO also received feedback on the coal price forecasts proposed in the Draft IASR and in response has revised the fuel price projections for several New South Wales coal generators.

Financial parameters

The discount rates proposed in the Draft IASR were commented on by several stakeholders, with the primary area of concern being an overreliance on regulatory determinations and concerns that the proposed rates did not reflect the risk of private sector investment in the NEM, as required by the CBA Guidelines. In response to this feedback, AEMO engaged Synergies Economic Consulting to recommend a revised set of assumptions for the discount rate which more explicitly considered the use of commercial discount rates as required by the ISP framework.

The discount rate range in the 2021 IASR considers the recommendations provided by Synergies, which itself considered feedback from several stakeholders. AEMO has also removed deviations from the discount rate associated with government policies and scenarios based on the advice provided by Synergies, and in response to concerns raised by stakeholders.

AEMO has also revised the assumptions for the Value of Customer Reliability (VCR) applied to be based on a weighted average of consumer types in each region based on feedback provided to the Draft IASR.

Climate change factors

A number of stakeholders suggested that greater clarity around the impact of climate change should be provided, and that AEMO should leverage the Electricity Sector Climate Information (ESCI) Project[17]. Since the Draft IASR, AEMO revised the climate change factors to be based on final data newly provided through the ESCI project, now available at http://www.climatechangeinaustralia.gov.au/esci/.

Renewable energy zones

In response to stakeholder feedback, AEMO has added offshore wind zones (OWZ) to the candidate zones for assessment in the ISP for renewable energy development. These new zones are treated in a very similar way to onshore renewable energy zones (REZs), with minor adjustments to the approach to reflect the particular nature of offshore wind projects. AEMO has also modified the boundary of the Gippsland REZ to reflect connection interest and avoid overlapping the adjacent OWZ.

As a result of feedback to the *ISP Methodology*, AEMO has made a significant improvement to the modelling for REZs, by applying a transmission limit approach to modelling network access in REZs rather than using a hosting capacity approach (that is, setting an instantaneous limit on how much generation can be exported from a REZ rather than how much capacity can be built within the REZ). This improvement enables the ISP model to determine an *efficient* amount of generation and network development in REZs that considers the consequences of congestion more explicitly. To accommodate this change, REZ hosting limits have been replaced with REZ transmission limits.

Augmentation options and network modelling

The following network projects have advanced:

- Victoria – New South Wales Interconnector (VNI) Minor and VNI System Integrity Protection Scheme – these transmission projects have progressed from anticipated to committed status.
- VNI Minor and VNI System Integrity Protection Scheme – these transmission projects have progressed from anticipated to committed status.

[17] See https://www.climatechangeinaustralia.gov.au/en/projects/esci/.

- Project EnergyConnect – following the AER's approval of TransGrid and ElectraNet's contingent project applications, Project EnergyConnect has been confirmed as an anticipated project.
- Northern QREZ and Central West Orana REZ Transmission Link have advanced to the anticipated project stage.

Other minor updates include marginal loss factors (MLFs), loss equations, and transmission line failure rates.

Other power system security inputs

In the 2021 IASR and *ISP Methodology*, AEMO has clarified its approach to minimum unit commitment for synchronous generators. Additional detail has been provided on system strength mitigation costing as part of the *2021 Transmission Cost Report*.

AEMO also notes that power system security inputs may be updated to align with the latest advice and information provided through other publications such as the system strength requirements methodology, the inertia requirements methodology, and the Engineering Framework.

Gas modelling

AEMO has leveraged the multi-sectoral modelling from CSIRO and ClimateWorks to consider the feedback provided on the interaction between the gas system and potential hydrogen production and operation. AEMO also thanks stakeholders who highlighted that the draft gas infrastructure assumptions were published prior to the 2021 *Gas Statement of Opportunities* (GSOO), which updated these inputs appropriate for the GSOO.

Hydrogen modelling

AEMO has refined domestic hydrogen consumption projections utilising CSIRO's multi-sectoral model which allows for fuel-switching between various energy sources, including hydrogen. These projections are optimised to achieve least cost within the constraints of the model and scenario. One particular development was the recognition of potential industrial growth, captured by the addition of a new "green steel" industry in the Hydrogen Superpower scenario.

AEMO has adopted different baseload factors for small and large electrolysers based on stakeholder feedback. AEMO has clarified that domestic hydrogen production for industry (new and existing) within the NEM regions that may fuel-switch to hydrogen will be serviced by hydrogen production facilities that use steam-methane reforming (SMR) technology (with or without carbon-capture and storage), or NEM-connected electrolysers. This considers the role the gas distribution system may continue to have and the overlapping geography of the NEM and gas distribution system. In the Slow Change and Steady Progress scenarios, insufficient new hydrogen demand is forecast to lead to material electrolyser developments for domestic purposes and any hydrogen production is assumed to come from SMR, or off-grid for remote applications.

Stakeholder feedback encouraged AEMO to expand the scale of fuel switching towards hydrogen (rather than electricity) in the Hydrogen Superpower scenario. AEMO adjusted up the fuel switching allocation (as reported in the CSIRO report) to reflect a persisting level of hydrogen (rather than electricity) demand for existing gas-connected households, while new houses without an existing gas connection would retain an electrified approach. This increases the proportion of residential consumers remaining gas-connected (consuming hydrogen, or blended hydrogen-natural gas) relative to the multi-sectoral outputs in that scenario.

Finally, feedback from stakeholders has helped confirm the approach and assumptions adopted for how the hydrogen will be modelled. This is less a change, and more a recognition of the rapid development in this area and increasing clarity on approach in a new area of modelling.

Transmission costs

In response to stakeholder feedback to the 2020 ISP, AEMO completed an extensive review of the transmission cost estimation methodology for the 2022 ISP. The goal of this review was to increase the transparency and accuracy of cost estimates for transmission projects considered in the ISP. The approach, component costs and project cost for all projects have been updated via the *2021 Transmission Cost Report* consultation. All of AEMO's cost estimates are published with a comprehensive and transparent breakdown of component costs and risk allowances assumed for preparation of the ISP.

In response to feedback on the consultation, AEMO has introduced two sub-classes within the Class 5 cost estimate level, to reflect the impact of concept vs screening level scope definition within Class 5. This change resulted in an increase to the cost estimate of many conceptual projects (these projects are reported as "Class 5b" in the *2021 Transmission Cost Report*[18].

AEMO added further explanation on the regulatory requirements that must be followed in the cost benefit analysis. This new section details the process to incorporate environmental impacts, and presents detail on the approach to undergrounding power lines.

[18] At https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

5. Discussion of Draft IASR submissions

This section presents material feedback raised by stakeholders in written submissions and verbal feedback from consumer representatives, and AEMO's response to each matter. Feedback is grouped into four main areas:

- Scenario feedback in response to the Draft IASR.
- Scenario feedback in response to the revised scenarios.
- Inputs and assumptions feedback in response to the Draft IASR.
- Inputs and assumptions feedback in response to the *Draft 2021 Transmission Cost Report*.

5.1 Scenario feedback in response to the Draft IASR

5.1.1 Central scenario

AEMO question: Acknowledging that AEMO will consider current committed policy settings within this scenario which meet the criteria outlined in Section 4.1 and clause 5.22.3(b) of the NER, and considering AEMO's best estimates of all key drivers, do you have any feedback on the Central scenario as proposed?

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On net-zero emissions by 2050: **ACF** argued that all scenarios, including Central, need to as a minimum set net zero emissions between 2035 and 2050. **PIAC**, **ENA**, **Havyatt**, **CPD**, and **ACOSS**, also argued that AEMO ought to reflect net-zero emissions by 2050 for the Central scenario, in line with jurisdictional government policies, state targets and ambitions.	In line with this feedback, AEMO has replaced the Central scenario with two alternative scenarios, a 'Steady Progress' and a 'Net Zero 2050' scenario. The Steady Progress scenario assumes Australia makes progress towards achieving net zero emissions outcomes as early as practicable, and no later than the second half of this century. The Net Zero 2050 scenario will assume that Australia transitions towards net zero emissions, achieving this milestone by 2050.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
The **SA Government** argued that given Central needs to fulfill the requirements of the NER, it remains limited in scope – and that a separate additional scenario representing a direction for a net zero emissions by 2050 policy setting should be created. The **NSW Government** requested that AEMO should include a scenario that reflects the NSW's economy-wide net zero emissions objective in future ISPs.	The 'most likely' scenario will be determined later in 2021, with the most up-to-date information available at the time, following the process outlined in AEMO's ISP Methodology.
On aligning Central to (at least) a 2-degree pathway: **ACF** argued that all scenarios, including Central, need to as a minimum align to a 2-degree pathway, recognising efforts to limit temperature increases to 1.5 degrees by 2100. **Infigen** argued that that Central is not fit for purpose, and needs to be redesigned with an Australian emissions trajectory consistent with 1.5 degrees. **Havyatt** argued that Central should be consistent with the IEA SDS, and modelled using RCP 2.6 (aligning to a 2-degree pathway). **NCC** argued that Central should limit temperature rises to below 2-degrees, in line with the Paris Climate Accord. **CPD** also argued that aligning the Central scenario with the Paris Agreement commitment of limiting temperature rises to 2-degrees would be the best practice approach.	Publicly available information highlights the extent of the challenge to achieve the Paris Agreement ambition to limit global temperature rise to 1.5°. In its May 2021 update, the independent Climate Action Tracker[19] considered current policies globally to be on track for temperature rises between 2.1° and 3.9° by 2100[20], while current policy pledges and targets may realise additional action, which if completed may limit temperature rise to as little as 1.9° by 2100. As current policies alone are considered unlikely to achieve the Paris Agreement commitment, AEMO considers it inappropriate for the Steady Progress scenario to assume climate action globally or domestically that is equivalent to the Paris Agreement to limit temperature rise to well below 2° by 2100. The Net Zero 2050 scenario, with a greater initial focus on technology research and development ahead of deployment, is expected to reach net zero emissions in Australia by 2050, but the cumulative global emission abatement in this scenario may be insufficient for temperature rises to be limited in line with the Paris Agreement. This is not to say it won't be achievable in this scenario, but it is not a key feature of the scenario narrative. As such, the scenario narratives around global action (which have flow-on effects on other parameters such as technology cost reductions) remain aligned in both the Steady Progress and Net Zero 2050 scenarios, and are aligned to RCP4.5, which sees temperature increases of around 2.6°. The scenario collection as a whole considers actions that may limit temperature rises in line with the Paris Agreement ambition. Specifically, the Step Change and Hydrogen Superpower scenarios, and the Strong Electrification sensitivity, adopt stronger global action and include commensurate increases in the pace of decarbonisation in the Australian economy, such that temperature outcomes are consistent with limiting temperature rises to 1.5°- 2° by 2100.
On NEM emissions in Central:	AEMO will apply carbon budgets, determined through the application of multi-sectoral modelling, to identify the emissions outcomes that are reasonable for the NEM, influenced by the

[19] Available at: https://climateactiontracker.org/publications/global-update-climate-summit-momentum/.

[20] Consistent with international practice, temperature changes are referenced to the year 2100.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
The **ACF** argued that all scenarios, including Central, need to as a minimum set zero electricity emissions from around 2030.	assumed limits on economy-wide emissions. With the opportunity for broader carbon offsets from the land-use, land-use change and forestry sectors, emissions offsets may enable non-zero emissions intensity in the electricity, and other, sectors if economic to do so.
On the consideration of policy settings in regard to Central: **ACF** argued that all scenarios, including Central, should as a minimum factor all state and territory commitments on climate and electricity, regardless of whether they are firm commitments, policies, plans, or laws. This would include the QLD, NSW, and TAS net zero emission targets, and SA's 500% renewable energy by 2050 target. They also disagreed with what they interpreted as AEMO's view that legislation should be the bar for inclusion as policy settings. The **ISP Consumer Panel** argued that a key weakness of the Draft IASR was its proposal that any changes in public policies that occur between May 2021 and June 2022 would generally not be taken into account in the ISP's modelling. They proposed a new sensitivity ("Material changes in public policy") based on Central with hypothetical new government policies resulting in much higher investment in VRE, storage, DER and REZs. The **MEU** was not satisfied that AEMO developed the best scenarios, as the Central scenario is based more on legislated decisions rather than clearly stated intentions which have been driving legislated changes, and which will continue to do so. **Climate Council** also argued that Central should model Australia's obligations under international treaties, as required by Clause 5.22.3 of the NER, even if explicit mechanisms don't exist yet for the full policy. Assuming no change in policy is highly unlikely to be the Central scenario. **Infigen** argued that the current design with Central is not consistent with state/territory/peak bodies' net zero policies and argued for the inclusion of NSW's Net Zero Plan. More widely, **Infigen** also argued that the underpinning assumption in Central of no changes in policy beyond current policies does not reflect real-world commercial and financial decision-making and should be dropped. **Havyatt** also agreed, arguing that AEMO's interpretation of the rules constrain it – it should not assume no further detailed policy changes beyond currently legislated targets. **RES** argued that Central should be re-calibrated to be more progressive and go beyond current state/federal policies. This would mean that other scenarios should be re-calibrated relative to that new Central.	AEMO applies the 'public policy clause' (NER 5.22.3(b)) in determining whether a policy is included in scenarios. For a policy to be included in scenarios, it must be sufficiently developed to enable AEMO to identify its impacts on the power system. There are also 5 criteria that indicate government commitment to a policy. AEMO considers policy certainty, scenario narratives and the public policy clause holistically when considering the inclusion of a policy in scenarios, not the legislation of a policy in isolation. Stakeholder feedback provided here has informed the finalisation of scenario narratives and the overall scenario collection, including the Steady Progress and Net Zero 2050 scenarios. AEMO will endeavour to include specific policies that meet this threshold that are able to be incorporated in the draft and final ISPs, given practicalities of when policies are announced. Considering that the scenarios provide alternative scenario parameters that impact the pace of transition, in many instances new policy developments may already be appropriately captured by the scenario range.
Other feedback on Central:	In response to some of this feedback, AEMO has replaced the Central scenario with two alternative scenarios, a 'Steady Progress' and a 'Net Zero 2050' scenario. These scenarios include at a minimum the policies that satisfy the public policy clause (NER 5.22.3(b)), and additional

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
The **ISP Consumer Panel** argued it was not clear to the Panel that the issue of decarbonisation is appropriately dealt with in the Central scenario, and recommended further engagement on this issue. **Climate Council** argued that the role of Central should be made clearer, which may require creating a scenario that contains "stated policies" and another that represents a best estimate of the future of the grid, which does not assume that international emission reductions commitment will not progress beyond the 2030 goal. **Infigen** argued that the Central scenario and the Slow Change scenario should be combined in a "Policy Inaction" scenario. Infigen also argued that risk scenarios are useful, but they should not be built off the current Central scenario. **Havyatt** argued that a net zero by 2050 Central requires addressing the design of the system with no fossil-fuel synchronous generation, with consequent implications for system security and system strength. **TEC/Renew** argued that the Central scenario should be renamed to reflect its likely catastrophic outcome. **Sligar**, on the other hand, argued that the Central scenario provided an acceptable starting point. **ACF** also argued that all scenarios, including Central, must adopt levels of transport electrification consistent with Australia's emission projections 2020; and need to as a minimum recognise international net zero commitments by China, South Korea, Japan, the Biden Administration in the US, as well as existing commitments by the EU and UK. **EA** noted that the NER requires AEMO to develop a most likely scenario, and the AER guidelines require AEMO to consider taking the most probable values for inputs. AEMO has also argued that Central will be populated by best estimates. **EA** then argued that AEMO should consider how this terminology may potentially skew stakeholder views. Labelling the Central scenario as the "most likely" may overplay the probability of it being realised.	scenario parameters (such as achieving economy-wide net zero emissions) are adopted in the Net Zero scenario variant. The collection of scenarios therefore provides a range of futures that enable several purposes to be achieved, as highlighted in this document. Note that no scenario in this collection is as yet defined as 'most likely' – the process to determine this is embedded within the ISP Methodology, and will be concluded at least in time for the Draft ISP's publication. Feedback on the use of terminology is noted. AEMO will endeavour to make it clear in the ISP that "most likely", when applied to a scenario, needs to be considered together with its actual weighting (which will be determined in line with the process outlined in the ISP Methodology).

5.1.2 Sustainable Growth

AEMO questions:

- What, if any, elements of the Sustainable Growth scenario as proposed are not plausible or internally consistent, and how would you suggest they should be altered?

- What approach should be used in determining the timing of coal closures in the Sustainable Growth scenario? If you consider that early retirements should be treated as an exogenous input, should this be applied consistently to all power stations, or should only specific power stations be identified and brought forward?

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On decarbonisation and decentralisation: The **ISP Consumer Panel** argued that this scenario may not reflect sufficiently ambitious decarbonisation and decentralisation trends both domestically and internationally. **Walcha Energy** argued that the ISP needed to contemplate accelerated decarbonisation of industry in the Sustainable Growth scenario, not just the Export Superpower.	The Step Change scenario (formerly Sustainable Growth) is expected to result in net zero emissions earlier than 2050, aligned with global action and technology improvements aligned with a 2-degree pathway (recognising the significant efforts to decarbonise both globally and domestically). AEMO has also introduced a new sensitivity that targets the most ambitious level of decarbonisation across our scenarios (consistent with limiting temperature increases to 1.5 degrees above pre-industrial levels) and is aligned to the drivers in the Hydrogen Superpower, but without the technology cost reductions that are the catalyst for significant NEM-connected hydrogen production.
On hydrogen: **Hydro Tasmania** argued that hydrogen should also be considered in the Sustainable Growth scenario. **TasNetworks** noted the exclusion of grid-connected hydrogen, and argued that this is inconsistent with the ambitions outlined, citing the 2020 World Energy Outlook Sustainable Development scenario as the IEA scenario that most closely reflects AEMO's scenario settings for this scenario, and which includes 50 and 470 Mtoe of global hydrogen production by 2030 and 2050 respectively.	Mass hydrogen deployment is expected to require significant cost reductions to deliver hydrogen at a competitive price relative to other alternatives. The technology cost reductions are most significant in the Hydrogen Superpower scenario, leading to opportunities for exports in that scenario. The Net Zero 2050 and Step Change scenarios will include decreasing costs for hydrogen production, but not to the extent required to establish export opportunities within the NEM. Some domestic applications may be economic given limited alternatives across the scenarios, even without the scale of cost reductions assumed in the Hydrogen Superpower scenario. The overall role for hydrogen for NEM consumers is informed by multi-sectoral modelling in these scenarios.
On growth assumptions: **MMTech** argued that growth assumptions should be adjusted for COVID, and that it can now be assumed world demand impacts could last at least five years. **ACF** also argued for the inclusion of a low growth, high decarbonisation scenario. The **ISP Consumer Panel** argued that Sustainable Growth combined two different set of changes from Central: 1) higher decarbonisation ambitions, DER uptake and electrification; and 2) stronger growth assumptions. They argued there is merit in separating these two, and it is unclear why these two changes should be linked.	AEMO recognises that decarbonisation action is not necessarily going to lead to strong growth assumptions domestically, but may depending on the relative actions of other nations. Growth assumptions in the Step Change scenario (formerly Sustainable Growth) have been revised down to the more 'moderate levels' as per the Steady Progress and Net Zero 2050 scenarios, in line with this feedback. For the 2021-22 scenario collection, AEMO does not consider it necessary to examine low growth and high decarbonisation settings, given the challenging investment environment that would persist if these combined, destabilising the effectiveness of the transition. Scenario collections in future years may examine this possible combination.
Other feedback on Sustainable Growth: **TEC/Renew** argued that this scenario should become the new Central scenario.	The key differences between Step Change (formerly Sustainable Growth) and Hydrogen Superpower are varying degrees of economic growth, emission reduction ambitions (with those in the former lower than in the latter) and hydrogen export assumptions. The assumed technological cost

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
Sligar considered this scenario as one of the more likely developments. **Origin** argued that it is unclear how inputs and assumptions differ (in this scenario) from the Export Superpower, and if outcomes would be sufficiently different. AEMO should more clearly differentiate between the two scenarios and explain likely differences in outcomes.	reductions in Hydrogen Superpower affecting hydrogen production are not replicated in the Step Change scenario (to the same extent), leading to a distinct difference in Australia's energy footprint and export opportunities for hydrogen. Alternatively, in other scenarios such as Step Change, any electrolyser hydrogen export facilities are assumed to be developed off-grid away from the NEM, either in Western Australia, Northern Territory, or in electrically-islanded locations such that their development does not influence the needs and benefits of the NEM's future development. The pace of change in global and domestic climate action also leads to a relatively lower (but still strong) carbon budget in the Step Change scenario, with net zero emissions achieved later in line with global temperature outcomes of 2 degrees by 2100 (whereas the Hydrogen Superpower scenario's stronger assumed action leads to temperature outcomes consistent with 1.5 degrees). A new Strong Electrification sensitivity has been introduced that will align with the Hydrogen Superpower scenario but with lower cost improvements for hydrogen production, leading to little to no NEM-connected hydrogen production. This sensitivity will further elucidate the potential impact of hydrogen on the NEM's ongoing development.

5.1.3 Export Superpower

AEMO questions:

- What, if any, elements of the Export Superpower scenario as proposed are not plausible or internally consistent, and how would you suggest they be altered?
- Do you think the uptake of EVs (based on batteries) is likely to be affected significantly by competition with hydrogen-powered vehicles?
- Should this scenario assume that some industries are contracting, for example, coal mining and gas exports?

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On its likelihood and plausibility: **EA's** observation on scenario likelihoods is that Export Superpower is likely to have the lowest probability, however, is still an important scenario and worth exploring. That said, EA would be concerned if creating and assessing more speculative scenarios inadvertently affects the selection of ODPs and actionable projects and gives rise to AEMO recommending certain outcomes and actionable projects on this basis. **Sligar** supports that hydrogen should only be modelled in the Export Superpower scenario.	AEMO acknowledges that the scenario reflects one of many possible futures that may occur even if a global market for hydrogen develops, and expects this will be reflected in the scenario weighting which will be developed later in 2021 in line with the approach provided in the ISP Methodology.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
ECA supports high DER growth in the Export Superpower scenario. The **ISP Consumer Panel** suggested that the level, transparency, and robustness of information meant that little weight should be applied to this scenario. **Sligar** argued this scenario is unlikely unless a South East Asian consortium invests strongly. **Infigen** argued that Export Superpower also has limited insights: Hydrogen production for exports may not be grid connected, and lower EV uptake will reduce the strain on the grid. Higher rates of electrification would help assess the infrastructure needed. **Origin**, **ElectraNet** and **AGIG** supported the inclusion of the hydrogen scenario.	
On decarbonisation: Regarding the assumption that gas distribution networks would transition to 100% hydrogen by 2045 in this scenario, **ENA** argued that it is unclear why as a result the scenario would bring the 2050 net-zero emissions target, which all Australian States and Territories have signed up to, forward by an additional five years. Also **ENA** states the need to consider pathways to transition distribution networks, and notes replacing gas with hydrogen could deliver decarbonisation goals without additional electrification. **ENA** requested clarification on whether net-zero 2040 target is met by offsets of natural gas, and drivers for switching to Hydrogen if met by LULUCF offset. **ENA** also suggested the scenario should either reduce the climate ambition to the Sustainable Growth scenario or increase Sustainable Growth to align with RCP 1.9.	The Net Zero 2050 scenario assumes emission reductions such that the net zero target will be met by 2050. The Hydrogen Superpower scenario is designed to explore the effects of more rapid and ambitious emission reduction global narratives, potentially driven by the need to achieve lower global temperature outcomes, and as a result it is expected that economy-wide net zero emissions will be met earlier than 2050. The level of emissions in the electricity sector in this scenario is informed by the multi-sectoral modelling that AEMO commissioned, and considers the potential switch from natural gas towards hydrogen consumption and other low or zero emissions alternatives.
On Hydrogen demand and production locations: **Energy Estate** argued that the rapid growth of hydrogen would not only focus on export opportunities but also domestically. Transmission costs in this scenario should therefore not only focus on candidate ports but also areas of the NEM where there are existing or potential domestic industries which are major hydrogen users – such as the Queensland Nitrates plant at Noura in Central Queensland. **Havyatt** argued that treatment of hydrogen should be consistent with the Government's hydrogen strategy – which says growth will be domestically led. **Australian Gas Infrastructure Group** mentioned the Export Superpower scenario should consider that some industries are contracting for hydrogen given that this is what is currently occurring. E.g. AGIG have recently signed an agreement with BOC Ltd to install tube trailer refilling infrastructure at the Hyp SA plant. BOC plans to supply industrial customers in Whyalla and Adelaide with hydrogen output from HyP SA.	The Hydrogen Superpower scenario includes increased domestic hydrogen use across transport, industrial process, manufacturing, and the residential and commercial sectors. This scenario's inclusion of a growing export sector is unique to the scenario, and leads to the majority of hydrogen production over the period. As a result, hydrogen production is expected to be concentrated around ports in this scenario, as producers aim to minimise the cost of transporting hydrogen, however domestic hydrogen production locations are also expected, in quantities appropriate for those loads. This domestic consumption may be for a number of purposes, including green steel, ammonia replacement, transportation, and other alternative purposes. The actual production of electricity to supply the electrolysers will be optimised by the detailed long-term supply model from the full range of options available. Other scenarios may have the potential for domestic production, but this scenario specifically envisions significant NEM-connected production aimed at an export market. The domestic hydrogen forecast is an outcome of the multi-sectoral modelling developed for the final IASR. Across all scenarios, where hydrogen is modelled as being produced by electrolysers, AEMO assumes the use of

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
Walcha Energy agreed with the inclusion of this scenario and suggested this future is already eventuating. It noted that it is likely hydrogen will be taken up by the mining and transport sectors, and noted the scenarios should be re-framed, to embrace domestic renewable energy use in other sectors. It suggested a name change to Renewable Energy Superpower which encompass domestic industry, transport and other sectors powered by renewables as well as an export boom to replace coal exports and more. This would be driven by an acceleration of technology enhancement and global trends in energy generation costs, leading to fossil fuel generation being uncompetitive and rapidly displaced in Australia due to our excellent renewable resources. **ACF** argued that in the Export Superpower scenario, hydrogen exports are not the only option to Australia becoming a renewable export superpower. WWF Australia has also identified six types of opportunities, including solar or renewable powered products and commodities such as green steel, aluminium, advanced manufacturing and refining other metals. MUA supported the proposal to add a land-use penalty factor if REZ resource limits are allowed to increase. MUA also argued that the Export Superpower proposal to build transmission from inland REZs to ports further supports the rationale for offshore renewable energy resources. ENA suggested the scenario should consider a proportion of grid connected electricity that will be used to produce hydrogen for the domestic market, given grid-connected renewable electricity will be used for hydrogen consumption.	grid-connected PEM electrolysers. Where hydrogen is produced by other means, this is not expected to impact the electricity system, but may be considered in other reports, such as the GSOO. In the Slow Change and Steady Progress scenarios, some uptake of hydrogen for transport purposes is forecast. It is assumed that this will be produced by steam methane reforming (SMR) facilities, or at remote off-grid electrolyser facilities as needed. This is consistent with the trend of technology adoption where the slower decarbonisation scenarios adopted more SMR development. AEMO agrees that the modelling of offshore wind should be expanded in the Hydrogen Superpower scenario (and in all scenarios). In response to submissions, AEMO has added Offshore Wind Zones (OWZs) in locations where offshore wind projects are being investigated.

5.1.4 Slow Growth

AEMO questions:

- What, if any, elements of the Slow Growth scenario as proposed are not plausible or internally consistent, and how would you suggest they should be altered?
- Do you support AEMO's proposal to adjust the level of distributed PV towards a central outlook in this scenario to provide a broader range of possible minimum demand levels for assessment across scenarios?
- Do you believe that the Slow Growth scenario should allow for the extension of generator retirements beyond their expected closure years if economic to do so? If so, what purpose does this achieve?

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On its likelihood and plausibility: **Infigen** considered that the Slow Growth scenario appears highly unlikely and suggested it could be combined with Central in a new "Policy Inaction" scenario. **MMTech** considered that the most likely outcome is that the Slow Growth criteria would apply for the first half of the 2022 ISP period, with Sustained Growth over the second half. **Sligar** considered this scenario one of the most likely developments. **Walcha Energy** noted that stagnation of battery investments is extremely unlikely and supports the proposal to adjust the level of distributed PV towards a Central outlook. It supported not allowing for the extension of generator retirements beyond expected closure, as economic factors will preclude this from happening. **ACF** argued that low decarbonisation (as presented in this scenario) is implausible, given state and territory governments leading emission reductions. Decarbonisation being less of a priority is also implausible, given the focus on green economic recovery measures.	AEMO's approach, as outlined in the Draft IASR, is for retirements in all scenarios, including the Slow Change scenario, to be in line with expected closure years, or earlier if economic to do so. To ensure a plausible spread of potential future developments, this scenario aims to instead explore a world with slower decarbonisation, lower levels of both economic and population growth, and earlier industrial load closures. This does not preclude decarbonisation, but rather the degree of coordinated action is limited to the public policy settings, and limited sectoral impacts are expected. Economy-wide decarbonisation is not forced in this scenario. As outlined in the other scenarios, this scenario complements the inclusion of three scenarios that meet net zero by (at least) 2050.
Other feedback on Slow Growth: **Hydro Tasmania** suggested AEMO ought to reconsider Slow Growth to include government intervention that would support major industrials and prevent operational demand from falling to the levels assumed in this scenario.	This scenario aims to explore the potential impact of low growth (and its corresponding impact on operational demand) as well as declining minimum demands. Assuming government intervention would prevent this scenario from delivering some of these insights and exploring possible, if not necessarily likely, futures.

5.1.5 Diversified Technology

AEMO questions:

- What, if any, elements of the Diversified Technology scenario as proposed are not plausible or internally consistent, and how would you suggest they be altered?
- If the scenario as specified is not considered to be useful in assessing the costs, benefits and/or need for investment in the NEM or eastern and south-eastern gas systems, are there adjustments that could be applied which would increase the utility of the scenario, while exploring similar risks and opportunities?

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On its inclusion: **ACF** argued that this scenario should be eliminated, given the implausibility of a number of assumptions: • Affordable prices and secure supplies of gas. The most economic and accessible gas is exported as LNG, and further gas expansion will rely increasingly on unconventional gas, which is more expensive. • Higher global investment or uptake of CCS in the power sector. • More limited wind, solar and battery cost reductions. These are largely driven by global factors, and the global push for decarbonisation is supported by net zero policy commitments by Japan, China, South Korea the EU, and the US under the Biden administration. • Lower levels of distributed PV **ACF** also argued that a gas-fired recovery is also ill-advised, given the pace of dangerous climate change and better economic and job prospects of alternatives. It argues AEMO found in its 2020 ISP that gas cannot compete with VRE plus storage unless prices remain at a price range the industry has rejected. The **ISP Consumer Panel** supported the inclusion of this scenario as a way to test the impact of lower gas prices but was not convinced that it was internally consistent. It remained useful as a gas price sensitivity. **Origin** considered it unclear if this scenario is internally consistent and plausible enough, given inputs and assumptions. If the scenario could not be made internally consistent, they argued AEMO could capture this through sensitivities on gas prices or where decarbonisation occurs through low-emission technologies. **PIAC** also opposed the inclusion of this scenario, which they considered did not meet AEMO's standards for inclusion and is a risk to AEMO's credibility and not in the long-term impact of consumers. **Infigen** argued that this scenario would provide limited insights on the operation of the grid, though it would illustrate the impact of non-conventional dispatchable resources. **Walcha Energy** argued that the chances of a gas-led recovery are unlikely, due to the reduction of electricity prices and high gas prices. While gas will have a temporary role in the transition, this will come to an end in most locations with sufficient PHES and battery installations. They also argued that the need to understand whether low gas prices in the next decade increase the risk of over-investment in transmission is unrealistic. This scenario should be replaced with a Priority REZ scenario based on State ambitions and plans.	AEMO has considered the range of feedback from stakeholders on the internal consistency and the inclusion of Diversified Technology and has replaced this scenario with a low gas price sensitivity, to be applied onto one or more scenarios.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
TEC/Renew argued that the scenario should be deleted, or at a minimum be rewritten to be consistent with (at a global level) RCP4.5 rather than RCP2.6. **QEUN** argued that this scenario is useful and should be retained. MEU also supported retaining this scenario. **Ai Group** argued that it should be split in two, one on the impacts of gas, and another on the impacts of different technologies. **ACOSS** argued for the removal of this scenario, and for increased gas production and lower DER to be examined separately.	
On its alignment to SSP scenarios / RCP targets/ IEA scenarios: **MUA** argued that this scenario is very different from the SSP1 scenario AEMO suggests it is linked to, and it disagrees on how it would have the same emission outcome as Sustainable Growth. **Climate Council** argued that references to a global goal of RCP2.6 in this scenario needed to be removed, as Australia will not be able to free-ride on the decarbonisation efforts of other countries. RCP2.6 will require decisive and concerted effort from Australia. **Hydro Tasmania** argued that this scenario should align with the IEA's Sustainable Development Scenario (SDS), as currently it diverges considerably. **Havyatt** argued that this scenario is not consistent with the IEA's SDS, and should instead be reclassified as STEPS, and consistent with RCP4.5 throughout.	After consideration of stakeholder feedback, the Diversified Technology has been modified into a low gas price sensitivity to be applied onto other scenarios. This addresses stakeholder concerns regarding the alignment of the scenario to other scenarios/RCP targets.
On its alignment to the CSIRO's Diversified Technology: **MUA** found its name confusing, as it is the same as the CISRO's which is a different scenario. It argued its name should reflect it revolving around a low gas price. **Climate Council** also found that the scenario does not align with the CSIRO's Diversified Technology, and mislabelling is likely to mislead stakeholders. The CSIRO assumes a carbon price and Australia acting in line with RCP2.6. They argued AEMO should not obfuscate what the scenario is and should restore the previous 'Gas-led recovery' name, or to something else entirely.	After consideration of stakeholder feedback (including on naming and the potential for confusion), the Diversified Technology has been modified into a low gas price sensitivity to be applied onto other scenarios.
On gas prices and CCS assumptions in this scenario: **Climate Council** argued that AEMO should consider alternative means to model gas prices that factor the effect of price volatility, and should also assume and transparently disclose a specific and realistic mechanism to reduce the price of gas, as the type of mechanisms will distort the market in different ways.	AEMO has considered stakeholder feedback regarding the consideration of gas price and CCS assumptions – the new low gas price sensitivity will not retain the CCS aspect of the Diversified Technology scenario.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
Origin argued that based on cost assumptions, it is likely that decarbonisation would still occur through solar with storage rather than CCS, and it is therefore not clear that there can be outcomes where there are higher levels of CCS / lower levels of VRE. **MMTech** argued that federal government intervention has not to date been reflected in lower contract prices, with current prices well in excess of $4/GJ. It also argued that CCS is very expensive, and only viable if using already developed voids like from oil and gas extraction. **PIAC** argued that the assumption that CCS could become economical and widely applicable posed a risk to the ISP's credibility. It suggested that if AEMO persisted with the scenario, it also models a risk sensitivity where CCS technology does not become economically viable after 2030.	
Other feedback on Diversified Technology: **Sligar** argued that this scenario would not come to pass unless Victoria, which has presumed low-cost gas, decided to develop it, and would simplify the eventual power transition for AEMO.	AEMO notes this feedback.

5.1.6 All scenarios

AEMO questions:

- What are the key sectoral uncertainties (if any) that are not adequately explored in the collection of scenarios proposed?
- Do you consider that the collection of scenarios adequately considers the breadth of possible futures that are likely to impact energy supply and demand in the NEM, and are suitable for exploring risks of over- and under-investment? If not, what additional scenarios would better achieve these objectives?
- What scenarios in the proposed collection, if any, do you think should be removed? If any, please indicate why – is it because the scenario is not plausible, or because it does not achieve the primary purpose of exploring major uncertainties and risks of over- and under-investment?

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
Additional scenarios/ sensitivities: **PIAC** considered that an additional scenario that models a trajectory of zero emissions from electricity in 2035 or 2040 would be essential, informative, and improve the credibility of the outputs. **PIAC** also recommended considering modelling high electricity demand and lower gas demand scenarios, as more homes opt for electrification. **Infigen** argued that a new Step Change scenario is necessary, with a 1.5 degree trajectory, zero electricity emissions by 2035, economy-wide reductions of emissions by 60% by 2030 (consistent	AEMO notes and welcomes stakeholder feedback on additional scenarios and sensitivities. The inclusion of the Net Zero 2050 scenario, as well as the scale of decarbonisation within the Step Change and Hydrogen Superpower scenarios, in AEMO's view, reflects the intended extensions proposed by stakeholders. In addition, the new Strong Electrification sensitivity will explore decarbonisation settings of Hydrogen Superpower, without the cost reductions of hydrogen production available to enable material hydrogen penetration.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
with the most ambitious EU policy currently proposed), and electrification of other sectors (with corresponding demand impacts). **Infigen** also argued that AEMO should be future focused, and work with the CSIRO and CWA to identify possible but unlikely changes and possible but unlikely timelines – considering and modelling true "bookend cases", such as: • What would electricity look like under a zero-emissions economy? • What would be the impact on the Victorian grid of the conversion of all natural gas appliances to either electricity or hydrogen? • If Australia adopted a zero electricity emissions sector by 2035, as proposed by President Biden, what would be required to achieve that? • What would a saturated rooftop PV uptake scenario look like? • What would be the impact of a significant battery technology breakthrough that immediately reduces costs? **Infigen** also argued that AEMO needs to conduct detailed power system modelling of all scenarios, but in particular their suggested new Step Change, to understand how the grid would operate in a zero emissions world. The **ISP Consumer Panel** suggested a Decentralised future scenario, driven by reduced DER costs and new government policies. It argued that all of AEMO's scenarios envisage a future with high levels of investment in large-scale generation and interconnection. They propose a scenario with high levels of DER penetration as an alternative (rather than in addition to). The **ISP Consumer Panel** also proposed a new sensitivity on transmission costs given the risk that they materially exceed the forecast costs used by AEMO. Delta proposed a similar scenario with materially higher transmission costs. **MUA** suggested a sensitivity for higher level of development of offshore wind to be modelled. The Climate Council also suggested a sensitivity that factors in consistent and stable policy support for offshore wind. **Climate Council** also argued that there is merit in modelling a scenario that prioritised diversity of supply, and increased redundancy. **Energy Australia** suggested that reductions in demand (e.g. load closures) should be tested with respect to the ODP as sensitivities. **ACF** argued for a new scenario where Snowy 2.0 is not delivered, or not delivered on schedule. Hydro Tasmania also suggested a delayed Snowy 2.0 and interconnector delay sensitivity.	AEMO has also noted other initial sensitivities, to explore key variables such as gas prices, DER investment, transmission costs and discount rates. These have been directly informed by stakeholder feedback. The ISP Methodology provides additional clarity on the method by which transmission costs will be explored through CBA analysis. Other technology-specific assumptions such as offshore wind is to some extent explored through the cost trajectories which differ between scenarios. AEMO has added Offshore Wind Zones (OWZs) in locations where offshore wind projects are being investigated. Load closures are largely explored through the Slow Change scenario, but may also inform sensitivity analysis. Delays on Snowy 2.0 and associated infrastructure have not been included as they are considered unlikely to influence the costs and benefits of potential actionable projects in the next ISP.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
ACOSS argued AEMO should include a more ambitious scenario that limits global warming to 1.5 degrees.	
On assumptions across scenarios: **IEEFA** noted there is a higher risk of under-estimating assumptions of VRE and DER in scenarios, than of over-estimating. **EQ** questioned the "logical consistency" of PV/EV and battery uptake for each scenario. **EA** asked AEMO to reconsider the treatment of TRET, treating it as less certain than other state-based renewable energy targets. They argued that recognition of TRET as a confirmed policy should be dependent on legislation as well as associated funding commitments (given the Tasmanian Government reservations about funding Marinus Link). **ECA** argued that the impact of COVID-19 and bushfires, as well as assumptions around DER, require more work. Furthermore, the IASR does not appear to consider the longer-term changes in energy consumers' social and business practices. Scenarios should also explore ways in which Australians think about energy due to the impacts of bushfires and COVID-19. **ECA** also questioned whether AEMO should be applying anything other than high rates of PV and DER settings across scenarios, given evidence of community acceptance of these technologies. **AGIG** argued that all scenarios should consider the addition of hydrogen, as there are broader opportunities for hydrogen in the domestic market. **Sligar** argued that state policies should be included across all settings, and international policy settings should be noted – limitations on coal and LNG exports will make these significantly cheaper within Australia. **ACF** argued that all scenarios need to, as a minimum: • Set net zero emissions between 2035 and 2050. • Align to a 2-degree pathway, recognising efforts to limit temperature increases to 1.5 degrees by 2100. • Set zero electricity emissions from around 2030. • Factor all state and territory commitments on climate and electricity, regardless of whether they are firm commitments, policies, plans, or laws. This would include the QLD, NSW, and TAS net zero emission targets, and SA's 500% renewable energy by 2050 target. • Adopt levels of transport electrification consistent with Australia's emission projections 2020. • Recognise international net zero commitments by China, South Korea, Japan, the Biden Administration in the US, as well as existing commitments by the EU and UK.	AEMO notes and welcomes this feedback. The level of DER uptake has been aligned to scenario narratives, and has been informed by discussions in a number of stakeholder workshops on scenario design, and the impact of higher DER uptake will be explored through a further sensitivity. As a legislated policy that is sufficiently developed to enable AEMO to identify the impacts of it on the power system, TRET will be included across all scenarios in a similar fashion to other public policy settings. However, one of AEMO's event-driven scenarios will include the removal of both Marinus Link and the TRET from relevant scenarios (being those that are found to sufficiently influence the choice of the ODP). The objective of this assessment is two-fold: • First, it will provide an indication of what additional or alternative investments, investment deferrals, or other changes in investment timing might be required if cost recovery arrangements for Marinus Link were not able to be resolved. • Second, these sensitivities will require the modelling of counterfactuals which do not have the TRET. The net market benefits of Marinus Link through comparison of counterfactuals both with and without the TRET provides an indication of the sensitivity of the project to the inclusion of the TRET policy, which will be considered in the determination of the ODP. Other scenarios will have the potential for some domestic hydrogen consumption, but production costs are not expected to decline sufficiently to introduce material hydrogen exports. Regarding ACF's suggestion to increase the level of ambition to at least the same level across all scenarios, and ECA's suggestion to only apply high rates of PV and DER, AEMO notes that not all scenarios have the same purpose; and as detailed in the IASR, one of AEMO's key considerations when developing scenarios is that the scenarios cover sufficient breadth of possible futures and are sufficiently distinct from each other so that they achieve a particular purpose. AEMO considers restricting scenarios in the ways described would limit the achievement of this requirement.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On risk scenarios: **Delta** requested AEMO to release the full modelling details and results for the early closure risk scenarios, including assumptions and, in particular, details of the impact on wholesale prices and on the remaining coal fired generators within each jurisdiction. **Walcha** Energy argued that the Central with early northern NSW coal closure is the most likely and important risk scenario, while Marinus Link funding not resolved is the least likely. The least important scenario would be Sustainable Growth with central DER uptake. **Sligar** argued that NSW coal closure has the highest importance out of all possible risks and Victorian coal closure the highest likelihood. Adequate investment is considered a far greater overall risk than any of the above. **TasNetworks** suggested that the proposed scenario on Marinus Link not going ahead be removed, given the increase in funding certainty. **Hydro Tasmania** questioned the validity of the sensitivity that would examine Marinus Funding arrangements not resolved, given the ongoing work by various levels of governments as well as market bodies, to establish appropriate cost-allocation methodologies for major transmission investment processes. **EA** suggested that AEMO's approach to Marinus Link warrants closer attention. It is not clear whether the sensitivity means funding arrangements are delayed from optimal timing or are never resolved.	AEMO will consider the method for considering the influence of potential events across the scenario and sensitivity collection endogenously through the ISP. As identified in Section 4, AEMO will examine the possibility that funding arrangements are not resolved for the Marinus Link project through the event-driven scenario and approach outlined in the above, and in the IASR (Section 2.2).
On missing inputs **Infigen** argued that the rate of electrification of other sectors (and in particular gas appliances) is a missing input in the scenarios.	The rate of electrification of other sectors has been informed by outputs from the multi-sectoral modelling commissioned by AEMO.
On missing scenario dimensions: **ECA** argues that AEMO should develop new scenario dimensions in future IASR processes around issues like trust, that influence the decisions consumers make about energy and how they source it. **Sligar** argued that the scenario principles do not identify the two emerging markets, one for power and other for system stability, and the competition between these two for investment	AEMO notes the feedback and will consider actions for future forecasting and planning scenarios.
Other scenario observations:	The impacts of COVID-19 in the short-term are incorporated in the development of energy forecasts within each scenario.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
Origin was broadly supportive of the more comprehensive approach that AEMO has taken in developing the 2021 draft scenarios, which they argue represent a broader range of plausible futures given what we know today. **ECA** argued that the AEMO should make use of the Australian Bureau of Statistics data of how COVID-19 is impacting the Australian community. **ECA** also argued that AEMO should test the sensitivity of the five scenarios to different levels of consumer and community trust in the energy sector and support for decarbonisation policy. **Hydro Tasmania** argued that IASR should include probability weightings for each scenario. **Havyatt** argued that scenario weightings are arguably a foolish concept, as the statistical likelihood of the actual outcome being the same as any of the defined scenarios is zero. **QEUN** argued that AEMO must consider the impact of possible reluctance from the private sector in investing in new large-scale VRE. **Sligar** argued that scenarios should not be aligned with international scenarios, as it is difficult enough to cope with federal/state scenario aspirations. AEMO should only do so if the federal government aligns with one particular international scenario. This also applies to state-based emission targets until legislated. **MEU** was not satisfied AEMO had developed the best scenarios, as they do not reflect the intention of state governments to reach net zero emissions by 2050. The MEU suggested that proposed event-driven scenarios should be tested against all scenarios, rather than applied only to the central scenario which could introduce distortions in the scenario weights.	As described in this document, AEMO has adjusted its scenario collection to incorporate the Net Zero 2050 scenario, as well as sensitivity refinement. AEMO notes that further discussion on AEMO's proposed approach to determine scenario weights was provided in the Draft Methodology. Sensitivities will be tested, but are not assigned scenario weights. The collection of scenario weights will be developed and informed by stakeholder input later in 2021, considering the scenario and event-driven scenario collection.

5.1.7 Approach to decarbonisation and emissions

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On the determination of carbon budgets: **Climate Council** argued that AEMO should confirm the implementation of SSPs has been conducted correctly, by incorporating external advice from recognised experts in the field. The **ISP Consumer Panel** argued that the IASR should be aligned with 2050 modelling timeframes, given it is an important year in the current policy transition of every NEM jurisdiction. Research studies and datasets on decarbonisation and climate change impacts should be investigated and	AEMO welcomed and considered all stakeholder feedback on the determination of the carbon budgets. As a result, it has commissioned multi-sectoral modelling to inform the NEM carbon budget consistent with the range of SSP/RCP pairings detailed for each scenario; as well as the level of electrification that is consistent with each level of emission reduction ambition.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
AEMO should seek peer review from an independent, apolitical expert to validate the facts and trends that inform its assumptions. **Infigen** suggested that a carbon budget should be developed by working with external experts. **TasNetworks** requested clarification on the computation of carbon budgets across scenarios, suggesting they need to be adjusted downwards. **PIAC** argued that AEMO needs to ensure that emission targets are consistent with Australia doing its fair share as part of achieving the assumed temperature increase. **ACF** argued that given state and territory commitments, carbon budgets similar to the Export Superpower and ClimateWorks 1.5 degrees should be the case across all scenarios. **EA** considered the coverage of policy impacts to be well researched, and the scenario alignment to SSPs, global temperatures and IEA scenarios to be appropriate. AEMO's updating of these inputs with AR6 updated climate assessments should be subject to BOM guidance on the most representative models.	Details of the multi-sectoral modelling approach and outputs will be included in the final IASR release. The IASR will be aligned with 2050 modelling timeframes.
On the allocation of emissions to the NEM **ACF**, **Walcha Energy**, **Infigen**, **NCC**, **Hydro Tasmania**, and **ACOSS** argued that the rate of decarbonisation is expected to be faster in the electricity sector than across other sectors/economy-wide and assumed pro-rata emission reductions in electricity are not appropriate. **Walcha** Energy also argued that mining of coal and extraction of gas, to the extent they are applied to domestic power generation, should be incorporated into electricity emissions. The **ISP Consumer Panel** also argued that for two scenarios (Sustainable Growth and Export Superpower) AEMO should consider whether it would be more realistic to assume an increased share of the emissions reduction budget allocated to the electricity sector.	As discussed above, as a result of stakeholder feedback, AEMO has commissioned multi-sectoral modelling to inform the level of emissions at a NEM level that are consistent with a variety of domestic carbon budgets. Given this modelling will encompass all Australian emissions, emissions captured by mining and coal extraction are considered best captured within those sectors.
On state-level emission targets and policies: **EA** argued that legislated state-level interim emission reduction targets should be integrated once announced, and suggested that policies that meet the criteria for inclusion across all scenarios should continue to be incorporated for the duration of 2021, and not halted as at May 2021 as AEMO suggested. **ACF** also argued that scenarios should include commitments to transition bus fleets to electric buses, such as the NSW Government replacing its 8,000 bus fleet with battery EVs (BEVs) by 2030.	AEMO understands the feedback provided and will endeavour to include policies that meet the NER requirements for public policy into both the draft and final ISP. Practical limitations may mean that when modelling, some policy settings have not yet progressed sufficiently to satisfy the requirements of the NER on treatment of public policy in the ISP, and, accordingly, will not be able to be incorporated completely for the Draft ISP. These may be revisited for the final ISP if policy developments occur in a timely manner. AEMO's projections of electric and alternative-fuelled vehicles consider an appropriately wide range of potential futures for electrified transportation options, including electric buses. Given that the project to transition the New South Wales bus fleet is in its infancy, AEMO considers that capturing this within the scenario spread of outcomes for vehicles is appropriate.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On assumptions around (land-use, land-use change and forestry) LULUCF / other sectoral emissions: **ACF** argued that a zero emission targets needs to be set for most sectors (including electricity) and that carbon forestry, LULUCF, or offsets should not be relied upon to achieve zero emissions. **ENA** suggested it is unreasonable to use the LULUCF sector to balance emissions leftover in energy sectors, as it has offsetting limitations. **Havyatt** agreed that LULUCF negative emissions should not balance energy system emissions, and AEMO should assume that any credits available from other sectors (e.g. land-use changes) will be offsetting other emissions. The **ISP Consumer Panel** also questioned the approach that allows LULUCF emissions to balance leftover emissions from energy by acting as a carbon sink. As a minimum, they argued AEMO should include an estimate of cost for offsets from other parts of the economy to test the efficiency of this approach.	As discussed above, as a result of stakeholder feedback, AEMO has commissioned multi-sectoral modelling to inform the level of emissions at a NEM level that are consistent with a variety of domestic carbon budgets. This multi-sectoral modelling does also consider, and deploy, emission abatement from the LULUCF sector. This is an endogenous component in the multi-sectoral modelling, and details of the approach and outputs is included in the 2021 IASR.
Other feedback on decarbonisation and emissions: **CPD** analysis concluded that directors of public sector bodies and authorities have duties to consider climate risk at least as stringent as duties of private sector counterparts. Legal opinions commissioned by CPD have highlighted that not properly managing climate risk could breach directors' legal duty of due care and diligence. **Havyatt** argued that the GSOO also seems inconsistent with the net zero target for all jurisdictions, with very little substitution of gas in the period out to 2041. **Walcha Energy** argued that AEMO should anticipate and incorporate updates to the current IEA scenarios reflecting increased ambition (particularly in the US and Europe). It also noted that state based VRE targets and corporate renewable energy procurement are larger drivers of retirements and investments, rather than growth in the economy. The **SA Government** argued that there is insufficient detail in the draft IASR that clearly articulates whether an alignment of the draft IASR scenarios to the IEA's 2020 World Energy Outlook scenarios will result in net zero emissions by 2050. **ACF** noted that the IEA will release a comprehensive roadmap for the energy sector to reach net zero emissions by 2050 in May 2021. **ACF** also noted that the text on page 32 of the Draft IASR ("The Federal Government has set a target to reduce greenhouse gas emissions economy-wide to 26% below 2005 levels by 2030") should be updated to include the full 26-28% target.	AEMO notes and welcomes this feedback. The scenarios deployed for the 2021 GSOO are, in most part, consistent with the 2020 ISP scenario collection, and these new 2021-22 scenarios will apply in future publications. AEMO considers that the breadth of decarbonisation ambition across the scenario collection sufficiently captures the potential range of futures, including net zero achievement on or before 2050 economy-wide across multiple scenarios. AEMO notes the commentary regarding the domestic emissions projections as well as domestic and international pathways, and has considered the available data ahead of finalisation of the 2021 IASR. AEMO's inputs and assumptions are informed by the latest National Greenhouse Gas Inventory (2019), as well as by the latest IEA scenarios. References to the 2030 target and projections will be amended when appropriate based on the latest estimates. As outlined in Section 2.1 of the IASR, multiple scenarios in the collection consider economy-wide net zero emissions on or before 2050, with the Slow Change and Steady Progress scenarios being the only scenarios that consider achievement of this objective later than 2050.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
It also argued that the following statement on page 42 of the Draft IASR is incorrect ("The latest government emissions projections estimate that Australia will overachieve its 2030 target"), and that Australia's emission projections 2020 anticipate Australia will fall short of its 2030 target, achieving only 22% emission reductions below 2005 levels.	

5.2 Scenario feedback in response to the revised scenarios

5.2.1 Steady Progress (formerly Current Trajectory) and Net Zero 2050 scenarios

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On replacing the Central Scenario: **Sligar** agreed that Current Trajectory should be based on existing legislation, and with the decision to have an additional Central scenario with a goal of net zero by 2050. **PIAC** welcomed the decision to split the Central scenario to better reflect state-level emission reduction commitments. **AGL** supported the decision to replace Central with two scenarios, given all states and territories have committed to net zero by (at least) 2050, and recent Federal Government discussions on adopting a similar target. **Energy Australia** supported AEMO's proposal to split Central into two, as all states and territories (and many market participants) have some form of net zero target or plan. **Infigen** urged AEMO to make the most likely scenario representative of Australia's commitments under the Paris Agreement i.e. net zero well before 2050. **AusNet** Services welcomed the proposed inclusion of the Net Zero 2050 scenario, and determining the Central scenario based on a weighting of Net Zero 2050 and Current Trajectory.	AEMO notes and welcomes the supportive feedback regarding the way that AEMO has replaced the Central scenario with the two additional Steady Progress and Net Zero 2050 scenarios.
On the most likely 'Central' scenario: **Sligar** considered having two scenarios as a reasonable extension. **TasNetworks** supported there being only one Central and considers the most appropriate one to be Net Zero by 2050 as the "most likely" scenario. This is due to strong stakeholder support, with all states and territories having a net zero target and more recent emphasis by the federal	AEMO notes stakeholder feedback supporting the addition of the Net Zero 2050 scenario. AEMO considers that having a spectrum of scenarios that consider different levels of the use of the decarbonisation pillars (energy efficiency, decreasing carbon intensity, fuel switching including electrification, and sequestration) is appropriate, particularly given uncertainty around domestic and international commitments and the timing of achievement of net zero emissions, economy-wide.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
government to reach net zero as soon as possible and preferably by 2050. Most of Australia's major trading partners also have net zero commitments by 2050. **Shell Energy** questioned the need for both Steady Progress and Net Zero 2050 and feels that the Net Zero 2050 scenario adequately reflects the ambitions of respective government and business announcements. Having two Central scenarios may lead to confusion as to what the "central" / "most likely" scenario is and fail to meet the AER's guidelines. **MEU** argued there is a need for a clear central scenario and not an amalgam of two scenarios as most stakeholders base their decisions on the most likely outcome. It was suggested to use the Central – 2050 Net Zero, as it captures the aspirations on emission reduction of the State Governments and industry. The Steady Progress scenario will understate the likely emission reduction. **Origin** argued that having two Central scenarios is confusing and not clear which one is the "most likely". **Hydro Tasmania** strongly recommended to consider the Net Zero 2050 trajectory as the 'sole central scenario'. It also recommended that it would be more appropriate to commence the net zero trajectory earlier than 2030.	AEMO considers that including both the Steady Progress and Net Zero 2050 scenarios (rather than just Net Zero 2050) is most appropriate. The determination of the most likely scenario will form part of the consideration of scenario weights, developed later in 2021, as described in the ISP Methodology.
Other feedback on the Net Zero 2050 scenario: **VBN** argued that the net zero emission target should consider developing a solid bioeconomy, including biomass to energy, biochemical, and biomaterials. It suggested that AEMO should study international cases of success that progress to achieving the zero net GHG emissions target based on the development of a bioeconomy.	AEMO notes that the multi-sectoral modelling does consider the wider energy system, and endeavours to incorporate the potential for bioenergy across sectors other than electricity generation. Details of the approach and outputs will be included in the final IASR release.

5.2.2 Low gas price sensitivity to replace the Diversified Technology scenario

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On removing Diversified Technology: **PIAC** agreed with the decision to remove Diversified Technology. **MEU** supported retaining Diversified Technology as it provides a plausible boundary scenario with government stated ambition on some investments, although it agrees it is unlikely to happen.	AEMO considered that on the balance of feedback across the scenario collection that the conversion of the Diversified Technology scenario to a gas price sensitivity remained the preferred approach.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
Shell Energy considered the Diversified Technology as one worth investigating, and as a useful bookend scenario. Having it as a scenario allows it to focus on new technologies, constraints in the distribution network, and other plausible changes.	
On the new low gas price sensitivity: **PIAC** was concerned that a low gas price sensitivity is unrealistic and risky, as it is not compatible with international climate obligations or ensuring a safe climate. It considered the rationale for its inclusion to be unclear, and that it undermines AEMO's credibility. **AGL** supported the decision to convert Diversified Technology into a sensitivity, as it better reflects the likelihood of low gas prices. **EA** also supported this decision. **Origin** also supported AEMO's proposal to capture this potential future through a low gas price sensitivity instead.	AEMO notes the majority of feedback in favour of examining the impact of lower domestic gas prices on the ODP, and has included it as a sensitivity.

5.2.3 Slow Change

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On potentially combining it with Steady Progress: **TasNetworks** argued for Steady Progress and Slow Change to be amalgamated. The weakness in both scenarios is the retirements at the end of life, as recent announcements suggest that environmental and economic factors will result in early retirements. It welcomes modelling that allows early retirements if a plant becomes uneconomic.	These scenarios serve ultimately different purposes. The Steady Progress scenario will incorporate best drivers, and legislated policies – but will not impose a net zero by 2050 target. On the other hand, Slow Change aims to examine the impact of falling levels of minimum demand coupled with higher levels of penetration of PV, as well as lower levels of operational demand and a slower energy transition longer term. This has been achieved by coupling high levels of distributed PV with lower levels of growth. As outlined in the ISP Methodology, coal retirements will consider both end-of-life and economic drivers in all scenarios.

5.2.4 Hydrogen Superpower

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On domestic hydrogen use: **PIAC** argued that this scenario should not incorporate higher domestic use of hydrogen, as it is unlikely hydrogen will ever play a significant role in the domestic energy grid. **EA** questioned the use of domestic hydrogen in this scenario, and how it might interact with EV and higher DER forecasts.	AEMO is applying a consistent methodology to domestic hydrogen consumption via the multi-sectoral modelling that has been commissioned. This considers the opportunities available to all sectors to achieve the decarbonisation objectives of each scenario, which includes transitioning current energy sources to low or zero-emissions sources, such as hydrogen, as well as other carbon offsetting solutions. Consistent with the narrative of the scenario, the Hydrogen Superpower scenario incorporates the strongest level of technology cost reduction, which influences the scale and timing of domestic as well as export production opportunities. Details of the approach and outputs of the multi-sectoral modelling will be included in the final IASR release.

5.2.5 Sensitivities

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On considering Strong Electrification a scenario: **EA** argued that given plausibility, it may be more appropriate as its own scenario, incorporating limitations on domestic hydrogen as the base, and with Hydrogen Superpower being run off as its sensitivity. **TasNetworks** agreed with this idea, on the basis that the IEA's 'The Future of Hydrogen' report outlined that near-term opportunity for hydrogen is maximising domestic consumption, and gradually enhancing infrastructure for large-scale export. TasNetworks also suggested that it should include hydrogen production in line with the Sustainable Development scenario from the WEO 2020. **Origin** supported considering Strong Electrification as a sensitivity only, because it is otherwise too similar to Step Change to cover as a scenario.	AEMO notes feedback on considering this sensitivity as a scenario, but considers that the scenario collection (including Hydrogen Superpower) appropriately captures the potential breadth of futures. The scale of hydrogen production for domestic purposes across scenarios will be an outcome of the multi-sectoral modelling. Details of the approach and outcomes are included in the 2021 IASR.
On the transmission cost sensitivity: **Shell Energy** considered this to have great benefit, as it is likely to better reflect the realities of the costs of large transmission projects. This sensitivity should use costs at the high end of the estimated range, and potentially 20% above that to reflect uncertain costs.	AEMO understands the importance of understanding the potential impact of transmission costs. As described in the ISP Methodology: • AEMO has developed a new approach to transmission cost estimation that improves transparency and standardises the approach to incorporating risk based on the stage of project

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
	development. This transparent assessment of costs and risks will inform stakeholders on the accuracy and potential cost risks to future projects (see Section 5.4). • In addition, AEMO will leverage take-one-out-at-a-time (TOOT) analysis to inform the sensitivity of actionable projects to increases in capital costs to provide guidance on potential cost ceilings beyond which projects may not be viable.
On Marinus Link: **EA** perceived considerable doubts around funding arrangements, which infers doubts as to whether TRET meets the criteria for inclusion. It then proposed that a more appropriate event-driven scenario would be where funding arrangements are resolved, rather than the opposite.	AEMO notes this feedback, but considers the public policy requirements to have been achieved for the TRET's inclusion. The influence that the Marinus Link project has on the achievement of this policy will be explored in the event-driven scenario, as detailed in Section 4, and in the IASR (Section 2.2).
On other sensitivities: **PIAC** considered it may be useful to apply rapid decarbonisation through DER as a sensitivity on Slow Change, given recent evidence that the COVID economic slowdown did not correspond to a decline in DER. **Shell Energy** recommended a new sensitivity that couples low economic and population growth with high decarbonisation. It also considered the Decentralised Future sensitivity proposed by the Consumer panel is worth including, which should also consider and quantify the level of distribution network investment required.	AEMO notes this feedback. The alternative DER uptake sensitivity will be applied to one or more of our scenarios. It is worth noting that the design of Slow Change implicitly acknowledges the issue raised by PIAC, by coupling high levels of distributed PV with lower levels of growth.
Other feedback on sensitivities: The **ISP Consumer Panel** and **Shell Energy** both considered that AEMO needs to further explain the difference between "scenarios", "sensitivities", and "other risks to be tested", in particular how the latter two will be used in the ISP and by TNSPs in the RIT-T. They note that it seems like moving low gas prices to a sensitivity would prevent TNSPs from placing any weight on it in the RIT-T process.	AEMO has provided detail on the use of scenarios and sensitivities in Section 5 of the ISP Methodology.

5.2.6 Other scenario issues

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On scenario weights: The **ISP Consumer Panel** noted that under the AER ISP Guidelines, AEMO is required to identify a 'most likely' scenario. AEMO needs to start consulting on scenario weights, and identify a 'most likely' scenario as a matter of priority. EA agrees that AEMO should outline its process to designate the most likely scenario, and Shell Energy recommends AEMO commences engagement on determining scenario weights well before the final IASR.	AEMO published more information on the proposed approach to determine weights in the ISP Methodology. Stakeholders supported the approach proposed, and provided views on the make-up of the Delphi Panel[21].
On maintaining scenario consistency through ISPs: The **ISP Consumer Panel** strongly encouraged AEMO to consider the merits of using the same set of scenarios for at least two ISP iterations, which would allow stakeholders to more easily engage in other aspects of the ISP Methodology.	AEMO acknowledges the Consumer Panel feedback. While inputs have been updated in all scenarios, where practicable, AEMO has changed scenario names to align with those used in the 2020 ISP.

5.2.7 Multi-sectoral modelling

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On the decision to use multi-sectoral modelling outputs: **EA** supported the consideration of integrating multi-sector modelling in the ISP, though they do not see any reason to limit its use to some scenarios/sensitivities – being mindful of the risks associated with a broader scope of work and not to let this come at the expense of other high priority refinements. **Hydro Tasmania** also commended the decision to include multi-sectoral modelling for emissions.	AEMO notes and welcomes this feedback, and has prioritised scenarios with the greatest decarbonisation ambition for inclusion in the multi-sectoral modelling.

[21] Details on the Delphi Panel approach to determining scenario weights is described in the ISP methodology, available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
Other feedback on multi-sectoral modelling: **Shell Energy** sought clarification on what AEMO meant when it stated that the Steady Progress scenario will have "limited guidance from multi-sectoral outputs". **TasNetworks** encouraged multi-sectoral emission outcomes to be broadly consistent with other global publications – e.g. WEO 2020 recognises that the power sector will be among the first to decarbonise. **Sligar** argued that to date political actions have affected power generation to a far greater extent than other necessary abatement /more than its fair share. The scenarios should reflect this anomaly together with the impositions on other sectors of the economy. ENA also noted neither coal mining nor gas exports are significant drivers of electricity consumption so there would be minimal impacting of these industries contracting on the ISP, and also requested to clarify the term "electrification" to ensure assumptions are clearly articulated, as this may imply the end of use of gas with electricity.	The Steady Progress scenario will be informed by multi-sectoral modelling over the period to 2030, and in particular the pace of electrification from the transport and other sectors. After 2030 the Steady Progress scenario will limit its consideration of electrification to those actions influenced by public policies included in the scenario. Given that the scenario does not achieve a pre-determined net zero emissions outcome, but rather shows a steady decline in emissions driven by market forces, the scenario will not impose an economy-wide coordinated approach to emissions reduction. Electrification is defined as any energy demand being transferred to electricity. Oil, coal and gas are all notable forms of energy supply that may be able to be replaced with electricity for many, but not all, end uses. Note that conversion to hydrogen, regardless of how the hydrogen is produced, would not be considered to be electrification. Fuel switching is a broader term and previously it has typically referred to gas converting to electricity demand, but fuel switching accounts for any change of energy input, including from one fossil fuel to another (e.g. coal to gas). Note: At around 6.5 TWh of electricity consumption, gas exports are a notable source of electricity demand.

5.2.8 Emissions and government policy

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
On emissions trajectories: **PIAC** considered that the Net Zero 2050 scenario should have a consistent trajectory to 2050 (rather than pivoting after 2030) to better reflect state policies, and should not be tethered to federal 2030 targets Steady Progress. **Shell Energy** considered that it is unclear that a linear trajectory from 2030 to 2050 is the most likely outcome. AEMO should consider other trajectories (such as exponential, or 5 year trajectory paths). **Origin** supported the decarbonisation approach in scenarios. The adoption of distinct scenarios to cover decarbonisation levels and more rapid decarbonisation with hydrogen covers the breath of potential futures.	AEMO notes this feedback. A trajectory that limits emissions to meet (or fall below) the legislated 2030 target is considered appropriate in both the Steady Progress and Net Zero 2050 scenario given current Government policy. State policies facilitating renewable generation development may lead to emissions trajectories that fall well below these limits by 2030. Beyond 2030, these scenarios differ in that the Net Zero 2050 reflects state ambitions of 2050 net zero emissions. The Net Zero 2050 scenario will not apply coordinated objectives economy-wide until a transition point near 2030, allowing time for coordination of sectoral action and technology advances to penetrate public policy. AEMO agrees with Shell Energy's feedback that a linear trajectory is not the most likely pathway for emissions reduction. The Net Zero 2050 scenario applies a more gradual rate of decarbonisation initially, but which increases over time, accounting for decarbonisation actions (such as electrification and sequestration) as modelled through multi-sectoral modelling.

Feedback received	AEMO response (naming convention refers, where relevant, to final scenario names)
	As outlined in the ISP Methodology, the emissions trajectory for the electricity sector from the multi-sectoral modelling will inform the carbon budget approach applied across scenarios in AEMO's ISP modelling.
On government policy: **AGL** argued that legislated targets (for example, the NSW Electricity Infrastructure Roadmap) should be fully reflected in all scenarios, including accounting for any generator closures that may occur due to the policy. **AusNet Services** suggested that the Central scenario should reflect the Victorian Government's policy commitments (with respect to REZ and emissions targets) as the actions of the government suggest a strong commitment to delivering on both their renewable energy and emissions-reduction targets. It also noted that beyond 2030 no VRET is assumed. While consistent with the lack of a legislated target beyond 2030, these are most likely to be added, as these mechanisms are implementation of Victoria's Climate Change Act 2017. The IASR scenarios could reflect the uncertainty over a specific VRET trajectory by factoring various trajectories to reach net-zero emissions for Victorian generation by 2050. **Walcha Energy** argued that state governments are the appropriate bodies to identify priority REZs within each state and plan their progress. AEMO's NEM perspective and national grid requirements are critical inputs to state plans, but the deliverable plans of the states for the development of priority REZ must drive the Central scenario of the ISP.	AEMO notes this feedback and has identified in this document, and in the IASR, that the suggested state policies mentioned are incorporated across all scenarios, as well as other public policies as per NER 5.22.3(b). AEMO's public policy settings will not impose renewable energy target extensions, however the size and location of future VRE development and REZ requirements will be influenced significantly by other drivers (such as cost competitiveness, quality of resources and carbon budgets in those scenarios that apply them).

5.3 Inputs and assumptions feedback in response to the Draft IASR

5.3.1 Public policy settings and emissions

AEMO questions:

- Do you support the approach outlined for the inclusion of government policy across the scenarios?
- Do you have any further views on the individual policies and their application?
- Are there any energy or environmental policies missing that you consider important to include in some or all of the proposed scenarios? Please provide details.

Feedback received	AEMO response
On the inclusion of policies: The **MEU** recommended that the ISP should include other policies such as the Federal Government's decision to provide up to 1,000 MW of gas-fired generation in New South Wales. **EA** also flagged that updates will be required to accommodate developments since the draft IASR such as the Victorian Government's support for energy efficiency, rooftop PV, etc. **ENA** also suggested including policy updates as close as possible to the publication of the final ISP. **Origin** stated that the inclusion of policy should be transparent and that AEMO should explain how policy has affected the modelling outcomes, and where there is uncertainty in the implementation that AEMO should include sensitivities to promote the understanding of these risks. Origin supported the inclusion of a sensitivity on the TRET and recommended AEMO to explore other policies subject to similar risks. **EA** also requested additional clarity on the approach to storage auctions in regions other than New South Wales (where detail was provided as part of the specification of the New South Wales Electricity Infrastructure Roadmap). **Energy Estate** stated that the ISP should take into account renewable energy procurements pursued by governments, their agencies, councils, etc. over and above their renewable energy targets, and that AEMO should also consider the large number of energy users who have now committed to 100% renewable energy or net zero.	AEMO will incorporate the impacts of any policy updates where possible. This will depend on the materiality of the policy, the timing of the policy release, and where the detail provided is sufficient to satisfy the public policy clause (NER 5.22.3(b)). Since the draft IASR, the impact of policies such as those announced by the Victorian Government have been considered in the development of updated demand projections. The implementation of government announcements regarding 1000 MW of gas fired generation is implemented considering whether specific projects meet the criteria for being committed or anticipated. The inclusion of projects based on commitment status in the July 2021 Generation Information release ensures as much up-to-date development advice is incorporated as possible. In that release, the recently announced Kurri Kurri 750 MW gas fired peaking plant is considered committed. The ISP will not detail the impacts of the inclusion of policy by comparing outcomes against alternative future worlds absent of the policy, however where there is significant uncertainty in the implementation, AEMO will endeavour to explore sensitivities to understand that robustness of actionable projects to these uncertainties. One such sensitivity already identified is in relation to Queensland Government's recently announced QREZ policy. Generation and storage developments in the Northern, Central and Southern REZ are not yet sufficiently well defined to satisfy the public policy clause (NER 5.22.3(b)), but assumptions on future development will be tested in a sensitivity to better understand impact on candidate development paths. There are currently no policies specifically targeting storage projects outside New South Wales which are sufficiently detailed to be included in the ISP. Similarly, the impact of renewable energy procurement is not explicitly included as there is insufficient detail on whether these actions will be additional to other policies, or make use of offsets which may not directly affect the NEM.
On specific policy details: **Ausnet Services** stated that AEMO's approach to not extending Victoria's 50% renewable energy target beyond 2030 was inconsistent with the overarching legislation which establishes a net-zero emissions target by 2050. **EA** provided a view that the specification of the storage target in the New South Wales Electricity Infrastructure Roadmap was incorrect by not considering incremental developments, as well as not including the Energy Security Target, and additional cost and revenue implications for generators connecting within REZs.	AEMO has not explicitly increased the Victorian renewable energy target beyond the details specified in legislation; there are not yet sufficient details for specific inclusion in the modelling. In its modelling for the ISP, AEMO will assess the most cost-effective way to achieve any emission targets assumed beyond 2030. This is likely to include further VRE development in Victoria to achieve net-zero emissions in the Victorian power system by 2050. AEMO confirms our understanding that the New South Wales storage target is not intended to be required as a single project, but rather that 2 GW of cumulative build is required by the specified date.

5.3.2 Consumption and demand

AEMO questions:

AEMO included a range of questions regarding electricity consumption and demand (with reference to the most recent 2020 ESOO forecasts), with key questions including:

- Do the electricity consumption component forecasts produce an overall trend that is consistent with your expectations, considering the breadth of uncertainty and consistent with the scenario narratives?
- What factors should be considered in the development of distributed PV, battery storage, and EV uptake? How should potential limitations in the distribution system be incorporated into distributed PV forecasts, if at all?
- Was the breadth of the distributed PV, battery storage, and EV uptake trajectories in the 2020 scenarios sufficiently broad to cover possible outcomes?
- Are the proposed types of battery EV (BEV) charging considered appropriate, and are they reasonably described for the new scenarios?
- Do the economic forecasts reflect a reasonable spread of potential outcomes for the NEM, suitable for continued application in the 2021-22 scenarios?
- Do you support an approach that systematically applies closures using greater traceable logic, over existing methods which put more focus on insights provided during interviews with each facility?
- Are the long term assumptions regarding persisting energy efficiency savings reasonable, despite the cessation of existing schemes that incentivise energy efficiency investment?
- Are the levels of demand side participation (DSP) targeted across the proposed scenarios appropriate for the scenario narrative?

Feedback received	AEMO response
On DER and PV uptake assumptions: **EA** mentioned AEMO should explain material changes to inputs and give stakeholders opportunities to provide feedback. They are keen to understand how the consultant's results drive modelling inputs (e.g. DER and EV uptake). **Nature Conservation Council** strongly recommended the revision the rooftop PV uptake needs in all scenarios and possibly affecting minimum demand. Central Scenario forecast should be revised to 3 GW per annum as suggested by the Clean Energy Regulator's September Quarterly Carbon Market Report 2020, with possible upsides in High DER and Export Superpower scenarios. **Powerlink** also recommended the revision the rooftop PV uptake numbers.	The Draft IASR (including the companion Assumptions Workbook) presented DER assumptions that were published in August 2020. AEMO has acknowledged that these forecasts have understated the uptake of distributed PV. AEMO has updated all of the key inputs in the demand and energy forecasts through the first half of 2021, and has engaged with stakeholders on these updates through the FRG. The updated forecasts address many of the concerns raised by stakeholders by increasing the uptake rates, particularly in the near-term. All scenarios have had upwards revision in the 2021 forecasts, and a High DER sensitivity is also included in AEMO's sensitivity collection. In response to the feedback provided by EA, when presenting their draft DER forecasts in the March 2021 FRG, CSIRO and GEM detailed the major methodology and input assumption changes that changed their latest forecasts relative to the 2020 projections. Stakeholder feedback was

Feedback received	AEMO response
Energy Consumers Australia also noted that AEMO has not included new DER projections in the workbook along with the draft IASR 2021 consultation document. **PIAC** suggested the modelling of a high-DER uptake sensitivity of the Central scenario as the level of DER was previously underestimated. The **ISP Consumer Panel** recommended AEMO develop a summary and log of state budget announcements and ensure these are incorporated into the IASR.	received at that time from participants both during and in the two week FRG Consultation window following the March FRG. Responses to DER consultation feedback were published in a report on AEMO's website[22]. The DER consultants also addressed some of the feedback from the March FRG when they presented their final forecasts in the April FRG. The 2021 PV forecasts are a significant upward revision on 2020. The Net Zero 2050 scenario for the NEM is for 2,650 MW of rooftop PV to be installed in 2021 – this number excludes systems over 100 kW and systems installed in regions outside the NEM. Beyond 2021 the Net Zero 2050 scenario projects uptake to moderate slightly, but still sit at rates above or equal to the 2019 uptake until the end of 2023. The Net Zero 2050 PV forecast is also slightly higher than the strongest 2020 forecast, reaching 29 GW by 2031. The highest PV uptake (in the Hydrogen Superpower scenario) has a higher projection of approximately 34 GW of installed capacity by 2031 in the NEM. As discussed in the March and April 2021 FRGs, PV uptake is expected to moderate somewhat in the future due to factors such as lower midday wholesale prices, lower feed in tariffs, shortening deeming period of small-scale technology certificates (STCs), and network limitations. The scenarios explore a range of extents and timings for this moderation to occur. The Slow Change scenario has also been updated to capture much stronger short term DER uptake as a better sensitivity check against minimum demand. With regards to the feedback from the ISP Consumer Panel, AEMO's consultant reports list the state and federal policies that influence their projections for each relevant component. AEMO monitors jurisdictional funding announcements that may meet the 'committed' policy criteria of NER 5.22.3(b).
On Distributed energy resources impact in the Distribution network: **Energy Estate** recommended the work done by Vibrant Clean Energy, which modelled the impact of DER at a distribution system level in more detail. **ISP Consumer Panel** recommended modelling the impact of DER optimisation by DNSPs and mentioned that EVs are likely underestimated. They recommended that AEMO have conversations with various DNSPs and new service providers to get a greater understanding of current and future investments and changes in network utilisation and energy flows.	While AEMO does not intend to model the distribution system as part of the ISP, AEMO, TNSPs and DNSPs are working to explore how plans to accommodate high penetrations of DER can be leveraged by AEMO to support power system operation and the development of the ISP. DNSPs will continue to use their knowledge and experience to make investment decisions on their network and in the longer term, will assist AEMO in incorporating that information into the ISP where appropriate.

[22] Available at: https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/frg/consultations/2021/frg-consultation-der.zip?la=en.

Feedback received	AEMO response
ENA agreed distribution networks represent a missing piece of the forecasting puzzle and suggested AEMO and networks need to identify unique, local scenarios that each NSP is best placed to provide to AEMO. **Havyatt** argued that DER should not just be forecast but optimised as a variable. Distribution networks should not be assumed to represent a pool of demand and forecast DER.	
On Distributed energy resources impact in the consumption and demand forecasts: **EA** recommended further attention around the growing system challenges of minimum demand and how management of DER from a policy and technical perspective may feedback into consumption and demand forecasts. The **ISP Consumer Panel** recommended that the IASR should not be limited to the uptake of DER but the optimisation and enhanced utilisation of these through increased orchestration.	AEMO considers a proportion of batteries are orchestrated in a Virtual Power Plant (VPP) as part of the current forecasts (with this proportion varying across scenarios) and is monitoring the results of the VPP trial[23] to assess whether a proportion of PV operating in a more orchestrated fashion is also justified. The forecasts currently do not consider other forms of PV control, such as the recent measures being introduced in SA, but will consider this in future minimum demand forecasts where it sees these policies being implemented. AEMO, TNSPs, and DNSPs are working to explore how plans to accommodate high penetrations of DER can be leveraged by AEMO to support power system operation and the development of the ISP. DNSPs will continue to use their knowledge and experience to make investment decisions on their networks and in the longer term, assist AEMO in incorporating that information into the ISP where appropriate.
Other feedback on DER: **MUA** mentioned that the assumption of large scale VRE and public transport is more efficient than high uptake of household batteries and EVs, which would need significant equity measures. **ECA** suggested to explore the interplay between levels of energy bills, trust, and other motivators, particularly the preference for clean energy, and the rate at which consumers invest in rooftop solar PV and other forms of DER. **ECA** recommended the application of a consumer or social practice view on the DER forecasts. The Energy Synapse work undertaken as part of the Energy Security Board's post-2025 market design program should be considered by AEMO in this process.	In response to the feedback from the MUA, the Steady Progress scenario's DER forecasts project consumer uptake based on current announced policies. Electrification of public transport as well as personal transport is considered in the EV forecasts. AEMO is not aware of any evidence to support an assumption of a strong push towards public transport and away from private vehicle ownership but is open to considering this if it can be satisfactorily proven to be a feasible future outcome. The battery projections consider a range of different uptake trajectories depending on the scenario, including considering the potential for low future uptake. The DER consultant forecasters aim to account for the factors raised by ECA in their forecasts and provide detail regarding the primary influences on forecast consumer adoption in their forecast reports.

[23] Virtual Power Plant (VPP) Demonstrations. Available at: https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations.

Feedback received	AEMO response
On DSP assumptions: **Energy Consumers Australia** strongly recommended the inclusion of results of the Energy Synapse report on demand response in the NEM that was commissioned by the Energy Security Board (ESB) as part of the Post 2025 Market Design project. **MEU** concerned at the low amount of DSP (DSP worksheet) that AEMO expects will be provided, especially in the higher price ranges. Suggested that the calculation of DSP needs to be made more transparent with all sources of DSP being clearly identified. **MUA** recommended to include a cost in the modelling regarding new industrial legislation to ensure that workers' rights are maintained for the High DSP assumption.	AEMO has validated its forecast against other data sources, including the Energy Synapse report on demand response in the NEM[24], noting AEMO's Demand Side Participation (DSP) information was one of the key data sources used by Energy Synapse. AEMO also performs assessments of forecast accuracy a year after its release. These assessments are published in AEMO's Forecasting Accuracy Reports[25] and include an evaluation of the accuracy of the DSP forecast. The recent assessments have found good alignment between forecast DSP and observed DSP on maximum demand days, or days with reliability events. AEMO acknowledges that observed DSP responses on some occasions are higher than forecast, but the forecast is meant to establish the average response during different DSP events. It is also noted that AEMO's DSP forecast only reflects some of the demand side flexibility, with other components – such as hot water load control, time-of-use pricing and battery storage use being reflected in AEMO's forecast through different mechanisms. MUA suggests that frequent use of DSP may require new industrial legislation to ensure worker rights. AEMO assumes this will happen in scenarios with a large component of DSP being used regularly, but has not added a cost of doing so. It should be noted that a significant proportion of the forecast DSP is the reliability response, which in AEMO's modelling will be used as the last step before unserved energy. It will therefore see very limited use in most modelling runs.
On energy efficiency: **MUA** noted that there are social and financial limits to energy efficiency initiatives and take up of new appliances. **ACF** recommended the application of NCC Futures across all scenarios. This refers to the Trajectory for Low Energy Buildings, agreed by all energy ministers, which sets a trajectory to zero energy and carbon buildings for Australia. **ENA** also argued that an energy neutral approach should be adopted, like the NCC2022.	The energy efficiency forecasts are underpinned by demand drivers - including economic, dwelling, connections and population growth - that capture social and financial settings under each scenario. For example, the potential for energy efficiency savings from building codes is dependent on the growth of both commercial and residential building stock under each scenario. Similarly, savings from appliance and equipment efficiency improvements are dependent on scenario-specific economic factors. The energy efficiency forecasts consider anticipated future changes to the National Construction Code (NCC) as was raised by the ACF, including anticipated changes to the energy intensity of buildings as a result of NCC Futures, with scenario-specific assumptions. With regards to the feedback from the ENA, the forecasts use savings data from jurisdictions for some policy measures, and fuel mix assumptions would be embedded in the data. For other policies, the consultant has estimated the fuel mix based on the range of activities covered by the policies, as well as historical fuel mix ratios.

[24] At https://energysynapse.com.au/product/demand-response-in-the-national-electricity-market/.

[25] At: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

Feedback received	AEMO response
On Electrical Vehicles forecasts: **Nature Conservation Council** recommended updating electric vehicles forecast to include electrifying the NSW bus fleet by 2030, and the likelihood that other states will follow suit. **EA** argued that trajectories for distributed energy uptake are likely to be particularly affected by using the most recent historical data and policy announcements, and our expectation is that forecast uptakes would be higher overall as a result. The High DER scenario also had highest EV and PV uptake. Further policy developments affecting EV are likely as governments start looking to decarbonise the transport sector. **EA** argued that uptake and charging profiles for EVs are also subject to considerable uncertainty and materiality to the extent of justifying sensitivity analyses. For example, AEMO may wish to model situations where there is significant lag in developing time of use pricing signals and insufficient policy or customer behavioural response to discourage EV charging at times of system peak demand, which would have commensurate impacts on system costs. **Hydro Tasmania** mentioned AEMO needs to consider the full cascading effect of EV on energy demand. **Sligar and Associates** argued that major change will be the electrification of transport at an unknown rate.	AEMO recognise that the speed of uptake of EVs, as well as the characteristics of that uptake, are substantial uncertainties. Accordingly, the EV forecasts have a large spread, and the mix of charging patterns (convenience, time of use etc) are also scenario specific. In regard to recommendation for including New South Wales EV bus initiative, it should be noted that, at the time the 2021 IASR was finalised, targeting the whole New South Wales bus fleet (about 8000 buses) for electrification by 2030 had not yet been legislated and was therefore not considered a 'committed' policy. To date, the only confirmed information is commitment to 120 EV buses in the New South Wales fleet. In some of the modelled scenarios, approximately 8000 buses are electrified by 2030 in New South Wales. Since engaging CSIRO to undertake EV forecasts, additional state initiatives have been announced with varying levels of commitments. As stakeholders have suggested, these developments have tended to push uptake expectations higher, towards the upper range of CSIRO's forecasts. The spread of scenario projections provides coverage of this uncertainty. Present evidence shows that the vast majority of charging is undertaken on convenience basis, which AEMO's scenarios retain until material EV penetration is observed. As such, AEMO's default profiles incorporate a lag before charging coordination, or alternative charging options are used, and this speed of transformation varies across the scenarios. AEMO may retain the option to consider EV charging as a form of sensitivity analysis, but would need to consider it a material influence on the actionability of investments. The timing of these investments and the timing of material EV integration may mean that EV charging may be more influential on future projects.
On economic and population growth drivers: **MMTech** argued the number of Australian's returning from overseas is not seemingly acknowledged in the demand input. **Sligar and Associates** mentioned the economic forecasts are appropriate. Greatest disturbance would be coal and LNG exports being affected by climate action, reducing Australia's trade income.	Economic, dwelling and population forecasts have been provided by AEMO's economic consultancy and detail the impact that lowering net overseas migration (including migrant and citizen movements) has had on the Australian economy. This flows through the consumption models as an input. AEMO notes the feedback from Sligar and Associates, and also notes that changes to the coal and LNG exports are material and model the electricity loads from these two sectors explicitly using the economic forecast and scenario narratives.
Other on consumption and demand: **MUA** mentioned specific planning should be undertaken to ensure that the future grid provides secure supply for large industrial loads. This should be explicitly addressed in future ISPs to reduce community anxiety and preserve jobs. The ISP suggests to close power stations near loads and replace them with VRE located hundreds of km away.	AEMO models a range of scenarios that test outcomes for the large industrial loads. The Slow Change scenario models grid impacts with potential industrial closures, while other scenarios broadly experience industrial load growth, capturing existing loads and new load electrification. The engineering assessment of the ISP endeavours to ensure that VRE supplied remotely from existing loads is reliable and secure, and is complemented by AEMO's Engineering Framework to achieve this. AEMO survey individual large energy users on an ongoing basis, which incorporates questions regarding these elements, particularly the on-site alternative supply investments regarding

Feedback received	AEMO response
The **ISP Consumer Panel** recommended further engagements with organisations representing large energy users on the consideration of LILs, non-network options and energy efficiency forecasts. **Sligar and Associates** requested a log scaled chart showing magnitude and variability of the various components of load to give a better sense of proportion in the IASR. **MEU** argued POE10 is too high and AEMO is being excessively conservative.	efficiency and embedded generation (such as PV installations) that each load may be considering investing in. AEMO does release data on the scale and magnitude of the electricity consumption components, which is available at http://forecasting.aemo.com.au. With regards to the peak demand forecasts, AEMO follows a public methodology that is consulted on with industry on an ongoing basis, and uses different levels of maximum demand outcomes to reflect different underlying weather conditions that can drive extreme peak consumption. These outcomes are then weighted to provide an appropriate spread of USE outcomes in the ESOO, and a consistent approach is taken for ISP purposes.

5.3.3 Existing generator and storage assumptions

AEMO questions:

- Do you have specific feedback and data on the assumed technical and cost parameters for existing generators?
- If you are an operator of an existing generator, do you have any specific technical and cost data that you are prepared to be used in AEMO's modelling? It would be preferable if this was data that was able to be published, but data provided on a confidential basis would also be considered.
- Do you have any comment on the forced outage rate inputs and their application in AEMO's models?
- Do stakeholders support AEMO's proposal to remove coal-life extensions across the scenarios (noting that the inclusion only featured in the Slow Change scenario in 2019-20)?
- What approach should be used in determining the timing of coal closures in the Sustainable Growth scenario? If you consider that early retirements should be treated as an exogenous input, should this be applied consistently to all power stations, or should only specific power stations be identified and brought forward?
- Do you believe that the Slow Growth scenario should allow for the extension of generator retirements beyond their expected closure years if economic to do so? If so, what purpose does this achieve?

Feedback received	AEMO response
On VRE capacity factors:	Capacity factors of existing projects reflect the historical observed generation levels across the reference years that each project has been in operation.

Feedback received	AEMO response
The **MEU** argued that capacity factors for VRE seem high compared with actual capacity factors in Global-Roam 2020 Generator Statistical Digest.	Capacity factors of REZs are based on the site-specific half hourly renewable generation profiles developed by AEMO using historical meteorological data for the site, and an energy conversion model based on the generator technology. These generation profiles model what each generator would have produced if it was operating during the reference period and not constrained by the limitations of the network (which is captured within the ISP models directly, through different means). The VRE capacity factors given in Global-Roam's 2020 Generator Statistical Digest are based on historical dispatch profiles of VREs which implicitly include impacts of any network constraints. Furthermore, the REZ capacity factors are based on new entrant generation technologies, which in the case of VRE may achieve higher capacity factors than existing generation developments.
On outage rates: **EA** notes that AEMO's workbook does not list outage rates for renewable plant and noted these have been included implicitly in the relevant generation profiles. Also requested additional transparency regarding both the assumptions and methodologies used, and insights into why taking forward historical observations is the best approach when considering aging maintenance influenced plant and equipment. **Hydro Tasmania** suggested to align assumptions of thermal outage rates to be based on age of plant and observed behaviour of increased tripping and decreased reliability. The **MEU** argued that forecast outage rates for existing generators seem high, especially when compared to the settings used for new generators. The **FRG** requested clarification on long duration unplanned outages.	The detail on historical forced outage rates and projected outage rates are provided by participants themselves in most cases. For ISP timeframes, interpretations typically preserve participant trends. Since the 2020 ESOO, AEMO has developed forward-looking forced outage rate trajectories which are intended to take into account changes in operation behaviour and age on generator reliability. These projections are provided in the Assumptions Workbook. AEMO has consulted on the approach to calculating forced outage rates through the FRG over recent years, and the outage rates are based on recent historical observed performance as supplied by generators, adjusted for forward-looking projections as described in the 2021 IASR. The forced outage rates assumed for new entrant generators are generally lower than those applied to existing generators, though this reflects the general age of the existing generator fleet. The existing generator outage rates are based on an aggregation of existing stations; the performance of the better stations within these aggregations is often equivalent to the new entrant outage rate assumptions. As EA notes, outage rates for renewable plant are incorporated in the renewable generation profiles. These profiles are derived from actual renewable generation output where available and suitable. Such data implicitly includes generator outages and maintenance already; it would be infeasible to eliminate these events from the data due to the difficulty in detecting their occurrence, in particular partial outages. Furthermore, the profiles applied are used across all new entrant generators in REZ, and are therefore ultimately applied to generators at different points in their life. The profile applied is considered to represent a reasonable view of average life-time performance, and the inclusion of deterioration over time would add significant complexity with minimal incremental value. AEMO confirms that long duration unplanned outages are unplanned outages of greater than 5 months duration, and calculates these for each region and technology class. Treatment of these outages in the ISP Methodology is to ensures that there is no systematic bias for generation or transmission when assessing the value of alternative options for addressing reliability.
On technical parameters, ramp rates, min up/down, min load:	On ramp rates, AEMO's historical analysis has shown that for some stations, the ramp rates provided in the Draft IASR were low compared to realised performance, but for other stations were high. Based on the

Feedback received	AEMO response
The **MEU** argued that ramp rates seem quite low compared with data provided by the original equipment manufacturers' (OEM) statements of capability. **EA** argued that AEMO should use conservatism in its modelling rather than assuming maximum ramping rates are achieved all the time, and outline where and how it has captured findings from its Renewable Integration Study into inputs and assumptions. **TasNetworks** encouraged minimum stable load assumptions for coal fired generators of 60% and 42% for brown and black coal units respectively (from the Aurecon report) to go into the IASR. The **MEU** argued that start times for gas turbines seem too long. Most gas turbines (based on OEM data) can start faster while **EA** argued that min up and down times for coal generators need to be reviewed given the growing pace of change of the system.	suggestion from EA to consider the Renewable Integration Study (RIS), AEMO has refined the ramp rate assumptions for coal generation to reflect the approach used in the RIS, and described in the 2021 IASR. On minimum stable levels (MSLs), AEMO has reviewed its assumptions for existing generators using both historical analysis and operational expertise. For new entrant coal generators, MSL is sourced from the 2020-21 Aurecon report[26]. While AEMO considers that start times for less flexible gas generators are generally appropriate, start profiles won't be explicitly modelled as explained in the ISP Methodology. On minimum up- and down times, AEMO notes that these will only be modelled on combined cycle gas turbines (CCGTs) and gas-powered steam turbines. This is due to the difficulties in understanding the true capabilities and cost impacts of frequent coal cycling. Further detail is provided in the ISP Methodology on AEMO's approach to coal decommitment in response to increasing VRE penetration.
On Fixed OPEX: **EA** argued that the definition should be made clearer, namely whether this is purely relating to operating costs (as per standard profit and loss approaches), or whether it also includes stay in business capex, which aims to maintain or upgrade both reliability and capacity.	AEMO has sought feedback from participants to consolidate assumptions and definition of fixed OPEX. AEMO has reconsidered the definition of fixed OPEX and how this cost will be represented in the modelling. The updated assumption is described in the 2021 IASR.
On coal generators: **EA** noted AEMO's assumptions do not appear to include start costs for coal generators. **Energy Estate** recommended the ability for the modelling to be able to repurpose coal-fired power stations as batteries, synchronous condensers or gas/hydrogen-powered generators rather than assuming all new assets are located close to available renewable resources.	AEMO does not presently explicitly optimise coal unit commitment in the ISP modelling, and as a result, start costs are not an input to the market modelling. While modelling suggests that there are strong drivers for flexible operation in the future, it is not well understood whether coal plants are technically capable of changing their current regimes and the commercial viability of it. This is an ongoing area of development, and AEMO has sought feedback from stakeholders to improve its modelling capability in this respect. AEMO has not explicitly considered the ability to repurpose coal-fired generators as other generators, but does not assume that these resources are always located near REZs. The ISP capacity outlook models do consider where to locate new entrant technologies which does have some consideration of transmission limitations and access to large loads.
On the approach to coal retirement:	AEMO has considered the feedback on coal retirements, and provided further clarity on the approach and assumptions for the assessment of coal retirement in the ISP Methodology. This approach takes into account both pricing outcomes and the impact of carbon limitations, depending on the scenario, incorporating the impact of policies that may drive increased competition and reduce coal operations.

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

Feedback received	AEMO response
ACF argued that in Table 4 (Public Policy Settings) in the Draft IASR, generator retirement dates may be influenced by decarbonisation objectives in Central, diversified or slow growth where power station owners are based in high ambition countries. **EA** argued that AEMO's scenario modelling should allow for plant to close for economic reasons as a model output, rather than have closure dates set as modelling assumptions. Retirements should be modelled on an economic basis, with closure decisions also made where prices and revenues fall to unsustainable levels. It is not clear whether AEMO's modelling approach can accommodate this as it does not appear to produce market prices as an output. **Energy Estate** supported an approach to determining the timing that looks at each unit in the coal-power fleet specifically rather than treating them all the same and agreed with the proposal to remove coal-life extensions across scenarios (p 88 of the IASR) while **Sligar and Associates** agreed with the coal retirement approach proposed in the scenario settings. **MMTech** argued the absence of an acceptable economic solution for mid-term VRE storage and consequent need for more gas plants following coal retirements is not apparent in the inputs. **TasNetworks** recommended AEMO should carefully consider assumptions for coal retirement as capacity factor for NSW black coal generation is likely to reduce further due to acceleration of renewable penetration, and requested AEMO's modelling to reflect state-based legislated policies when considering thermal retirements. **IEEFA** suggested modelling QLD early coal retirements (as well as Vic and NSW). **Central Queensland Power** argued coal retirements in and around Gladstone are likely to be more accelerated than anticipated by AEMO, and will necessitate grid augmentation well before the 2030s. **AusNet Services** stated that the closure assumptions for Yallourn should be updated to reflect recent announcements, and to consider the implications on forced outage rates and the retirements of other generators.	AEMO will, therefore, deploy a slightly different approach depending on the scenario. Section 2.5 of the 2021 IASR specifies the approach used in each scenario. Details on generator retirement approaches are available in Section 2.4.1 of the ISP Methodology, noting that this approach is applied to all generators and may bring forward coal retirements in one or more regions. AEMO's modelling however does not extend to considering the commercial return expected for new storage developments, with new storages (if selected) developed to minimise the overall system costs, rather than maximise arbitrage opportunities. As such, the ISP outcomes may continue to demonstrate a need for storages and the role of the broader market reform package being considered by the industry, Energy Security Board and Australian Energy Market Commission should be informed by the cost-based preference to deliver storages (if preferred), in determining future market changes that can support this outcome more than current settings may.
On Generation Information (GenInfo)[27]**:**	The GenInfo tables simply report capacity in each technology category. The role of different technologies including batteries is accounted for in the modelling. It is not the case the available capacity is double counted in the modelling, but users of GenInfo should note that the capacities of various technologies

[27] The Generation Information page is updated at least quarterly, and available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Feedback received	AEMO response
MMTech noted that GenInfo tables may be double counting available capacity, as they include in the same table the underlying energy source as well as battery capacity. **IEEFA** suggested that 802 MW of solar and 621 MW of wind projects from the Generator Summary tab (Existing, Committed and Anticipated Generators) were omitted. It also suggested the inclusion of private sector renewables driven installation targets (e.g. Woolworths 100% renewables by 2025). The **ACF** also suggested that some large-scale battery announcements had not been included. **Walcha Energy** suggested an improvement is required in the derivation of generation information and suggested AEMO needs to be more pro-active in seeking out intended new Generator connections, and include these within the Generator Information survey.	cannot simply be added to determine available capacity (storage does not charge and discharge at the same time). AEMO includes all committed and anticipated projects (that it is aware of) in all future states of the world, in accordance with the CBA Guidelines. In order to assess the level of project commitment, the RIT-T instrument defines five commitment criteria that the CBA Guidelines require AEMO to use when assessing the commitment status of generation (and transmission) projects for the purposes of the ISP. The Generation Information is updated quarterly with the latest available information provided by project developers and market participants, though not all developers are obliged to provide the information requested by AEMO through the Generation Information process. AEMO therefore thanks stakeholders for bringing other projects to our attention. The latest GenInfo release (July 2021) is incorporated within the ISP and ESOO publications, and AEMO believes this to be the best reflection of current commitments as well as those projects deemed anticipated, recognising that many projects may have announced development intention without achieving the necessary criteria to be deemed as 'anticipated'.
Other feedback: **EA** commented on potential improvements to modelling generators (e.g. refurbishment cycle should be 4-6 years instead of 10 years, if the model considers costs associated with lumpy outage cycles and SA reserve margin assumptions outdated with current largest unit). The **Climate Council** recommended AEMO revisit assumptions around the assumed emissions intensities of generators in the NEM.	AEMO thanks EA for this recommendation. In engaging with generators on fixed operating assumptions, the approach to the refurbishment cycle had been removed, with these costs instead included in the annual fixed and operating costs. This is because many stations use rolling maintenance and overhaul schedules, and because it is not possible to forecast with any certainty the years in which more significant expenditure may be required. AEMO thanks Climate Council for this recommendation and has updated the emissions intensity assumptions to reflect the latest available information.

5.3.4 New entrant generator and storage assumptions

AEMO questions:

- Is AEMO's proposed list of candidate technologies reasonable? If not, what should be included/excluded?
- Do you have specific feedback and data on the assumed current and projected costs for new generation and storage technologies?
- Do you agree with AEMO's proposal to use the same regional cost factors used in the 2020 ISP for its 2021-22 modelling? If not, please provide suggestions for improvements or alternative data sources.
- Are there other social licence or competing land-use cost considerations that should be factored into these regional cost factors, or that would require use of more granular sub-regions?

- Do you agree with these proposed technical parameters and fixed and variable operating and maintenance costs of new entrant technologies? If not, please provide suggestions for improvements.
- As Entura pumped hydro cost estimates are location- and resource limit-specific, should AEMO modelling consider an expansion of PHES limits at higher cost?
- Are the cost assumptions for pumped hydro reasonable?
- Is the proposed approach to modelling battery storage technologies appropriate, particularly with regards to the end-of-life assumptions?
- Is the proposed approach to accounting for storage degradation appropriate, or would an alternative approach be more effective in representing battery storage degradation?

Feedback received	AEMO response
On candidate technologies: **ACF** argued that Advanced ultra-supercritical black coal with CCS and CCGT with CCS should be excluded, as the reasons used to exclude new brown coal generation, geothermal and tidal wave also apply to them. Similarly, **ACOSS** argued that CCS will never be competitive with other clean energy. **Hydrostor** and **Energy Estate** argued that Compressed Air Energy Storage (CAES) should be included in the list of technologies to be available in the 2022 ISP since there are now sufficient project examples such as Broken Hill A-CAES project and US projects. **Central Queensland Power** supported Hydrostor's submission on CAES technology. **Central Queensland Power** argued that the ISP does not anticipate in detail the full range of storage options. Emerging technologies need to be considered in further detail. **Energy Estate** believed that the input assumptions should contemplate alternative BESS technologies such as iron flow batteries in view of their attractiveness for long duration options. **Hydro Tasmania** argued that Aero-derivative generation assets (more responsive generators) should be considered, rather than OCGTs. **EA** supported the additional flexibility of two sizes of OCGT in the mix of new entrant generation plant	The list of technologies in the ISP reflects the potential generation technology mix, based on scenario narratives, technology maturity and resource availability. At the same time, it considers the number of options required to maintain the model's computational feasibility without compromising its accuracy. On CCS, AEMO considers this technology should remain as part of the candidate technologies list and let the least-cost expansion model determine if it should be selected. On storage technologies, AEMO acknowledges that there is a range of alternative storage types with various maturity levels. Currently lithium-ion technology is considered lowest cost of these, and alternatives are not considered to be more competitive. AEMO continues to focus on storage depths rather than the specific technologies that may operate in the storage role. On aero-derivative technologies, AEMO notes that there are alternative generation technologies that could provide more flexibility than OCGT's, but the capacity outlook models, at the moment, do not capture sub-hourly characteristics where these differences are distinguishable. To improve flexibility representation in the modelling, two sizes of OCGTs are included. If a technology is not competitive, that will be determined within the model, and AEMO notes that some recent developments have been for larger OCGTs.

Feedback received	AEMO response
On projected cost for new generation and storage technologies: **TasNetworks** suggested additional analysis on the diversity of cost projections specific to storage technologies, which will impact cost projections across scenarios. **MUA** and **Star of the South** argued that the assumed cost for offshore wind is too high based on current trends. MUA recommended to engage the developing offshore wind industry and look at US costs.	CSIRO has considered the stakeholder feedback on technology cost trajectories as part of the 2020-21 GenCost final report, and increased the learning rate which resulted in faster cost reductions. Further details can be found in the CSIRO report[28].
On capacity factors: **MUA** argued capacity factors used for REZs in the ISP should reflect the differences between onshore and offshore wind. The Gippsland REZ capacity factor is listed with no distinction between onshore and offshore. For offshore it should be much higher, 45-55%.	AEMO provides separate capacity factors for offshore wind in the Capacity Factors sheet of the Inputs and Assumptions Workbook. These values are distinct from the high and medium onshore wind capacity factors and reflect differences in resource quality and technology for offshore wind. AEMO has added Offshore Wind Zones (OWZs) in locations where offshore wind projects are being investigated. These now make the distinction with on-shore REZs clearer.
On other battery technical parameters: **Hydro Tasmania** argued that battery charge and discharge efficiencies should be more realistic and considered in models. **GE** argued that it is necessary for the modelling to allow for faster degradation and shorter lifetimes for batteries and the modelling should calculate the degradation as an output of the number of cycles rather than assuming a fixed value as an input. **APGA** expressed their concern that the modelling undertaken in ISP of typical/average conditions is not well suited to modelling investment decisions of storage/generation assets during low VRE output. They also emphasised the importance to consider the limitations of storage technologies relative to GPG in the event of prolonged reduction in VRE.	Aurecon's round trip efficiency figures are based on high voltage point of connection (including balance of plant losses and auxiliary power consumption). There is considerable difference in auxiliary power consumption between different BESS OEM with different cooling system designs. The assumptions represent indicative mid-range figures based on current OEMs offerings. On degradation, AEMO acknowledges the limitations of battery storage modelling in the capacity outlook model. The battery storage inputs applied in the modelling use an average degradation which AEMO considers is sufficiently representative of lifetime performance. Incorporating degradation as a function of operating cycles is a complexity not currently feasible without material compromise elsewhere in the modelling approach. Regarding APGA's feedback, the capacity outlook models use multiple weather years to capture a range of possible weather conditions to ensure that low VRE output during periods of high demand is considered. This incorporates specific weather conditions rather than typical / average outcomes. Further testing in detailed time-sequential modelling which does incorporate more conditions in greater granularity around generation outages is used to validate the outcomes of the capacity outlook modelling, and to explore the potential role of GPG. If the detailed modelling identifies a systematic issue within the capacity outlook modelling approach, this is corrected in the iterative modelling approach. This modelling approach is explained in more detail in the ISP Methodology.

[28] Available at: https://www.csiro.au/-/media/EF/Files/GenCost2020-21_FinalReport.pdf.

Feedback received	AEMO response
On pumped hydro cost: **GE** is interested in better understanding the basis of the 50% uplift to PHES costs. Entura's analysis appears to allow for expected increases in capex, so 50% uplift appears to be double counting. While pumped hydro energy storage (PHES) may not benefit from a cost curve effect, it clearly enjoys significant economies of scale, duration and head, and noted that the work undertaken by Entura provides a sufficient basis for a more nuanced approach to pumped hydro. **Hydro Tasmania** suggested that AEMO should not increase PHES cost in TAS due to regional factors and to review cost assumption of 24/48 hour storages in TAS.	The 50% uplift was applied as part of the 2020 ISP process based on feedback that costs has been underestimated given the uncertainty in pumped hydro costs, and due to the higher risks and barriers to investment in PHES compared to other technologies. Given the Cethana project[29] (part of the Battery of the Nation) has been significantly progressed, AEMO has used the centre of the estimated cost range of this project, without any uplift, to recognise the greater level of accuracy in this cost estimate. The generic cost estimates proposed in the Draft IASR are comparable to the Cethana cost estimates once regional differences are taken into account, and AEMO therefore does not propose to make any changes to these cost estimates (noting the likelihood that site-specific geological assessments are needed for increased cost accuracy).
On pumped hydro technical parameters: **Hydro Tasmania** argued that the economic life of hydro plants should be 40 years (not 30 years). **Origin** argued that the assumed 0% maintenance on pumped storage appears to be optimistic. AEMO should consider modelling some outages for more realistic planning.	AEMO thanks Hydro Tasmania for this feedback and the GenCost process has updated the economic life of pumped hydro to 40 years. GHD does provide an assumed maintenance rate equivalent to 1-day per year for pumped hydro. The Inputs and Assumptions workbook has been updated to reflect this rate.
On pumped hydro location: **GE** noted that in the absence of individually costed projects, a compromise could be to model the known developments in each REZ and then develop a chart similar to the one for solar PV. **Hydro Tasmania** argued that VIC, QLD, SA should not have 24/48 hours storage options due to a lack of suitable sites.	AEMO continues to use location PHES limits that are based on the Entura report, adjusted for announced projects as per the Draft IASR assumptions. AEMO acknowledges that there may be the potential for feasible projects elsewhere, or greater availability in some locations but there exists such significant uncertainty in costs due to factors such as geology that it is not reasonable to assume these would be available at a reasonable cost. AEMO considers that the current approach appropriately balances cost uncertainty against potential site availability. AEMO has not removed the 24- and 48-hour options, as these projects would be technically possible (for example, by simply reducing plant capacity). The cost assumptions in these regions reflect the challenges in this availability given high increase in the per-hour storage costs for deeper storages compared to Tasmania and New South Wales.
On regional cost factors: **MUA** noted that values for offshore wind under the Regional cost factor tab should be reviewed. It should reflect access to ports and the available space in ports. MUA also argued that the locational cost and technology cost breakdown ratios for offshore wind has to be	AEMO notes that the regional cost factors are in part based on proximity to ports. Cost factors have been adjusted to remove regional differences such that locations with good port access generally have a cost factor of 1.

[29] Information available at https://www.hydro.com.au/clean-energy/battery-of-the-nation.

Feedback received	AEMO response
lowered as land is not privately owned, no road transport is needed, and fuel is cheaper as it is imported through port terminals. **Walcha Energy** argued regional cost factors should be amended from the 2020 ISP. Walcha Energy cited that NSW and QLD were too high compared to Victoria, and suggested further analysis be undertaken on this for the 2022 ISP. **Energy Estate** argued that regional cost factors do not reflect the different cost structures found across regional towns and cities in the NEM, and is rather based on population distribution. In addition, AEMO's locational cost factors are incorrect, specially figures related to Victoria vs Queensland and NSW. Further analysis for the 2022 ISP is recommended. Social licence and competing land-use cost assumptions should be explicitly taken into account in regional cost factors. **Hydro Tasmania** argued that state-based cost multipliers should be reviewed and consider alternative methods, e.g. Cost of living index provided by ABS. It also noted that locational cost factors should be consistent between Draft IASR and GenCost.	The cost drivers for offshore wind and differences with on-shore locations (such as land issues, road transport, etc.) are considered through the development of generator cost assumptions, as they are present also in existing projects globally. AEMO has amended the regional cost factors to maintain some impact from proximity to cities and ports, but has normalised each state to remove inter-state differences based on this feedback provided. In future ISPs, AEMO will continue to explore approaches which take into account issues related to competing land-use and social license which are also considered in the determination of technology build limits.
Other feedback on new entrants assumptions: **Ai Group** argued that final scenario outcomes will be sub-optimal because inputs on most relevant future technologies aren't mature. **MUA** argued that offshore wind can be expected to make a significantly higher contribution to peak energy demand, and its peak contribution factor should be modelled separately and included in the ISP.	AEMO acknowledges that there may be technologies which have not yet reached maturity but may play a role in the future development of the power system. However, it is impractical to provide input data on technologies still in early stages of their development, and difficult to predict when they may become commercially viable. As such, for the ISP, AEMO considers candidate technologies which are relatively mature. AEMO welcomes MUA's suggestion and will calculate firm contribution factors separately for offshore wind using the revised methodology outlined in the ISP Methodology, which considers the Effective Load Carrying Capability of different technologies.

5.3.5 Fuel assumptions

AEMO questions:

- Do you have any feedback on the assumed coal and gas price trajectories?
- Do you consider the continued use of biomass and liquid fuel prices from the 2020 ISP appropriate, updated for CPI? If not, do you have more specific and up-to-date data on these prices?

Feedback received	AEMO response
On coal prices: **EA** noted that AEMO has assumed a brown coal fuel price of $0.6/GJ for all Victorian generators for some time now and request for further information on the basis of this assumption. They also questioned the assumption that coal prices for Bayswater significantly increase in the late 2020s, from being the cheapest of NSW coal generators to the most expensive, which does not appear to accord with its particular location and access to fuel. Also regarding coal costs, they stated that the AEMO assumptions do not appear to consider volume constraints, which is potentially a material omission from its suite of assumptions and methodologies.	AEMO clarified that coal fuel prices are presented on an 'as delivered' basis, inclusive of mining and royalty costs. Coal prices for some New South Wales generators have been revised upwards, based on available information regarding coal quality and export assumptions. With these revisions in place, forecast coal prices for Bayswater are more aligned with that of other coal generators in New South Wales. Wood Mackenzie developed the coal price forecasts based on a set of generation forecasts provided by AEMO, as a means of considering volume-related pricing impacts. AEMO collects information on generator energy constraints through the Generator Energy Limitations Framework (GELF). For all existing generators, AEMO is guided by these participant submissions to determine if there are any material volume constraints on fuel.
On gas prices: **EA** stated that there is a material difference in fuel prices underlying the 2020 ISP produced by CORE and those now presented by LGA, with limited apparent change in drivers over this time, although noted that the LGA forecasts were in alignment with their expectations. On specific gas production costs, they stated that Gippsland pricing (based on EnergyQuest) is likely to be in the 2C range instead of the 2P range due to the high costs of removing CO_2. **APGA** recommended that gas prices are sourced from an independent expert with evidence-based alternative views. **Hydro Tasmania** noted that AEMO should consider including Fixed Costs for gas transportation. The **ISP Consumer Panel** considered that gas prices were a significant assumption in the ISP. The ISP Consumer Panel raised concerns about the stakeholder engagement process, the lack of transparency provided in relation to the methodology used to develop the gas price forecasts, and on the various assumptions which underpin the forecasts. In addition, **MEU** stated that there is a disconnect between the forecast gas prices provided by LGA for industrial gas users, the forecast for gas fired generation (fuel price summary worksheet), gas and liquid fuel price worksheet, and the combination of data from worksheets on gas transmission tariffs and gas production costs.	AEMO has worked with the ISP Consumer Panel to improve the stakeholder engagement process and transparency on methodology and inputs to gas price forecasts, and to create an opportunity for stakeholders to provide feedbacks on reasonableness of forecast prices. AEMO held a public dedicated workshop dated 24 April 2021 (in addition to regular FRG sessions) with representatives from a broad range of stakeholders (including industry, government, academia, consultants, retailers, and providers). The materials for this workshop were published at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement. This workshop explored the feedback in detail and provided participants with direct access to Dr Richard Lewis, of Lewis Grey Advisory (LGA), who produced the forecasts. Gas prices were recognised as a notable driver of operational costs which influenced the net market benefits identified within the 2020 ISP for some ISP projects. While gas remains important for firming the power system, low forecast gas operations from GPG is likely to reduce the sensitivity of ISP projects to gas prices as more VRE and storage develop. Nonetheless, to improve the understanding of the influence of gas prices on the cost-benefit assessment in the 2022 ISP, AEMO will include a Low Gas Price sensitivity to determine the impact that low gas prices might have on the ODP. Regarding Hydro Tasmania's suggestion of including fixed costs in gas prices to reflect gas transportation costs, AEMO's gas prices presently includes a fixed allowance for transport and storage costs for different customer categories on a per unit ($/GJ) basis, with low utilisation peaking gas plant paying a higher relative premium to reflect the increased costs associated with that service, and greater reliance on storages. While these costs intend to recover associated transport and service costs, it may not make whole these charges on a total cost basis ($M per annum) if significantly underutilised.

Feedback received	AEMO response
	Regarding the MEU concern, the price for GPG and the price for industrial gas users do have differences and both come directly from LGA's modelling. The perceived inconsistencies may be due to accounting for capacity payments from GPG operators – recognising the need for pipeline capacity without necessarily high utilisation. This was discussed in the Gas Price Workshop. The published data is slightly modified to allow for changes in financial years.
Other feedback: **Climate Council** stated that it is implausible that sustained low coal (and gas price) could occur under pressure to decarbonise in the Sustainable Growth and Export Superpower scenarios. Hence, AEMO should revisit the assumed fuel prices in scenarios with high levels of decarbonisation. **Sligar and Associates** commented that it is likely that various economies will reduce/stop their import of coal/ LNG from Australia, resulting in greater availability/reduced price domestically.	Under scenarios with a high level of decarbonisation there is a rapid decline in global demand for fossil fuels, particularly coal. As a result, the direct fuel prices will be lower relative to the other scenarios. For some scenarios, the economics of operating emissions-intensive generation will be considered against the need to decarbonise the economy to achieve the carbon budgets that exist in the scenario parameters. This may require reduced operation from coal and gas plant, such that the marginal cost of fuel will be an input of declining significance.

5.3.6 Financial parameters

AEMO questions:

- Do you have specific feedback and data on alternative sources for weighted average cost of capital (WACC) and discount rate?
- Is the proposed approach to applying a lower discount rate in the Slow Growth scenario appropriate?
- Is the proposed application of volume-weighted regional VCRs appropriate?

Feedback received	AEMO response
On discount rates: **ISP Consumer Panel** stated that AEMO's (proposed discount rate settings) does not meet the requirement of the (Forecasting Best Practice Guidelines). They noted that AEMO has not attempted to calculate a commercial private sector rate, but has over-relied on ENA and AER determinations. Additionally, more analysis is needed to justify the proposed decrease in WACC for the slow growth scenario, and why the WACC is commensurately not higher for the	AEMO thanks stakeholders for the considerable level of feedback received on the issue of discount rates and their application in the ISP. As a result of this feedback, AEMO engaged Synergies Economic Consulting to determine appropriate discount rate settings, including considerations of whether alternative discount rates should be applied in any circumstance (e.g. in certain scenarios or for particular investments). As

Feedback received	AEMO response
sustainable/superpower scenarios. The Panel also questioned why a 2% discount should apply for investments that qualify for the New South Wales Electricity Infrastructure Roadmap. **EA** noted that network determinations for regulated monopolies in the current economic environment are likely to materially understate risk adjusted return expectations for market based competitive generation investments, particularly over the longer-term modelling horizon of the ISP, noting risk free rates are at historical lows. Furthermore, they stated that AEMO should also consider that private sector investment in NSW generation will likely be brought on through some form of government involvement, with commensurate reductions in risk. **MEU** suggested that a discount rate of 4.8% (3.8% for slow growth) might be acceptable for assessing the NPV of future revenues from network investments. They also noted that a discount rate for future consumer benefits arising from the network investment needs to be 12% at least, and that a discount rate for assessing the future revenue from generation investment probably lies between 4.8% and 12% and closer to the higher discount rate for future consumer benefits. **ENA** suggested the lower WACC for generation projects within REZs goes against general principle that generation and transmission should have the same discount rate. They also suggested that the proposed discount rate appears reasonable, but AEMO needs to satisfy itself that it meets the CBA guidelines.	a result of this engagement, the central discount rate assumptions have been increased, and a range of discount rates have been determined which will be used for sensitivity analysis. Synergies also concluded that it was not appropriate to apply different discount rates to generation and transmission investments Further details on the assumptions and methodology used to determine these discount rates can be founded in the Synergies report[30].
On VCR: **ENA** recommended AEMO to use a volume-weighted VCR, including agriculture, commercial, industrial and large business, rather than residential VCRs by state while **Ausnet Services** suggested that the NEM regionwide customer-weighted VCRs are the appropriate figures to use.	AEMO has considered the feedback on VCR and will use customer load weighted state VCRs provided in the AER report[31] for cost-benefit analysis in the 2022 ISP, on the basis this will reflect the VCRs of the customer composition on the network as per the CBA Guideline.

5.3.7 Climate change factors

AEMO questions:

- Are the assumptions considered appropriate?

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

[31] AER values of customer reliability: Final report on VCR values, December 2019, at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf.

Feedback received	AEMO response
On temperature impacts: **EA** recommended AEMO to review firmness assumptions for inverter connected equipment and performance of underlying wind resources during extreme max temperatures. **PIAC** recommended that AEMO increases the transparency and accessibility of information regarding how temperature change assumptions will impact Australia, particularly the energy system, under each scenario and how they factor into the choice of ODP.	As proposed in the 2020 Forecast Improvement Plan[32] AEMO has revised the process for developing wind generation traces, to improve modelling of wind generator output during extreme wind and temperature events. These improvements have been successfully deployed for the 2021 ESOO and draft 2022 ISP. AEMO believes that the current implementation of solar generation traces process sufficiently captures expected performance during extreme temperature periods. AEMO seeks to align climate change trends appropriate for each scenario, capturing differentiating impacts between scenarios in modelling where relevant, noting however that the physical impacts of climate change are only expected to become materially different towards the end of the century, beyond modelling time frames for the ESOO and ISP.
On climate change impacts: **TEC/Renew** argued that the IASR goes into little focus on climate change impacts of each scenario. They recommended that each scenario includes the implications for the electricity sector, and consumers, of relevant emission outcomes by 2050. These have not been clearly articulated, and include changing loads due to shifting populations, changing average temperatures and diurnal heating and cooling patterns, etc. **TasNetworks** suggested the development of synthetic weather traces to better reflect extreme weather events, which would then inform generation assumptions and transmission build. **Hydro TAS** suggested to increase forecast energy consumption for hydro due to ongoing climate impacts. Hydro TAS offered to share analysis with AEMO on long-term impacts of climate change on their hydro plants. **Havyatt** recommended consider the modelling from the ESCI Project. **MUA** argued that bushfire risk must be included for transmission line assessments, but AEMO must ensure its not applied to underwater or underground cables.	In response to ongoing feedback regarding the importance of the physical impacts of climate change, AEMO is working towards modelling of climate change impacts in forecasting and planning decision making via multiple pathways including: • Incorporating relevant and meaningful climate trends in quantitative market and power system modelling where consistent with the intent of the modelling and each scenario. Including: • Hydroelectric and desalination dam inflow changes. • The effect of temperature increases on consumer demand. • The effect of temperature increases on transmission line ratings (Victorian dynamic line ratings for time-sequential modelling only). • Increasing bushfire impacts on overhead transmission line failure rates (reliability forecast only). These inputs were updated for the 2021 IASR using the most recent science, as advised by BoM and CSIRO. In future ISPs, AEMO will consider more closely the anticipated temperature related impacts on inverters and VRE and distributed resources. Developing extreme event case studies that stress test power system designs and outcomes against the acute impacts of climate change, to help design appropriate responses and differentiate between investment options. These case studies will allow for consideration of these risks that, due to limitations in both climate and power system modelling, cannot be fully quantified. The case studies will include consideration for:

[32] At https://www.aemo.com.au/consultations/current-and-closed-consultations/2020-forecast-improvement-plan-consultation.

Feedback received	AEMO response
	• Hail, cyclones and storms • Extreme heatwaves and temperatures • Bushfire • Prolonged periods of low wind, solar or droughts • Multiple and non-credible contingency events In achieving the above goals, AEMO has developed new capacity to simulate the power system using synthetic power system component traces, derived from either observed or simulated weather. These capabilities will be demonstrated in the extreme event case studies, and use inputs and insights predominantly derived from the ESCI Project, a federally funded collaboration between AEMO, BoM and CSIRO that is now complete[33]. The capability to simulate power system outcomes in response to synthetic weather is now sufficiently advanced to inform case studies but requires further testing and consultation before this capability may be considered for the reliability forecast, or other market modelling. While AEMO acknowledges the possibility of downstream impacts from climate change, including shifting populations and substantially different consumption patterns due to societal disruption, these are not currently explored in scenario narratives, could be extremely difficult to quantify and remain excluded from modelling.

5.3.8 Renewable energy zones

AEMO questions:

- Do you have specific feedback on the proposed updates to the candidate REZs?
- Do you have specific feedback on whether REZ definitions should change further in the Export Superpower scenario?
- Do you have specific feedback on the proposed REZ resource limits?
- Is the addition of a resource limit land-use penalty factor reasonable? Is the value proposed for the penalty factor reasonable, and should it be applied equally to all REZs?

[33] For further details, see https://www.climatechangeinaustralia.gov.au/en/projects/esci/.

- AEMO seeks stakeholders' views on the approach to REZ transmission limits for future build of REZs.
- AEMO requests stakeholders' views on the proposed approach to explicit incorporation of system strength remediation cost estimates in the analysis.
- Do you have specific feedback on the proposed transmission expansion costs for use in the Export Superpower scenario, noting the different objective of connecting to ports rather than city centres?
- Do stakeholders have any other suggestions for representation of inter-related constraints across REZs?
- Do you have any feedback on the proposed values of the REZ transmission modifiers as a result of interconnectors or inter-zonal augmentations, and the REZs they apply to?
- Do you have any specific feedback on proposed connection costs for individual REZs, including the specific system strength remediation costs when applicable?
- Do you have any specific feedback on proposed regional-based connection costs?

Feedback received	AEMO response
On updates to candidate REZs: **Energy Estate** and **Central Queensland Power** expressed strong support for the inclusion of the Banana REZ in Central Queensland, citing a number of reasons other than green hydrogen export ports, such as proximity to existing grid infrastructure, strong wind and solar resource, and local loads. **Central Queensland Power** further suggested that the rationale for establishing the Banana REZ should include meeting anticipated early retirements of coal power stations in Central Queensland, and meeting the strategic need to decarbonise the existing load in Gladstone. They also argued that it is unreasonable for renewable generators to bear the cost associated with grid augmentation required to supply Gladstone load, following the retirement of Callide B and Gladstone. **Energy Estate** strongly supported the designation of the Hunter REZ, listing a number of reasons such as good solar resource, reasonable to strong wind resource, industrial land and pumped hydro opportunities. **Energy Estate** also suggested that the Central-West Orana REZ could be extended to the south, to capture additional wind resources and additional pumped hydro opportunities. This would	AEMO welcomes the support for inclusion of the Banana REZ in the 2022 ISP. For New South Wales REZs, AEMO has adopted the geographic definition of REZs advised by the New South Wales Government[34]. The Southern NSW Tablelands REZ will not be modelled because it is not part of the New South Wales Electricity Infrastructure Roadmap and it was not developed in the 2020 ISP. The NSW Government is in the early stages of planning the Hunter-Central Coast and Illawarra REZs, as set out under the NSW Electricity Infrastructure Act 2020. At this time, these REZs are not modelled because they have not been geographically defined. AEMO has added Offshore Wind Zones (OWZs) in locations where offshore wind projects are being investigated – including Illawarra Coast and Hunter Coast. The details of other REZs and OWZs are specified in the IASR. Importantly, in addition to REZs, AEMO's modelling also assesses the case for development of renewable generation into areas outside of REZs, including areas of the network with lower quality resources. While these parts of the network are not defined as REZs due to their poor resource quality, VRE development may still proceed for other reasons. For these areas, shadow resource limits, generator capacity factors, and network limits are outlined in the Assumptions Book. This process ensures the capacity outlook modelling the ISP considers the optimal trade-

[34] New South Wales Government. *Renewable Energy Zones*, at https://energy.nsw.gov.au/renewables/renewable-energy-zones.

Feedback received	AEMO response
allow it to capture existing and growing industrial loads, aligning the development of VRE with loads. **MUA** supported AEMO's inclusion of offshore wind in Gippsland, but argued that it is arbitrary to exclude other potential coastal areas and not an accurate reflection of offshore wind in the NEM. **MUA** opposed removing the Southern NSW Tablelands REZ, instead suggesting that it could be shifted to include Illawarra and offshore areas. Similarly, **EA** considered that the removal of the REZ seems inconsistent with the number of operational wind farm developments in the REZ, and an earlier description of its high quality wind resource.	off between development of high-quality renewable resources in REZs with associated network build, compared to developing lower quality resources in areas with spare network capacity.
On REZ definitions in the Hydrogen Superpower scenario: **Energy Estate** argued that REZ definitions should be aligned with the development of Renewable Energy Industrial Precincts. There is significant overlap between these and the ISP suggestions for green hydrogen candidate ports. The potential growth of demand around these load centres should be considered in the ISP. **MUA** argued that the proposal to build transmission from inland REZs to ports in the Export Superpower scenario further supports the rationale for offshore renewable energy resources. They highlighted that the need for offshore wind is clearer in the Export Superpower scenario, where AEMO aims to expand REZs beyond resource limits; in this scenario, more generation capacity would be built near ports, to be used for hydrogen exports. **ENA** stated that REZ developments should only be directed by the Export Superpower scenario where domestic customers are the direct and primary beneficiary of the investment, arguing that ISP investments in hydrogen for export industries should not be subsidised by Australian customers.	Renewable Energy Industrial Precincts were proposed ahead of the federal budget, which subsequently included funding for preliminary development of four hydrogen hubs. A range of potential sites were noted in the statement, several of which align with the ports being considered in the ISP for hydrogen export. The ISP has a broad range of REZ sites that have been identified. The ports that were suggested in the consultation were also identified on a multi-criteria basis, one of which was good access to renewable energy. It is possible that there will be additional demand growth around the locations where electrolysers are eventually located, over and above that needed for the hydrogen exports. The approach taken to co-locate the new "Green Steel" manufacturing near the export hydrogen electrolysers is intended to capture that synergy where load growth may centre around hydrogen hubs. AEMO agrees that the modelling of offshore wind should be expanded in all scenarios. In response to submissions, AEMO has added Offshore Wind Zones (OWZs) in locations where offshore wind projects are being investigated. The proximity of potential export ports to OWZ may result in additional incentives for OWZ development in the Hydrogen Superpower scenario than over other scenarios – the modelling for the draft ISP will assess this as part of the optimisation.
On REZ resource limits: **Walcha Energy** suggested that assumptions for the New England REZ should be amended to show more wind potential than solar, stating that 1,000 MW of solar and 2,000 MW of wind can occur with little curtailment. They also suggested that early REZ development should focus on areas with strong wind resources, given the level of solar PV DER investment occurring elsewhere. **Walcha Energy** also noted evidence for the potential of 3,940 MW of wind development in the New England REZ from the Walcha Plateau, and with other proponents in the REZ, suggested it would be prudent to plan for 10,000 MW of renewable energy and pumped hydro generation in the area.	Resource limits allocated to the New England REZ allow for up to 7,400 MW of wind, and 3,400 MW of solar to potentially be constructed, which broadly aligns with the Walcha Energy feedback. By adopting a land-use penalty factor, these limits could be expanded further. The 2022 ISP will also allow optimisation of wind and solar resource diversity to optimise use of REZ transmission capacity. AEMO noted the feedback on social license and impact on environment and community as the amount of renewable generation planted within a REZ increases. Following further discussions with interested parties who specialise in costing social license aspects, AEMO has concluded that it is appropriate to continue to utilise the proposal described in the 2021 Draft IASR, which is to include a land-use penalty factor (which represents social license costs). This is on the basis

Feedback received	AEMO response
Star of the South argued that the current resource limit methodology seems to ignore social licence caps on future renewable build-out. **Future Eye** similarly noted that AEMO doesn't consider social licence well, and that acceptance of large infrastructure by the community is critical in delivering it. **Energy Estate** and **Walcha Energy** suggested that social licence and land-use assumptions should be accounted for more when assessing the viability of REZs and new infrastructure, citing risks of delays and impacts on costs of not having community buy-in. **Walcha Energy** further argued that assessing the viable density of renewable development via multi-criteria analysis is not realistic, and the focus should be site-specific with due attention to density, distance and views from residential areas and individual landholders. **GE** observed that regional pumped hydro limits seem conservative relative to ANU studies, with IASR assumptions representing, on average, less than 1% of ANU's potential capacity.	that these cost aspects will be further explored and minimised as part of later regulatory investment test investigations, for example in investigating / consulting on transmission corridors and actual routes. Regarding pumped hydro, AEMO considers the pumped hydro resource limits reasonable for the cost assumptions applied for pumped hydro which are from the Entura report. Although more capacity may be technically possible, this would likely be at a significantly higher capital cost than what has been assumed.
On land-use penalty factors: **MUA** supported the proposal to add a land-use penalty factor if REZ resource limits are allowed to increase. **Walcha Energy** argued that a land-use penalty for the Export Superpower scenario is not appropriate and not required, instead suggesting that more and differently sited REZs should be developed for this scenario.	AEMO welcomes the support for the proposal to include a land-use penalty factor which includes social license cost. This proposal, as described in 2021 Draft IASR, will be implemented in the 2022 ISP. AEMO acknowledges that REZs may play a larger role in the Hydrogen Superpower scenario, but considers that REZ candidates should be consistent between scenarios. The addition of new REZs will likely be further away from the existing networks and ports, meaning a higher network cost.
On REZ transmission limits, expansion costs and remediation costs: **Energy Estate** commented that coal-fired power stations will retire well in advance of their scheduled retirement dates. This means that REZ transmission limits don't give the correct signal, as they are based on the coal retirement schedule. **GE** noted that pumped hydro has the ability to smooth output within a REZ, enabling better utilisation of the transmission network. Pumped hydro is also synchronous, meaning it would provide system strength and inertia in both pumping and generating modes, reducing grid remediation costs. **GE** stressed that in order to achieve optimal system design, it is necessary to consider these benefits in addition to the pure storage function that pumped hydro serves. Failure to do so	AEMO considers that the approach to developing transmission limits is appropriate and are not based on coal retirement schedules. REZ transmission limits are developed through network studies taking onto account existing generation. The retirement of coal and other generation is considered when assessing available headroom for new generation within REZs. AEMO notes that pumped hydro benefits to provide system strength, inertia, and smoothing is considered in the ISP. Please see section 4 of the ISP Methodology[35]. Regarding the basis of expansion costs components, please refer to section 4 of the 2021 Transmission Cost Report[36] which describes in detail the costing basis of sub-regional network augmentations, REZ network augmentations, generator connection, and system strength remediation costs.

[35] AEMO. *ISP Methodology*, at https://aemo.com.au/en/consultations/current-and-closed-consultations/isp-methodology.

[36] AEMO. *2021 Transmission Cost Report*, at https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

Feedback received	AEMO response
would understate the transmission limits of REZs whose wind and solar potential is complemented by pumped hydro. **EA** considered that AEMO should adopt a pragmatic approach to REZ transmission expansions, system strength remediation and other connection cost sensitivities. They also suggested that AEMO should outline the basis of the expansion cost component more clearly, in particular for geographically remote REZs where, for example, a locational uplift is warranted.	
On REZ transmission modifiers as a result of augmentations: **EA** stated that it is not clear what methodology was used to calculate how various network augmentations will impact on REZ transmission capacity. It is also unclear whether the expansion will impact on the need for increased system strength remediation. With an increasing trend of issues associated with system strength and voltage control due to large intermittent power stations, EA suggested that AEMO needs to better reflect how this impacts the market when considering REZ developments' interactions with interconnectors. EA also suggested that as part of the preparatory activities for New England REZ, TransGrid and AEMO should advise more specifically whether the network expansion option will be able to accommodate a notional extra 6,000 or 9,000 MW of capacity. **Walcha Energy** suggested that the schedule for grid augmentation is too late, particularly in the New England REZ, due to assumptions on thermal retirements. They argued that least regret transmission projects to connect priority REZ areas should be initiated immediately, as three year's notice of closure is insufficient to facilitate the establishment and connection of large-scale renewables needed to replace fossil fuels.	Section 2.3 of the ISP Methodology[37] describes how REZ network capacity is calculated. It is important to note that these are validated through the engineering analysis as also described in this section. Regarding the impact of expansion impacting the need for system strength, remediation depends on the type of network expansion. REZ network expansion options typically reduce the network impedance, which assists with system strength, however this is offset as VRE displaces synchronous generation. The system strength remediation is explicitly costed as described in section 5.2 of the 2021 Transmission Cost Report[38], and the approach used to calculate the system strength requirements is described in section 4.2 of the ISP Methodology. In respect of the suggestion from Walcha Energy, AEMO notes that the current frameworks for the ISP lead to a schedule for grid augmentation that is co-optimised with generation within the ISP models. This approach considers the lead-time for network augmentation and the assumptions on retirements provided by generators. The approach does not cover commercial decisions to dynamically alter operation, such as mothballing or other approaches. As a result, AEMO attempts to, where practical, assess the risks in relation to timing of major actionable ISP projects through scenarios and sensitivities, and where justifiable, incorporate staging and allowance for early works, to better manage these risks.
On group constraints across REZs: **Energy Estate** suggested that NSW constraints should be grouped, in view of the size of these REZs, and the need to plan for the retirement of NSW coal fired generation as well as service large energy users in Newcastle / Tomago and Sydney.	NSW is modelled in the capacity outlook model in four sub regions: North NSW, Central NSW, Southern NSW, and Sydney/Newcastle/Wollongong. These sub-regions provide a more effective representation than group constraints for REZ and have been implemented to improve the modelling of NSW coal retirements and servicing Sydney load.

[37] AEMO. *ISP Methodology*, available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/isp-methodology.

[38] AEMO. *2021 Transmission Cost Report*, available at: https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

Feedback received	AEMO response
Other feedback on REZs: **MUA** suggested that the selection of REZs should be revised on the basis that it includes offshore wind. The scoring system should then be overhauled to properly consider offshore wind, clearly distinguishing it from onshore. **MUA** also suggested that temperature and bushfire risk for onshore and offshore portions of REZs must be modelled separately. **ENA** sought clarification on what is assumed in the base case regarding REZ developments driven by other parties (e.g. state-based policies) and not based on the ODP. **Walcha Energy** suggested that the inclusion of priority REZs would be the appropriate place to consider state-based emissions targets yet to be legislated and should drive the Central scenario. **Walcha Energy** also proposed that transitioning to Priority REZ planning will mitigate the current problem of generators setting up in sub-optimal locations to connect to existing transmission. They suggested that more consultation between priority REZ planners and ISP grid planners is needed where priority REZs have much greater prospective generation capacity than is needed for interconnection.	AEMO now includes Offshore Wind Zones (OWZs) to represent likely points where offshore windfarms could connect to the main grid. These are based on areas of current interest from offshore wind developers. AEMO will consider bushfire risk in the ISP through climate case studies, as discussed in section 5.3.7. AEMO has described the assumptions on what state-based policies are included in each scenario in Section 3.1 of the 2021 IASR.

5.3.9 Network modelling

AEMO Questions:

- Is the proposed zonal model a reasonable representation of the network, focusing on the most critical cut-sets? Are there any additional zones which should be considered (and why)?
- For each ISP zone, is the nominated Zonal Reference Node appropriate?
- Do you have any specific feedback on the existing inter-zonal transfer capabilities? For capacity outlook modelling, if notional transfer limits between the zones were represented for several different demand conditions (rather than just maximum demand), what would the most relevant demand conditions be?
- Do you have any specific feedback on the treatment of anticipated transmission projects in the ISP?
- Do the augmentation options for the inter-zonal model listed above capture a good spread of credible options?
- Is the evolution into inter-zonal augmentation options from inter-regional options appropriately defined?
- Do you wish to provide views on transmission cost estimation ahead of the planned engagement, or suggestions for these upcoming engagements?

- Is there any specific feedback on the treatment of costs and options developed via preparatory activities for inclusion in the ISP?
- Is there any information on non-network technologies or proponents regarding opportunities for competitive non-network investment?
- Given that non-network investments generally involve commercial arrangements with plant with multiple revenue streams, how should AEMO estimate their cost transparently?
- While AEMO will consult further on the approach to modelling loss factors in the *ISP Methodology* consultation, AEMO welcomes initial views on the approach that AEMO should take for loss factors, particularly as new transmission and generation is projected to be commissioned.
- While AEMO will consult further on the approach for modelling MLFs in the ISP in its consultation on the *ISP Methodology*, AEMO welcomes initial views on the approach that AEMO should take for new generation.

Feedback received	AEMO response
On sub-regional augmentation selections/options: **Walcha Energy** suggested that the point in candidate REZ identification relating to distance to the nearest transmission line should be reworded to "does not require excessive measures to meet power system security requirements". They also noted that AEMO's approach to REZ identification needs to be validated by cross-checking against early stage development proposals, not just committed projects. For the CNSW-NNSW zonal augmentation option, Walcha Energy welcomed the range of options considered, and suggested preparatory activities focus on development and connection of the Walcha plateau, and have regard to the social licence of an excessive concentration of power lines. They also noted several renewable energy hubs would be required for the Walcha plateau, 330 kV and 500 kV connections are required, appropriate sequencing of work developing the grid South of Armidale and suggested different options to manage the sharing of parallel grid paths. **Walcha Energy** suggested the sub-regional approach can work against State's approaches to Priority REZ development, can underestimate the overall capacity required, and do not include intrazonal works required. **Walcha Energy** queried the strategy for inter-subregional DC options, and contrasts the RIT-T process with the inter-subregional strategy, arguing the latter strategy is much higher level and considered vast sizes of options that don't have an identified need.	AEMO notes that the CNSW-NNSW augmentation options were designed by TransGrid through preparatory activities, and were costed by AEMO. If it becomes actionable, the specific design of a project can be refined through the RIT-T. More information on this option is available in the 2021 Transmission Cost Report[39]. AEMO is confident the sub-regional model will not underestimate the overall capacity required. AEMO also notes that all outcomes of the capacity outlook model are validated through power system analysis using PSSE® and time sequential modelling. AEMO notes that HVDC options are considered in the ISP. The actionable ISP framework is designed for a RIT-T to follow once a project is declared actionable and is required to investigate alternative technology solutions to satisfy the identified need in much more detail than the ISP.

[39] AEMO. *2021 Transmission Cost Report*, at https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

Feedback received	AEMO response
On transmission losses: **EA** suggested that AEMO continues with its intentions to consult further on the approach to modelling changing loss factor equations. They also requested for AEMO to consider full network modelling of forward-looking loss factors at some intervals over the outlook period to update and better reflect the likely loss factors that will apply to locational generation and load under some of the modelled scenarios. **Ausnet Services** had a specific comment on MLF assumptions. Since Snowy 2.0 will be located in the Southern NSW, far from the NSW regional reference node (Sydney West substation), its power injection or withdrawal will have an impact on the transmission losses and therefore, a marginal loss factor of 1 is inappropriate. **Powerlink** suggested that losses materially affect modelling outcomes, and that having interzonal loss flow equations will improve model accuracy. Powerlink also claimed that capacity constraints across zones are a more accurate representation of transmission capacity than the current group constraint method.	AEMO will be calculating losses between sub-regions in accordance with the ISP Methodology[40]. This allows equations to be derived to represent losses between the regional reference nodes to be calculated for any given flow level, for the present network configuration and for potential future network augmentations. AEMO agrees that a loss factor of 1 is not appropriate for Snowy 2.0. Given its relative proximity to Lower Tumut, AEMO considers it appropriate to shadow the existing Tumut 3 generation and pumping MLF, noting this will be slightly conservative if and when HumeLink is completed. AEMO agrees losses can materially affect modelling outcomes. In response to feedback, AEMO may undertake additional analysis to ensure any consumer benefits that arise from lower transmission losses are considered – see the ISP Methodology for further details and welcomes support and further suggestions on refinements to the approach to modelling losses.
On transmission limits/capability: **EA** requested for AEMO to clearly articulate what the notional transfer limit increase is for CNSW-SNW Option 1 (Northern loop) and Option 2 (Northern loop) separately. **EA** also requested for validation on how firm the augmented interconnector transfer capacities will be, as affected by system strength and other power system limitations in a world with very little synchronous generation after coal closures. Will the large number of expensive transmission projects actually deliver their claimed increases in transfer capability? **EA** noted that AEMO should consider the inclusion of a select set of system normal constraint equations to be applied in the capacity expansion planning to better reflect a wider range of interconnector transfer limits at times of peak demand as affected by semi-scheduled plant. **EA** expressed concerns with the deterministic representation of interconnector transfer capability adopted for the regional capacity expansion model. This matter is less about the transfer capacities at different demand levels, and more about the prevailing power system conditions, and particularly how intermittent renewables and dispatch conditions that impact transfers. As a starting point and to provide transparency, they suggested for AEMO to explain which constraints define the notional limits used to represent the worst-case approximation transfers. For example, the forward direction capability approximation from CNQ to GG is 615 MW – what	AEMO notes that the CNSW-SNW options have been prepared by TransGrid through preparatory activities. AEMO estimated the cost of these projects because TransGrid consider their cost estimate to be confidential. AEMO has moved from a single value for flow path transfer limits in the capacity outlooking model to three values which reflect different system conditions (see the ISP Methodology for more detail). AEMO considers this strikes the right balance of complexity and accuracy. AEMO does not place any additional firmness factor on transfer limits in the capacity outlook model. AEMO will endeavour to provide the significant constraints limiting flow in the Assumptions Book. AEMO notes that it includes thermal, voltage and stability constraints which are updated to reflect future system conditions are developed through power system studies, and included in the time sequential modelling to validate the representation in the capacity outlook model.

[40] AEMO. *ISP Methodology*, at https://aemo.com.au/en/consultations/current-and-closed-consultations/isp-methodology.

Feedback received	AEMO response
is this limit defined by and does AEMO place any additional firmness factor on these limits as part of the capacity expansion planning process? **EA** noted that other restrictions to investment timing and delivery of transmission transfer capacity seem likely to arise. For example, the current voltage stability issues arising and constraining flows between Victoria and NSW, with associated price impacts. AEMO's modelling appears to assume that power flows will be constrained only by relatively firm thermal limits and this should be revisited, particularly as non-thermal network constraints will become more common and less predictable with more renewable generation investment.	
On transmission costs: **ISP Consumer Panel** stated that the engagement does not meet guideline requirements and that the current approach adopted presents risk to consumers that actual costs will materially exceed estimates. **Star of the South** noted that the transmission expansion costs should be higher than 2020 ISP, based on Project EnergyConnect cost increases, TasNetworks' decision to use underground cables for onshore components of Marinus Link. **TasNetworks** stated that different methods are required to ensure transmission and generation costs are considered on an "equitable" basis, to ensure a least cost outcome is achieved. They stated that transmission costing is carried out to a higher level of certainty, compared to "modelled" estimates for generation, which are subject to different rates of return as private investments. **PIAC** expressed concerns with how AEMO will source costs for the database, what recourse stakeholders will have to query or dispute estimates, and how these estimates will be measured for accuracy. **MEU** mentioned that transmission costs need to be updated based on PEC and Western VIC augmentation projects. They also requested for further clarity on connection costs for different REZs. **EA** requested for AEMO to explain what appears to be an excessive cost for SQ-CNQ Option 1, along with an overly long build time, and what the next most critical constraint is once the mid-point switching station has been developed. **EA** requested validation on AEMO's adoption of only 1% of capital cost per annum for operation and maintenance costs (opex) of new transmission assets.	Updated transmission costs for future ISP projects have been developed using the Transmission Cost Database. This has been calibrated against recent completed projects, and larger advanced actionable project estimates from TNSPs, including Project EnergyConnect. As a result some costs may change, compared to the 2020 ISP, but this will depend on the specifics of the project. Projects undergoing the RIT-T and preparatory activities have been estimated by the TNSPs and reviewed by AEMO to ensure alignment – more detail is provided in the *2021 Transmission Cost Report*[41]. The ISP Consumer Panel considered in February that the engagement on transmission cost did not meet the guideline requirements. In response to this feedback, the April webinar on approach to risk in cost estimation was added to the engagement schedule. Compared to the previous webinar, this webinar was extended to ensure time for two-way discussion. An extra meeting was also scheduled with the Consumer Panel to discuss this topic. A total of three webinars were held as part of the *Draft 2021 Transmission Cost Report* development, along with a four week consultation with written submissions. AEMO considers that this engagement has met the guideline requirements. Cost estimates include allowances for risks on ISP (transmission) projects that are based on the AACE status of that project – refer to the *2021 Transmission Cost Report* for further details on this methodology, including the estimates and range of uncertainties adopted for projects when assessing in the ISP, and how estimates are prepared. Costs for the 2021 transmission cost database were prepared by GHD as the independent consultant from a range of sources including in-house data, past project data, and vendor quotes. In developing the transmission cost estimation methodology and transmission cost database, AEMO has consulted stakeholders, and provided a draft database on its website on 28 May 2021 for all stakeholders for review ahead of its finalisation. An updated Transmission Cost Database is provided with the final 2021 IASR.

[41] AEMO. *2021 Transmission Cost Report*, at https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

Feedback received	AEMO response
Energy Estate stated that new projects should not be saddled with transmission augmentation costs arising due to the retirement of coal fired power stations (such as reinforcements to increase thermal capability). This would lead to increased costs, as transmission augmentation costs are factored into the price needed to achieve an appropriate WACC. Delta proposed an alternative approach to assessing the risk of higher transmission costs by explicitly identifying cost ceiling over which a project would be infeasible.	Connection costs have been updated in the *2021 Transmission Cost Report*. The cost for SQ-CNQ Option 1 has been updated by Powerlink in the *2021 Transmission Cost Report*. The mid-point switching station only increases the stability limit - it remains the most critical limit. For each actionable ISP project in the ODP, AEMO performs take-one-out-at-a-time (TOOT) analysis to provide a guide as to the project's sensitivity to transmission cost variations – please refer Section 5.9.3 of the *ISP Methodology* for details. This provides an indicator of the transmission cost threshold which, if exceeded, would lead to this project no longer being beneficial, all other inputs remaining unchanged. AEMO is also proposing to extend this to network for REZ development. In response to feedback on the assumed opex for transmission investments, AEMO has reviewed recent revenue determinations, contingent project applications and RIT-Ts, and considers 1% to be reasonable for ISP purposes as the cost of major projects in the ISP are dominated by transmission lines rather than substations. AEMO applies opex costs consistently throughout the modelling horizon, whereas opex costs are realistically expected to start low and grow as assets age. AEMO notes that AER will review and approve network expenditure from one revenue period to the next, so only the efficient and prudent project costs are expected to materialise. AEMO acknowledges feedback in relation to who should fund network upgrades, but notes that the ISP is a whole-of-system optimisation process that does not allocate costs to specific parties. Feedback relating to funding of transmission projects should be directed to the ESB's Post-2025 Electricity Market Design initiative[42] or the AEMC's Coordination of Generation and Transmission Investment (CoGaTI) review[43]. Further detail on transmission cost feedback is included in section 5.4.
On transmission outages: **MEU** requested for clarity on outage rates, in particular Heywood, which was assumed to be higher than other interconnectors. **Ausnet Services** suggested for AEMO to include modelling of forced outage rates for all interconnectors	AEMO has sought to ensure that transmission outage modelling in the ESOO aligns with the NER3.9.3C definition of unserved energy (USE). The six lines selected to apply outage rates to represent lines that materially contribute to inter-regional transfer capacity, and have sufficient evidence of historic single credible contingencies and reclassification events to justify inclusion. Their materiality was judged given the role of the lines in connecting strong meshed segments of regional grids together, and the degree to which the application of constraints consistent with a single credible contingency on these lines impacted interconnector transfer limits.

[42] ESB. *Post-2025 Electricity Market Design*, at https://esb-post2025-market-design.aemc.gov.au/.

[43] AEMC. *Coordination of generation and transmission investment implementation*, at https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and.

Feedback received	AEMO response
EA requested for more information on the assumed outage rates for the Heywood interconnector. The FRG requested more information on weather dependent outage rates.	In response to feedback received in consultation, AEMO will implement outage rates calculated from events caused by bushfire reclassification, lightning reclassification and single credible contingencies only. Other reclassifications, which tend to be longer in duration, will be excluded in 2021 until further consultation can be undertaken to better include stakeholder perspectives on which outages should be considered in calculations. This includes a revision to the assumed outage rate on Heywood. All transmission forced outage rates are derived through observation, however some are constant throughout the year, and others vary throughout the year to reflect the likelihood of bushfires. For those that vary with the likelihood of bushfires, the rate is escalated consistent with a single climate scenario.
On non-network options: **Energy Estate** stated that more analysis needs to be conducted on the benefits of large scale non-network options, as there is a risk otherwise of transmission over-build **Energy Estate** also referred AEMO to a submission on compressed air storage technologies and mentioned solar thermal. Regarding the revenue modelling of non-network options, they encouraged AEMO to consider the cap and floor mechanism used in Europe for new infrastructure, and the approach taken for CopperString, where the underwriting of revenue is subject to certainty of a proportion of the other revenue streams.	AEMO's analysis in preparation of the ISP includes a robust assessment of both network and non-network solutions, which captures their relative benefits. AEMO must consider non-network solutions throughout the ISP process and is required to call for submissions for non-network solutions in relation to actionable projects identified in the Draft ISP. These non-network submissions are assessed and non-network solutions that are reasonably likely to meet a relevant identified need in the ISP must be considered in the subsequent RIT-T assessment in accordance with NER 5.22.12. In regard to revenue modelling of non-network options, AEMO's experience suggests that the cost, contract duration and performance can vary significantly between non-network options. Because non-network proponents often have multiple revenue streams, these parameters are difficult to predict. As noted in the Draft IASR, AEMO welcomes stakeholders to recommend non-network options for inclusion in the ISP, but also considers that opportunities can be provided at the time of the RIT-T – when there is more certainty on the timing and need for a project.
Other: The ISP Consumer Panel suggested that the transmission versus distribution trade-off is not adequately explored by AEMO. In particular, the optimising of investment at both the distribution level and transmission level so consumers have confidence that they are not paying more than necessary. The ISP Consumer Panel also suggested that there should be greater emphasis on exploring issues around the social, economic and environmental impact of new transmission infrastructure. CQP was supportive of detailed grid analysis around the Gladstone node, but they do not support nodal pricing, nor the imposition of network reinforcement costs on REZ developers associated with the inter-nodal flows, if they arise due to retirement of Callide B and Gladstone. They also stated that if regional nodal pricing were adopted (despite their opposition) the Banana REZ and Fitzroy REZ should be settled against the Gladstone node, not the Ross node.	While AEMO does not intend to model the distribution system as part of the ISP, AEMO, TNSPs and DNSPs are working to explore how plans to accommodate high penetrations of DER can be leveraged by AEMO to support power system operation and the development of the ISP. DNSPs will continue to use their knowledge and experience to make investment decisions on their networks, and in the longer term assist AEMO in incorporating that information into the ISP where appropriate. The ESB's DER integration program will continue to explore requirements to integrate DER. AEMO notes that the classes of market benefits that must be considered by AEMO in an ISP are provided in NER 5.22.10(c) and further requirements are contained in the CBA Guidelines. AEMO welcomes further feedback on additional classes of market benefits that should be considered by AEMO which satisfy NER 5.22.10(c). Regarding CQPs feedback on nodal pricing, AEMO is not proposing to implement nodal pricing in the ISP modelling, nor is it making comments on the allocation of costs to particular parties.

Feedback received	AEMO response
RES suggested that AEMO consider the inclusion of a greater diversity of transmission technologies, such as fixed-duration high capacity superconductive links, trialled in Europe. EA mentioned that AEMO should include the impacts of all NCIPAP projects in the input assumptions as they impact on improving interconnector transfer levels and treat these as anticipated projects. EA requested explanation on why AEMO assumes an economic life for new power stations that is much shorter than their technical lives, but does not appear to apply this concept for transmission project asset lives EA questioned whether the inter-zonal cut-set between CNSW and SNW should include Bannaby-Sydney West, Marulan-Avon, Marulan Dapto and Kangaroos Valley Dapto 330kV lines as currently defined, or whether it should probably include Bannaby-Sydney West, Dapto-Sydney South and Avon-Macarthur 330kV lines, noting that Tallawarra and all load and generation at Dapto is defined to be in CNSW not SNW. Specifically, they requested to confirm to what extent Tallawarra generation and Dapto load will influence the defined power flow on this 5,600MW cut set as the zonal representation diagram shows Dapto and Tallawarra to be in SNW. Walcha Energy suggested that AEMO should accelerate its schedule for grid development for the New England REZ and also NSW central grid development between Bayswater and Bannaby to deliver power to Sydney from the North, West and South to mitigate risks associated with early coal closures. They also suggested that the ISP needs to go to an additional level of granularity in relation to each of the large existing coal-fired units to assess the impact of potential closure on the system and ensure that the market signals for investment in new generation and infrastructure are able to be correctly assessed. Notes the impact of this on system strength and transfer limits.	The sub-regional model is used to help physically model important sub regional flow paths in terms of transmission limitations, but the ISP modelling will continue to implement the present regional pricing approach.

5.3.10 Other power system security inputs

AEMO questions:

- AEMO's proposed assumptions generally reflect a projected decline over time in commitment of synchronous generator units (typically in thermal power stations) as alternative energy sources are introduced in the NEM. Do you have any specific feedback on this approach?
- Do you have any specific feedback on the regional security assumptions?
- Do you have any feedback on using the inertia and system strength requirements as described on AEMO's website as inputs to the ISP?

Feedback received	AEMO response
On the commitment of synchronous generator units: **EA** noted that AEMO appears to be taking a simplistic regional view of current and future power system requirements, whereby the need for a minimum requirement of synchronous units to always remain online is removed (except in Tasmania) as new interconnectors are built and synchronous condensers are installed. EA requested further information on how the number of large synchronous units always online has been determined, how the threshold dates have been determined and why they are appropriate, and what the implied requirements are on the number and location of synchronous condensers.	In terms of unit commitment requirements in each region, the existing minimum system strength synchronous unit requirements will initially be modelled by ensuring the appropriate number of units are constrained on at all times. Post 2025, these unit commitment constraints are no longer enforced on the assumption that for these timeframes the existing system strength / inertia frameworks will allow for the efficient delivery of these system services. This is on the basis that these services may be able to be sourced from other providers, and will no longer be reliant on enforcing unit commitment. As the system evolves, and once detailed models are available, comprehensive studies will be required to improve the accuracy of operating requirements and limits advice. Outputs from these ongoing studies, including reviews such as the Engineering Framework, will be incorporated when available.
On regional security assumptions: **Hydro Tasmania** noted that Marinus Link would allow for increased FCAS transfers between Tasmania and the rest of the NEM, and this needs to be captured in AEMO's models.	AEMO does not intend to include FCAS costs/benefits in its cost benefit assessments for the 2022 ISP, as this modelling would significantly increase the complexity of the modelling, while FCAS represents only a small amount of the total system costs/benefits[44]. Furthermore, many generation technologies being considered in future development paths, such as battery storage, wind, solar and pumped hydro, have potential to provide FCAS at little extra cost.
On inertia and system strength requirements: **EA** requested confirmation that AEMO will calculate and report any fault level shortfalls measured against the locational 2020 minimum three phase pre- and post-contingency fault levels across the outlook period in each scenario, and in the case where a shortfall is not identified, what the absolute fault levels are. EA also requested confirmation that AEMO will calculate and report any inertia shortfalls measured against the 2020 Secure and Minimum requirements in each region across the outlook period in each scenario, and in the case where a shortfall is not identified, what the inertia trend is.	For the draft 2022 ISP, AEMO will assess potential future fault level shortfalls under the current system strength framework[45] and publish results in a similar format to the 2020 ISP. AEMO will also assess inertia projects in accordance with the Inertia Methodology[46] and publish results in a similar format to the 2020 ISP in the ISP supporting material. AEMO notes that there is a proposal for rule changes under consideration currently[51] to the existing system strength framework, to be effective from late in 2022. AEMO does not consider that the currently proposed changes will materially change the ODP or outcomes in terms of REZ and VRE development, and will rather support the timing and staging of that development. The introduction of a second standard (for efficient level of voltage waveform stability) may influence the timing and extent of infrastructure required for system strength to support REZ development in accordance with the ISP projections and as such is not expected to materially impact the ODP. AEMO understands that the intention of the change is to enable an efficient

[44] In accordance with clause 5.22.10(c)(3) of the NER, AEMO does not intend to incorporate benefits relating to FCAS because they are unlikely to materially affect the outcome of assessing development paths, and the estimated cost of undertaking the analysis is disproportionate given the level of uncertainty regarding future outcomes.

[45] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review.

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

Feedback received	AEMO response
	level of investment for system strength based on ISP projections of future IBR, so that such investments occur in timely manner. Once the rule changes are finalised later in 2021, AEMO will further consider any potential impacts when finalising the 2022 ISP.
Other feedback on power system security: **EA** requested for clarification on how AEMO has accounted for findings from the Renewable Integration Study (RIS) and its impact of inputs and methodologies. **Delta** requested that AEMO clarify what it sees as the role of coal in New South Wales in providing power system requirements, and that AEMO provides cost estimates of the provision of each of the Power System Requirements post 2025-26 for non-coal versus coal.	The ISP has integrated findings from the RIS into its engineering analysis. The RIS described the operational challenges to support 75% instantaneous penetration of IBR, and made recommendations on requirements to address those challenges. While the RIS maps out the operational steps to help realise the ISP projections, the ISP then integrates these into its ODP. This is described in Part F of the 2020 ISP[47] and the executive summary of the RIS stage 1.[48] AEMO considers that existing synchronous plant provides a variety of power system services including inertia and system strength. It is difficult to delineate between provision of power system requirements and energy services as a number of generator technologies (especially synchronous generators) provide these services inherently as part of their operation. The ISP will not be able to provide a detailed analysis of separated costs to provide each of the power system requirements. Rather, it will map out the optimal pathway taking into consider the overall system costs, including the engineering solutions that will meet the overall power system requirements to ensure that the system remains secure.
Engagement with DNSPs: The **ENA** recommended further engagement with DNSPs to undertake power system studies where appropriate, and also recommended further clarification on the nature of the data exchanged with regards to DER.	AEMO, TNSPs and DNSPs are working to explore how plans to accommodate high penetrations of DER can be leveraged by AEMO to support power system operation and the development of the ISP. DNSPs will continue to use their knowledge and experience to make investment decisions on their network and in the longer term, will assist AEMO in incorporating that information into the ISP where appropriate.

5.3.11 Gas modelling

AEMO questions:

[47] At https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf.

[48] At https://aemo.com.au/-/media/files/major-publications/ris/2020/renewable-integration-study-stage-1.pdf.

- Do you have any specific feedback on the inputs and assumptions documented for gas modelling in the Draft 2021-22 Inputs and Assumptions Workbook?

Feedback received	AEMO response
On gas demand and hydrogen: **Sligar and Associates** argued that gas is traded by volume at a specific pressure but utilized on a heating value basis and the addition of a proportion of hydrogen alters this linkage and needs to be considered. **Origin** argued that the assumption of 100% hydrogen gas networks by 2045 does not seem plausible as it would require significant asset replacement including for appliances and distribution networks. It would instead be more plausible to assume other green products, such as biogas and synthetic methane, are part of the mix. **ENA** requested clarification on whether inconsistency of gas demand projections and domestic demand of hydrogen is due to electrification of residential and commercial services.	The hydrogen content in the gas pipelines is a consideration that was included in the multi-sectoral modelling. The best information at present is that hydrogen is able to be injected into natural gas distribution pipelines up to 10% by volume without any adverse effects. With more research and testing, it is possible that this could be higher. However, the multi-sectoral modelling found that in some cases it was more economical to electrify residential gas demand, with hydrogen primarily finding an opportunity in the industrial sector. In all scenarios other than Hydrogen Superpower, the gas pipelines remain predominantly natural gas. It is only in the 2040s for Step Change, and late 2040s for Net Zero where the total energy content of hydrogen consumed by residential and commercial customers accounts for more than 15% of the total gas consumption. While the multi-sectoral modelling does not consider individual pipelines, it is reasonable to consider that there may be a move to hydrogen precincts, much like some of the projects under development at the moment. It is recognised that switching from natural gas to hydrogen would require replacement of appliances and replacement of at least some distribution infrastructure. Conversely, hydrogen consumption by industrial customers is assumed to be much more direct with hydrogen facilities directly connected to industrial precincts (either locally or via dedicated pipelines). This is not expected to be a blended gas. Even in the Hydrogen Superpower scenario, there remains a demand for residential and commercial natural gas throughout the modelling horizon. The roll-out of hydrogen precincts would be earlier and more ubiquitous, but would not replace all natural gas demand for all customers. By the end of this scenario, natural gas would only be available at specific locations. Natural gas for industrial purposes would still be delivered by transmission pipelines. The multi-sectoral modelling identified a growing role for bio energy particularly in non-road transport (particularly aviation) as well as some industrial processes. However, electrification was typically identified as the most economic solution when carbon emissions reduction was a material constraint. Regarding the gas demand projections and the domestic hydrogen demand, this is being addressed directly by the multi-sectoral modelling on a least-cost basis. The demand from natural gas has been modelled to be affected by a range of elements. Displacement by hydrogen, electrification and energy efficiency are all contributors to the reduction in natural gas. Therefore, it is not expected that natural gas would be entirely replaced by hydrogen.

Feedback received	AEMO response
On Gas modelling assumption: **EA** suggested that it will be challenging for the QLD/NSW interconnector and Hunter pipeline to be available from 2022-23. Similarly, the assumed start dates for the Narrabri field (2024) and Beetaloo basin (2025) were deemed optimistic by EA. EA clarified that on import terminals - Port Kembla and Crib Point are the only two credible projects to start by 2023, Newcastle and Adelaide are less likely to be starting by then based on their status.	The Draft IASR assumptions for the gas assets timing preceded the updates from the 2021 GSOO. The final IASR has updated the timing and status of these developments.

5.3.12 Hydrogen modelling

AEMO questions:

- Grid-connected hydrogen is proposed to only be modelled in the Export Superpower scenario; in other scenarios any hydrogen is expected to either be insignificant or produced off-grid. Does this give sufficient coverage?
- In the Export Superpower scenario, decarbonisation ambitions lead to transitioning gas distribution networks to 100% hydrogen by 2045. Do you have any feedback on this approach?
- In the Export Superpower scenario, domestic hydrogen consumption is approximately equal to export until 2040, at which point domestic demand is largely saturated and export becomes the dominant cause of growth in demand. Do you have any feedback on the suitability of this trajectory?
- Do you have feedback on the penetration of battery and fuel-cell electric vehicles in the scenario collection?
- AEMO has selected PEM electrolysers as the preferred technology in this scenario, due to decarbonisation targets (preferencing green hydrogen), higher levels of flexibility in the operation of the assets, and notable investment activity in the market. Do you have any information that may indicate this assumption should be changed?
- Do you have any feedback on the cost of electrolysers, the efficiency of electrolysers, or the rate of cost reductions projected into the future?
- The electrolysers are assumed to have a fixed minimum baseload of 4.5% of their total capacity, even when they are not producing hydrogen. Do you have information that may indicate this assumption should be changed?
- Nine ports are proposed as candidates for the 2022 ISP expansion to produce export hydrogen. Do you have feedback on these candidates and their suitability over other options for hydrogen hubs?
- Water availability near the candidate export ports has been screened. Do you have any feedback on the assumed classification of fresh water being likely to be available or unavailable or desalination being required? Information that could help resolve the water availability at ports would be highly appreciated.
- The cost of desalination is assumed to be $0.05 per kilogram of hydrogen based on Australia's National Hydrogen Strategy. This is a small contribution to overall cost, and it is proposed that the electricity demand would likely be immaterial in the scale of the Export Superpower scenario (when compared with electrolyser demand). Do you think this is an acceptable simplification?
- It is assumed that only a small amount of hydrogen storage will be required at the ports for operational uses, and as such, the cost associated with this storage is immaterial. Do you agree with this approach?

Feedback received	AEMO response
On Hydrogen scenario development: The **ISP Consumer Panel** considered that the analysis supporting the assumptions was high level and that much more information was required before any confidence can be placed in the scenario, given their view that the scenario had the potential to result in considerable stranded asset risk for consumers. The **ISP Consumer Panel** were also not convinced there was sufficient evidence to support the assumption in the scenario of a strong emerging export economy from 2030, nor the assumptions of a 10% blending domestically. **QEUN** supported that blending hydrogen into the gas network should be considered. QEUN also argued that growth in hydrogen demand is likely to be export driven, and assumptions on domestic consumption should be moderated as we do not know enough about the intentions of large gas consumers. **ACF** mentioned that in the Export Superpower scenario both coal and gas exports will contract well within the window captured by the 2022 ISP, which would otherwise result in overinvestment, especially in gas-related infrastructure. **Australian Gas Infrastructure Group** mentioned the assumption on hydrogen supply and infrastructure are broadly reasonable but noted they are likely to quickly change as the industry develops and services are offered to customers by AGIG's projects and others. **Origin** mentioned the domestic hydrogen consumption in the Export Superpower scenario is approximately equal to export until 2040, at which point domestic demand is largely saturated and export becomes the dominant growth driver. A more plausible assumption would be for domestic demand to be consistently lower but driven by export markets. In addition, domestic demand being saturated by 2040 is not internally consistent with the assumption of 100% hydrogen gas networks by 2045 as this would keep driving up domestic demand past 2040. **Australian Gas Infrastructure Group** supported Export Superpower scenario and suggested the recognition of a strong hydrogen domestic uptake without being driven by an export market. The current drivers for hydrogen in the domestic market largely reflect Australia's effort to reduce emissions at lowest cost, for hard to abate sectors like industries that have no alternative but to use gas, and to improve energy security. These goals are reflected by the various decarbonisation commitments and targets adopted and we see these drivers continuing in the foreseeable future. **Energy Estate** noted that it is quite likely that it will not be economic to convert electrons to molecules, and then transport them to be combusted, rather than electrify heat via heat pumps. However, if gas continues to be reticulated, then migrating to 100% hydrogen in the distribution networks is critical. **Energy Estate** also argued that the rapid growth of hydrogen would not only focus on export opportunities but also domestically. While they mentioned the domestic and export hydrogen	AEMO acknowledges that substantial uncertainty remains about the uptake of hydrogen. However, equally, a future with a substantial uptake of hydrogen could substantially change the future NEM. The scenarios are intended to provide a broad coverage of plausible futures and repeated feedback has indicated that hydrogen is credible enough that it needs to be considered. As outlined in the ISP Methodology, the relative likelihoods of each scenario, and thereby the impact on Actionable investments in the ISP, will be the subject of further stakeholder engagement (through the use of a targeted Delphi panel) in the second half of 2021, prior to publication of the Draft ISP. AEMO considered the level of inputs provided in the Draft IASR, and identified that additional bespoke modelling of the potential for hydrogen and electrification to support a decarbonising economy would improve the forecast scenarios. As outlined in the IASR, AEMO engaged CSIRO and ClimateWorks Australia to conduct multi-sectoral modelling of Australia's economy across scenarios with stronger decarbonisation ambition. The scenario-specific domestic hydrogen adoption has been informed by this least-cost modelling exercise, rather than assumption-driven as per the Draft IASR. AEMO engaged with the FRG on these draft outcomes prior to finalisation. In this multi-sectoral modelling, some level of hydrogen adoption was established to be cost-effective in all scenarios with explicit carbon emission reduction targets. The export hydrogen remained an assumption for the multi-sectoral modelling, considered appropriate given the linkage with other hydrogen-specific modelling, such as the Hydrogen Strategy. Domestic demand in the Hydrogen Superpower scenario also includes the growth of a "green steel" industry in Australia. and increasing fuel switching from natural gas to hydrogen for existing connections, rather than to electrification that is more strongly anticipated in other scenarios. This approach was taken considering the depth of feedback provided by stakeholders. Additional responses are: • Infrastructure investment in the gas network and coal transport systems are not explicitly considered in the ISP, however the GSOO will continue to assess the adequacy of existing and committed infrastructure to deliver the needs of gas consumers. As outlined in the ISP Methodology, the ISP may also validate the ability of gas networks to deliver gas in the scenarios, as appropriate given the modelled outcomes. • While the Hydrogen Superpower scenario presents a future with strong export potential, the other scenarios demonstrate a domestic role for hydrogen is possible, but uncertain, across the NEM regions. The 'Strong Electrification' sensitivity will be used to consider how sensitive actionable investments are to the maturing of electrolyser hydrogen production technology.

Feedback received	AEMO response
trajectories are reasonable, they considered to some extent that it is also possible for the scale of hydrogen growth in Export Superpower to occur under the Sustainable Growth scenario. **Energy Estate** also mentioned that if half of the bus transport fleet in NSW is replaced with hydrogen fuel cell buses, more than 200 MW of electrolyser capacity would have to be installed.	
On modelling hydrogen utilisation: **ENA** requested clarification on the role of gas and the potential for hydrogen to be used for electricity generation (or electricity storage). **EA** disagreed with some assumptions on the operation of hydrogen turbines. Some are: • On the flame behaviour of hydrogen which is very different to the fuels that gas turbines have been designed to operate on. Higher hydrogen mixes may involve a significantly higher risk of combustion oscillation and "flashback" (backfire). • On issues with NOx production from hydrogen combustion which again point to the need for redesign from existing plant. • On the capacity of more modern designs to accommodate a modest mix of hydrogen and natural gas (perhaps up to 20%) however we are not aware of evidence to support this. • On the new plant designs in development that could accommodate higher concentrations of hydrogen and even those that are most advanced have not yet reached commercial readiness (aside from some smaller, modular designs). **Energy Estate** argued that it is not reasonable to assume that only a small amount of hydrogen storage will be required at the ports for operational uses, and thus the cost of this storage is immaterial. This is why Pathway 3[49] should be the considered approach. Hydrogen storage is expensive. Hydrogen pipelines avoid additional catenary costs and provide buffer storage. It also mentioned that the demand for clean fuels for the shipping industry is not sufficiently taken into account. This will require storage at the relevant ports, which in many cases can be repurposed existing storage assets. **ENA** mentioned hydrogen storage potential is greater than what is assumed to be stored in the IASR. **Sligar and Associates** clarified that it is unlikely that small diameter/high pressure systems (which is what present hydrogen distribution systems are) will replace the existing large diameter,	In regard to potential role of hydrogen for power generation, AEMO has considered this generation type in the multi-sectoral analysis. The modelling found that hydrogen was not economic for the purpose of electricity storage/supply compared to alternatives. AEMO recognises that this outcome may be due to the relative coarseness of the model and the challenges in recognising the need for shorter-term capacity. As such, AEMO will continue to assess hydrogen as an option in the capacity outlook model (in the Hydrogen Superpower scenario only). EA's concerns are noted and AEMO understands that there is still research and development to be undertaken, accordingly AEMO assumes that hydrogen-powered turbines will not be available before 2030 (in the Hydrogen Superpower scenario). AEMO has revised the assumptions on the capital cost of hydrogen turbines in response to this feedback. AEMO has applied an uplift to the capital cost of hydrogen turbines (over gas-fired OCGTs) that is equivalent to the uplift applied for hydrogen reciprocating engines compared to gas reciprocated engines in CSIRO's GenCost study. AEMO is modelling gas-hydrogen blending into the distribution network and not the transmission network. The majority of scheduled GPGs are connected to the transmission network. In regard to hydrogen storage, AEMO recognises that additional storage may be developed, yet most of the identified demand is industrial, transport or export focussed. Consequently, the demand is projected to be fairly constant throughout the year – meaning that small amounts of storage would be required to smooth variable supply on a short-term basis. In terms of final design, it is recognised that pipeline compression may provide some storage, export facilities may also provide some level of storage. For the purpose of this modelling, it is still considered sufficient to manage the variable demand with monthly rather than annual operational targets. The time sequential model will be given monthly targets and therefore the inherent storages would only need to manage shorter-term variances. It is assumed that sufficient large-scale hydrogen storage will be available to manage the seasonality of hydrogen demand, such that consistent monthly targets for production will apply across the year. The export monthly profiles will be similarly consistent throughout the year, reflecting the current behaviour of LNG exports.

[49] Pathway 3 assumes the hydrogen production facility is close to the energy source, transporting hydrogen to the demand. Pathway 2, the pathway selected by AEMO, transmits the electricity to the electrolysers that are co-located with the demand.

Feedback received	AEMO response
low pressure pipe system by 2045. As for hydrogen storage, the proposed Kawasaki hydrogen tanker has a capacity of 40,000 cubic metres of liquid hydrogen. **Origin** mentioned that AEMO should also consider the potential needs of the different types of downstream processing, such as ammonia or liquefaction plants. These plants could add a significant amount of inflexible load to the grid, which should be captured in inputs and assumptions. **Origin** argued the cost of storing hydrogen at ports is likely to depend on the downstream processes used. Some downstream processes may have more significant storage needs to capitalise on the responsiveness of the electrolysers. **MMTech** suggested that hydrogen developments should be encouraged in respect of VRE storage from 2-16 hours. Gas usage will decline if mid-term VRE storage can be developed using hydrogen. **MMTech** also argued that green steel developments may not be a consideration until 2030. **ElectraNet** welcomed the hydrogen scenario and noted that exports should not be at the expense of storage technology serving the electricity network.	Regarding the selection of Pathway 2 rather than Pathway 3, the key driver behind that decision was the need to produce modelling that is representative of generic opportunities. Without clear information on water availability, it is reasonable to assume that coastal facilities will be able to use desalination – yet if the development was inland, pipelines would need to be constructed for both water and hydrogen. AEMO recognises that this is an area of uncertainty and will look to explore it further in future modelling efforts. AEMO agrees with Origin's suggestion that downstream processing plant are a material consideration. While there are a range of transport options, the nature of AEMO's modelling does not allow for all options to be explored in detail. AEMO is assuming conversion to ammonia as the export option. There is a common consensus across the industry that this is one of the cheapest, most effective, and most dominant ways of exporting hydrogen, especially since transport of ammonia is well understood. Green steel is only considered in the Hydrogen Superpower scenario and is not forecast before the 2030s. Regarding the opportunity for use of hydrogen in shipping, that is recognised as a potential source of demand and such opportunities are considered to be part of the "export" load in the Hydrogen Superpower scenario.
On hydrogen production technology: **ENA** suggested the production from steam methane reforming (or coal gasification) combined with CCS to be consider as an option. **Energy Estate** agreed it was reasonable to assume PEM electrolysers as the preferred technology. **Origin** clarified that both proton exchange membrane (PEM) and alkaline technologies are likely to play a role, with the latter more likely to become the predominant technology in the future. **ENA** agreed PEM electrolysers appropriate for ISP but suggests gas rich regions will produce blue hydrogen and could reduce renewable electricity required for the scenario.	The multi-sectoral modelling did assess the relative merits of steam methane reforming (SMR) with or without carbon capture and storage (CCS) for hydrogen production, as well as PEM and alkaline electrolysers. CSIRO's detailed report provides more context on the scale of each technology deployed. For ISP and ESOO purposes, AEMO models the production from electrolysers and assumes that all electrolysers will utilise PEM technology. Any hydrogen produced by SMR will not impact the power system analysis performed within the ISP or the ESOO, but may be considered as a source of gas demand in the GSOO.
On Electrolyser capital costs: **Energy Estate** clarified the current full electrolyser system cost is closer to $1500/kW with $1000/kW expected by 2025. It is reasonable to project electrolyser costs at 2030 as being $750/kW. Electrolyser efficiency is likely to be around 55kWh/kg by 2025 and close to 50kWh/kg by 2030. **ElectraNet** urged caution on costs of hydrogen. It should be benchmarked against international information (such as from NREL).	AEMO notes that there is substantial uncertainty on the cost of an electrolyser. Much of this uncertainty is related to what is included in the cost and the scale of the plant. AEMO's costs include both the electrolyser stack and the balance of plant and are intended to represent industrial-scale electrolyser projects. The multi-sectoral modelling included hydrogen uptake based on a cost profile and GenCost learning rates, with consideration of the high degree of uncertainty captured across scenarios. The resulting hydrogen production demonstrates this variance, with much greater domestic production in the Hydrogen Superpower scenario (which has the greatest technology cost reductions, as well as high emissions reduction requirements) than in other scenarios. The

Feedback received	AEMO response
ENA argued that the production cost in the Technology Roadmap will require cost reductions in electrolysers, increased utilisation rates, and cost reductions of renewable energy generation. The cost of the balance of plant (and its potential reduction over time) need to also be considered. **Hydro Tasmania** argued that hydrogen capital costs are inherently uncertain, due to the limited maturity of the technology. The uncertainty is likely to be homogenous across the regions and the regional cost factors need to be reviewed.	Hydrogen Superpower scenario has similar system costs to those recommended by Energy Estate from 2030, although the earlier years remain higher, with the 2025/26 capital cost at $1179/kW. While current prices are substantially higher, technology costs are assumed to fall rapidly. AEMO recognises that reducing costs of hydrogen production to $2/kg (or below) will require significant cost reductions. AEMO's scenarios vary accordingly to cater for faster and slower achievement of this goal, noting that the multi-sector modelling indicated that a price less than $2/kg is needed to underpin significant commercial deployment.
On Hydrogen electrolysis input requirements: **Energy Estate** assumed a fixed minimum baseload of 4.5% of total capacity for electrolysers of the size developed to date. As the size increases, this will reduce but probably not lower than 1-2%. **Origin** clarified the assumption that electrolysers have a fixed minimum baseload of 4.5% of total capacity appears to be low – 10% would be a more plausible assumption for alkaline electrolysers. **ENA** notes Hydrogen can play a major role in stabilising the electricity grid. As grid-connected electrolysers, it can be used as a variable load that could be switched off in periods of high demand and switched on in periods of low demand – similar to large scale batteries. The non-grid connected hydrogen production for domestic use could subsequently be used in fuel cells to generate electricity. **Energy Estate** found the assumption on the cost of desalination reasonable. **ENA** mentioned the water required for hydrogen is appropriate, as is the assumed costs for desalination. **Origin** argued AEMO proposes to screen "fresh water" availability. It is not clear if "fresh water" would meet social licence requirements. Sustainable water (e.g., through desalination) would be a more appropriate measure. **QEUN** argued that AEMO should not assume water will be always available at points of production.	Noting that proton exchange membrane (PEM) electrolysers are assumed as the primary technology to meet production needs in the ISP modelling, AEMO concludes that the baseload assumption is not unreasonable given stakeholder feedback. Scale may reduce the baseload percentage, but any installations of alkaline instead of PEM electrolysers would work to increase the baseload percentage. The key outcome is that some level of baseload is deemed appropriate. While the quantum of hydrogen production will be entered into the Capacity Outlook model as a production constraint, the way that demand is met will be determined by the optimisation of the model, considering the resource availability, proximity of VRE to export ports and domestic facilities, and the cost of grid augmentations to deliver this energy. This approach is provided in more detail in the ISP Methodology. AEMO acknowledges that the consideration of water supply is a coarse assumption. AEMO is not considering adding additional electricity requirements and cost to consider water sourced from desalination, and is not able to model water requirements more quantitatively than the initial development site screening. Considering the expected low-likelihood of the Hydrogen Superpower scenario relative to other scenarios, AEMO considers this reasonable given the small influence that this may have on actionable investments.
On hydrogen production locations/port selection: **MUA** supported the selection of the 10 candidate ports. They note that almost all are adjacent to offshore wind resources.	AEMO's inclusion of Offshore Wind Zones provides greater potential for local electricity production near to the export ports, although broadly AEMO continues to utilise Pathway 2 (rather than pathway 3 as indicated by MUA), given the increased flexibility that transmission

Feedback received	AEMO response
MUA requested AEMO to consider Pathway 4 instead of 3. In pathway 4, electricity is generated near the hydrogen production facilities and offshore wind can facilitate this option. **ENA** argued that hydrogen could be produced in the REZ and then delivered to the port, rather than being produced at port (location of electrolysers). **Energy Estate** commented on the suitability of ports selection but mentioned there are a number of contingent issues and considerations that need to be considered to ensure there aren't operating constraints at the identified port locations. These are: space at the port for infrastructure, transmission infrastructure connection, co-location of large domestic use (existing/new), environmental protection, water, and safety. **Energy Estate** also mentioned that Port Kembla is likely to have a suitable water supply. More generally, with large scale hydrogen generation it will be important to consider where the RO (*AEMO interprets this acronym as 'Reverse Osmosis'*) waste stream will go, with availability of adequate recycled water supply becoming more important. **Energy Estate** also argued that the REZs definitions should be aligned with the development of Renewable Energy Industrial Precincts. There is significant overlap of these with the ISP suggestions as green hydrogen candidate ports. The potential growth of demand around these load centres should be considered in the ISP. They argued therefore that transmission costs in this scenario should not only focus on candidate ports but also areas of the NEM where there are existing or potential domestic industries which are major hydrogen users - such as the Queensland Nitrates plant at Noura in Central Queensland. **ENA** argued that REZ developments should only be directed in this scenario where domestic customers are the direct and primary beneficiary of the investment, and ISP investments for hydrogen export industries should not be subsidised by Australian consumers. **MMTech** argued that insufficient acknowledgement has been made in regard to water availability for hydrogen production. Development options should focus on North QLD (Port of Townsville) and Tasmania, noting the latter will have a freight disadvantage into Asia of up to $7 per export tonne. **Shell Energy** recommended AEMO to consider the possibility that some Hydrogen electrolysers may be commissioned outside the current NEM grid infrastructure as standalone projects.	may deliver to broader NEM consumers, than dedicated hydrogen pipeline facilities as well as the potential network infrastructure required to service the NEM itself. The breadth of feedback on this topic highlights the importance for continued consideration in AEMO's modelling suite for future work. AEMO's inclusion of hydrogen as described in the ISP Methodology is considered the most reasonable balance of complexity and accuracy for the 2022 ISP, particularly given the high uncertainty of export facilities on ISP's ODP. In future ISPs, as hydrogen production demonstrates signs of growing maturity and deployment, AEMO will consider what added complexity may be captured by AEMO's models, or within supporting models such as the multi-sectoral modelling conducted by CSIRO. Regarding the recommendation that some electrolysers be considered to be off-grid, it should be noted that in all scenarios, hydrogen can be produced by electrolysers and/or other technologies. The Hydrogen Superpower scenario is intentionally exploring a future where hydrogen plays a major role in the NEM.
On the use of hydrogen in transport: **ACF** argued that hydrogen will not outcompete battery EVs for most light vehicle and bus applications. Hydrogen transport may play a larger role for long haul transport, and battery electric vehicle (BEV) uptake is unlikely to plateau due to the uptake of hydrogen fuel cell vehicles.	As outlined in CSIRO's forecast of electric vehicles, BEVs are more likely to be the dominant technology in the electrification of transportation, particularly in the light-vehicle sector. CSIRO agrees that there is greater suitability for hydrogen in heavy and long-distance transport vehicles, replacing existing diesel vehicles. It is plausible that FCEVs reduce in costs, and may play a notable role in the transport fleet, with the Hydrogen Superpower retaining the largest hydrogen adoption in transport.

Feedback received	AEMO response
Hydro Tasmania also argued that hydrogen fuel cell electric vehicles (FCEVs) would remain more segmented to heavy long-distance transport. **Origin** argued that higher levels of electrification are likely to drive hydrogen growth, and BEVs are likely to complement hydrogen penetration. AEMO should not alter the BEV forecast as a result of hydrogen adoption, and they argued that the forecast of FCEVs appears high. **Australian Gas Infrastructure Group** mentioned IASR should consider the role of passenger and long-distance heavy haulage transport, the production of hydrogen to meet this demand, and the implications of the electricity network. **MUA** support the inclusion of hydrogen modelling. They note that ships and smaller vessels can be powered by hydrogen too.	AEMO considers this stakeholder feedback is relatively consistent with the 2021 EV drivers and inputs presented in the IASR.
On other Hydrogen feedback: **MMTech** argued that it would be useful to build up skills and usage protocols, best achieved via blue hydrogen. **ENA** noted the electricity price and utilisation will depend on whether the electricity is sourced on grid or off grid, and significant electricity storage issues need to be considered. **Australian Gas Infrastructure Group** claimed hydrogen represents the least cost pathway to achieving emissions reductions from natural gas, citing analysis by Frontier Economics in their "Electrification" scenario. **Australian Gas Infrastructure Group** mentioned grid connected electrolysers could potentially provide benefits to the electricity market in the form of FCAS, demand management and storage. Projects like HyP SA and HyP Murray Valley will help to demonstrate the potential value of these services for hydrogen production, renewable electricity generation and electricity markets. **ECA** argued that AEMO should consider who would pay for the massive investment in infrastructure that would be required to export the volumes of electricity and hydrogen contemplated by the scenario and what the implications might be for energy bills for households and critically, domestic businesses.	AEMO notes the feedback provided, and has not identified any necessary input adjustments in response. AEMO appreciates that there are a number of uncertainties and barriers to deployment before the opportunity for hydrogen production can be achieved. AEMO's scenario collection captures this uncertainty. Blue hydrogen and off-grid production may well play a material role in the future. In Net Zero 2050 there was a spread of technology choices in the multi-sectoral modelling, including electrolysis and SMR both with and without CCS. AEMO acknowledges the importance of the "who pays" question, but notes that the ISP is a whole-of-system optimisation process that does not allocate costs to specific parties. Expanded infrastructure to deliver for hydrogen consumers in this scenario will not be distinguished from infrastructure supporting other industrial processes, however it is unlikely that these extra investments will be Actionable investments given the high uncertainty of this scenario. Feedback relating to funding of transmission projects should be directed to the ESB's Post-2025 Electricity Market Design initiative[50] or the AEMC's Coordination of Generation and Transmission Investment (CoGaTI) review[51].

[50] ESB. *Post-2025 Electricity Market Design*, at https://esb-post2025-market-design.aemc.gov.au/.

[51] AEMC. *Coordination of generation and transmission investment implementation*, at https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and.

5.3.13 Other feedback

Feedback received	AEMO response
On the modelling horizon: **David Havyatt** stated that the modelling horizon should cover the period out until 2050.	AEMO can confirm the modelling will extend to 2050.
Scope of considerations in the ISP modelling: The **MUA** proposed that the ISP should also undertake more integrated modelling which considers the impacts on employment, education, health, etc., and that considerations should include just transition measures in the high decarbonisation scenarios. They also propose that the modelling should include the externalised social costs of the energy transition associated with coal replacement.	While AEMO recognises the potential for wider benefits and impacts as identified by the MUA submission, the ISP assessments are limited under the current regulatory framework. The classes of market benefits that AEMO must consider in preparing the ISP are set out in NER 5.22.10(c). These benefits do not include those associated directly with employment, education etc., nor are they able to take into account any consideration of a just transition associated with decarbonisation or coal replacement. The ISP does not attempt to make comparisons between the benefits and costs between scenarios themselves, but rather explores the costs and benefits of developments within each scenario. The ISP is not intended to outline whether a scenario is preferred, and therefore these potential impacts of more ambitious decarbonisation and/or earlier coal closures are not material to that assessment. Furthermore, an objective quantification of these cost components would be very challenging. AEMO is exploring the potential to understand the impact of employment bottlenecks and how these might impact the determination of the ODP.

5.4 Inputs and assumptions feedback in response to the *Draft 2021 Transmission Cost Report*

The *Draft 2021 Transmission Cost Report*[52] forms part of the 2021 IASR and was published on 28 May 2021. This section presents material feedback raised by stakeholders and AEMO's response to each matter. Feedback is grouped into the following areas:

- Feedback on transmission cost estimation process.
- Feedback on flow path augmentation and REZ development options.
- Feedback on generator connection costs.

[52] AEMO. *Draft 2021 Transmission Cost Report*, at https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

5.4.1 Feedback received on transmission cost estimation process

AEMO questions:

- Are there any factors not currently assessed that AEMO should consider in its method for estimating the costs of future transmission projects in the ISP?
- Are there any other aspects AEMO should consider for risk assessments when estimating costs of future transmission projects in the ISP?
- What, if any, modifications should AEMO consider to the Transmission Cost Database?
- Are there any other factors AEMO should consider in its approach to reviewing cost estimates submitted by TNSPs?

Feedback received	AEMO response
On risk allowances, estimate class and accuracy: **ENA** argued that as early ISP projects are based on desktop studies, it is not feasible for TNSPs to achieve AACE class 3 estimates for all options assessed under preparatory activities. They also noted that there needs to be a greater recognition of the need for appropriate levels of contingency to cover residual risks in large projects, and that the concept of almost no known risks and no unknown risks for a project such as PEC at PACR or CPA stage is unrealistic. **MEU** supported actionable ISP projects be developed to a class 4 or 3 estimate with a 20% premium to account for cost estimate accuracy asymmetry. **Shell and MEU** argued that more accurate class estimates are needed, as consumers would otherwise bear high costs. AEMO should require Class 3 for PADR, Class 2 estimates at PACR stage and Class 1 for projects seeking AER approval. MEU noted that AEMO had previously commented that they cannot impose an estimation accuracy as it is for the relevant TNSP. **MEU** noted that accuracy classification used by AEMO is different to GHD's. Shell requested clarification on the uncertainty range -15%/+45% versus ±30% used by AEMO. To improve asymmetrical accuracy, **Shell** suggested two approaches, using a more detailed assessment of costs (increase design work) or adjusting forecasts to above the mid-point range (adjusting with 40% premium). Shell also suggested adjusting costs estimate further to reflect AACE 80% confidence level. **Shell** noted it may be appropriate to use a high range cost estimate with asymmetric error margin which includes a lower accuracy with an error margin of ±10%. One TNSP noted that the use of a ±30% accuracy range for a Class 5 estimate is too narrow for some projects where the level of scoping is low, even with the proposed 15% unknown risk offset. **ENA** noted that TNSPs should review building blocks and attributes for future actionable projects.	The AER's Cost Benefit Analysis Guidelines[53] and their guidance note on the regulation of large transmission projects[54] do not prescribe the class or accuracy level of cost estimates throughout the ISP, RIT-T and CPA process. Based on feedback that has been received to this consultation, it is clear that there is a range of conflicting expectations on the appropriate level of cost estimate accuracy within these frameworks. AEMO considers that there would be value in having clear regulatory requirements for cost estimation accuracy in the ISP, preparatory activities, the RIT-T, the feedback loop and the CPA. The indicative class levels shown in the *2021 Transmission Cost Report* reflect AEMO's current understanding of levels that are typically applicable at each regulatory stage, which may vary across the TNSPs and across projects. Additional wording has been included in the report to reflect the AER's expectations outlined in their guidance note on the regulation of actionable ISP projects (i.e. that unknown risks should not be included at the CPA stage, and that TNSPs should undertake activities to identify all risks prior to submission of the CPA). AEMO acknowledges the proposed 'Material Change in Network Infrastructure Project Costs Rule Change'[55], which has not yet been initiated by the AEMC, and expects that this will provide a platform for ongoing discussion on the matter of cost estimation accuracy. In relation to feedback on risk allowances, the approach used by GHD in the Transmission Cost Database is based on the AACE classes and accuracies, with the accuracy selected within the AACE range as suited to this industry. The unknown risk allowance is applied as an offset, to shift the estimate above the original estimate, in order to make the cost accuracy range approximately symmetrical. Due to the large number of future ISP projects to be estimated, only concept level scoping is carried out on many of these. A select number are reviewed in more detail by the TNSPs, allowing screening level scoping with greater definition. AEMO has responded to feedback on the offset and accuracy for Class 5 estimates by splitting these into two categories to differentiate the projects which have been estimated at concept level (Class 5b) and those at screening level (Class 5a). Based on additional statistical analysis by GHD, a higher unknown risk offset of 30% and broader accuracy range of ±50% (covering 80% of estimates) is applied to Class 5b projects. Regarding the asymmetrical uncertainty range used for the original class 5 (now labelled 5a), GHD advised that AEMO apply an offset of +15% to the project cost and -15%/+45% accuracy range to make an

[53] AER. *Cost Benefit Analysis Guidelines*, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable.

[54] AER. *Regulation of large transmission projects*, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulation-of-large-transmission-projects.

[55] AEMC. *Material change in network infrastructure project costs*, at https://www.aemc.gov.au/rule-changes/material-change-network-infrastructure-project-costs.

Feedback received	AEMO response
	approximately symmetrical range of ±30% about the new higher mid-point. Further description can be found in the final report.
On environmental costs: **ENA, Moyne Shire and ResistHumelink** noted that environmental costs should be considered as part of the process, and also that these are volatile and only become well known at the development stage. **ResistHumelink** raised that the costs of undergrounding lines should be offset by the benefits including lower visual and environmental impact. They also stated that there are land-use conflicts between overhead transmission and modern agricultural practises that use drones and GPS to improve farming efficiency. **Moyne Shire** also suggested undergrounding of powerlines should be considered and the economic analysis include whole of life, not just initial capex and construction. This economic analysis should also include social, economic and environmental impacts of wind farms and consider the entire life cycle of infrastructure, including sustainable decommissioning of facilities.	The NER and AER guidelines define what AEMO is permitted to consider when developing an ISP. In accordance with these rules, AEMO considers the cost of construction, maintenance and operation of any network option, including compliance with laws, regulations and administrative requirements. Therefore, in relation to the cost of a network option, AEMO is only permitted to consider environmental and social impacts to the extent that they impact the construction, maintenance and operation of a network project. For example: • If a government requires a biodiversity or environmental offset[56] due to the impact of a network project, the cost of providing that offset will be incorporated into the project estimate. • If a project requires a new easement that impacts landowners, the cost of acquiring land will be incorporated into the project estimate. • If the route of a project needs to avoid an area of environmental concern, then the additional cost will be incorporated into the project estimate. • More information has been added to the 2021 Transmission Cost Report on the cost of underground lines (see section 2.5). Once a project becomes actionable in the ISP it enters the RIT-T, where the TNSP will refine network options and engage with non-network proponents to evaluate non-network options. There are further opportunities for stakeholders to engage at the Project Assessment Draft Report (PADR) phase of the RIT-T. In its recent guidance note on regulation of actionable ISP projects[57], the AER noted the need for TNSPs to engage with a range of stakeholders, including local communities, prior to submission of the Contingent Project Application (CPA). This allows consideration of options that minimise environmental and social impacts. Consideration of changes to regulations are covered by reviews such as the ESB's REZ Planning Rules[58] and the AEMC's CoGATI program[59]. Jurisdictional planning regulations and programs may

[56] An environmental offset is a measure that compensates for impacts on environmental matters on one site by securing and managing land at another site over a period of time. Management of land at the new site should replace any significant environmental matters which were lost.

[57] AER, Guidance note on Regulation of actionable ISP projects, March 2021, at https://www.aer.gov.au/system/files/AER%20-%20Final%20Guidance%20note%20-%20Regulation%20of%20actionable%20ISP%20projects%20-%20March%202021%20-%20FINAL%20FOR%20PUBLICATION%2812129318.1%29.pdf.

[58] ESB. *Renewable Energy Zones*, at https://energyministers.gov.au/reliability-and-security-measures/renewable-energy-zones.

[59] AEMC. *Coordination of Generation and Transmission Investment*, at https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and.

Feedback received	AEMO response
	also consider broader impacts – stakeholders are encouraged to take part in the relevant consultations. Decommissioning costs are not included in the analysis framework for VRE generators, but this assumption is offset by the fact that no discount is claimed on future replacements for existing infrastructure, given that the new generation is expected to be like-for-like technology. For instance when wind turbines reach their end of life, they will likely be replaced with the latest wind turbine technology, but can make use of the existing connection equipment.
On Regulatory framework: **Shell** noted that cost considerations should be based on costs consumers pay over time and not headline costs. **PIAC and Shell** raised concerns with the overall regulatory framework which doesn't provide adequate protection for consumers from high costs. For instance when AER undertakes an ex-post expenditure review, this can allow TNSPs to defer/cancel projects and overspend in subsequent regulatory periods leaving consumers with high costs. **PIAC** recommends changes to the ISP Rules and RIT-T to reduce cost impacts.	In response to feedback on modelling the cost to consumers, AEMO notes that the ISP modelling has to be undertaken in accordance with the Cost Benefit Analysis Guidelines[60] from the AER, which require consideration of all capital and operating costs including fuel over the modelling horizon. AEMO acknowledges concerns regarding the regulation of transmission projects. AEMO notes that several processes exist to protect consumers against high transmission costs after completion of the ISP, including decision rules, the RIT-T, the ISP feedback loop, the AER's approval of contingent project applications and the AER's ex-post capital expenditure review. AEMO considers the approval (via contingent project applications) or exclusion (via ex-post reviews) of TNSP capital expenditure for actionable ISP projects to be within the AER's remit and outside the scope of the ISP. Stakeholders are encouraged to engage with consultation processes run by the ESB and AEMC on the regulatory framework.
On transparency: **ENA, Origin, Shell, PIAC and ENA** supported the development of the Transmission Cost Database to increase transparency for stakeholders. **ENA** stated that there may be commercial sensitivities with the Transmission Cost Database being too transparent. It was noted that significant information was being provided and has the potential to be market forming.	AEMO welcomes stakeholder support for the development of the Transmission Cost Database and the increase in transparency that it brings to transmission cost estimation. The framework for the ISP is based on regulatory obligations for disclosure of information and transparency in designing a whole-of-system plan. In accordance with the NER and the ISP rules, AEMO publishes the Transmission Cost Database as a set of inputs that are used in the ISP. Given a historical lack of transparency in this area, AEMO now considers this information to be necessary in demonstrating to consumers that transmission projects are estimated appropriately. AEMO has consulted with the AER and the ISP Consumer Panel on the development of the Transmission Cost Database.
On Reviewing TNSP cost estimates: **PIAC and Origin** supported AEMO's role in assessing TNSP estimates and requests that AEMO should clearly explain any adjustments made.	AEMO acknowledges PIAC and Origin's support on assessment of TNSP estimates. It is important to note that while AEMO may offset TNSP estimates, this process is iterative and may result in TNSPs revising offsets after receiving initial feedback from AEMO. An explanation of the outcomes of this process has been included in the report.

[60] AER. *Cost Benefit Analysis Guidelines*, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable.

Feedback received	AEMO response
On stakeholder engagement and consumer impact: **Shell** stated that AEMO should have consulted on augmentation options in a separate report to allow due process for stakeholder feedback. **ENA** highlighted the importance of continued stakeholder engagement on the projects and alternative options. **ResistHumelink** noted that AEMO had a responsibility to ensure investments were not under-utilised or stranded, leaving consumers with high costs. They also suggested that compulsory acquisition is an oppressive power and a serious failure of Government and the NEM.	AEMO agrees with Shell's suggestion that AEMO should have consulted on augmentation options in a separate report, but notes that this was in fact completed in the Draft IASR (as discussed in the introduction to both the draft and final *2021 Transmission Cost Report*). In response to ENA's feedback on the importance of continued stakeholder engagement, AEMO acknowledges that there is a significant volume of information in the *2021 Transmission Cost Report*. The report is part of the broader IASR, which requires definition of all aspects of transmission for input to the ISP model, including cost, capacity and timing of each project, hence these aspects have been grouped together in one report. AEMO agrees that continued stakeholder engagement on projects and alternative options is extremely important. There will be further opportunity for stakeholder engagement on projects and options in the Draft ISP consultation and through the RIT-T, and subsequent processes. The ISP modelling minimises the risk of stranded investments by including all commercially available technologies, forecasting demand and supply in considerable detail across the regions for the modelling horizon, and staging projects when there is value in doing so. AEMO acknowledges the views on the use of compulsory land acquisition. In its recent guidance note on regulation of actionable ISP projects[61], the AER noted the need for TNSPs to engage with a range of stakeholders, including local communities, prior to submission of the Contingent Project Application (CPA).
On Transmission Cost Database modifications: **Origin, PIAC and ENA** recommended continuous review of the database to assess the under-estimation of costs and adjust inputs as needed. Recent cost information from TNSP projects should be used as well as real cost escalators such as recent data sets, labour and materials markets and state infrastructure projects. **PIAC** raised concerns about systematic underestimating of transmission costs and lack of recent transmission projects in Australia to benchmark against. It suggested use of international data. To increase transparency, **Shell** submitted that AEMO publish the 16 network elements used, the specific network elements included for the projects and the output cost compared with the input cost.	AEMO acknowledges that large transmission projects have historically been under-estimated by both AEMO and TNSPs. This was the catalyst for AEMO's decision to commission the Transmission Cost Database, along with the objective of increasing transparency. A large amount of new data has been published through the database and the cost estimate outputs. Data used for benchmarking was provided by TNSPs on a confidential basis and is therefore not able to be published. Due to lack of recent projects in Australia, the inaugural Transmission Cost Database was benchmarked on the most recent information available on transmission projects. International data may be used in future updates where suitable local data is not available, as long as it can be suitably adjusted to local conditions. AEMO intends to update the Transmission Cost Database at least every two years in line with the ISP schedule. This process will use the latest data available on recent completed projects and unit price estimates. While AEMO agrees that the cost of transmission will change with labour and material costs, these factors are highly uncertain due to a range of factors (including competing domestic and

[61] AER, Guidance note on Regulation of actionable ISP projects, March 2021, at https://www.aer.gov.au/system/files/AER%20-%20Final%20Guidance%20note%20-%20Regulation%20of%20actionable%20ISP%20projects%20-%20March%202021%20-%20FINAL%20FOR%20PUBLICATION%2812129318.1%29.pdf.

Feedback received	AEMO response
	international infrastructure projects in other sectors). Rather than projecting these highly uncertain variations, AEMO will leverage take-one-out-at-a-time (TOOT) analysis to inform the sensitivity of actionable projects to increases in capital costs to provide guidance on potential cost ceilings beyond which projects may not be viable.
On stating the identified need for network options: **Shell, MEU and ENA** proposed that the identified need should be included for transmission options. This allows non-network solutions to be considered. **Shell** highlighted that it is important that the ISP clearly state an identified need because it replaces the PSCR for actionable ISP projects. It was also suggested by **MEU** that system strength needs should be included to allow non-network options to be more effectively considered.	AEMO confirms that any ISP project declared as actionable will have an identified need described in the ISP, and non-network options for this need will be considered. AEMO consulted on and finalised a methodology to describe how it will define the identified need for ISP projects in the ISP Methodology[62]. While the ISP does replace the PSCR for actionable ISP projects, these projects do not become actionable until the ISP is finalised. For this reason, AEMO considers that the identified need can only be finalised at the final ISP stage, with a draft recommendation on identified needs provided in the draft ISP, rather than in the IASR. AEMO consulted on non-network options for the 2022 ISP in the IASR. Additionally, AEMO will call for submissions for non-network solutions in relation to actionable projects identified in the Draft ISP or the final ISP[63]. Regarding system strength, AEMO notes that while system strength solutions are costed and included in the ISP, the ISP does not lock in a preferred option. AEMO acknowledges the system strength frameworks and welcomes non-network proponents to participate in non-network consultations for actionable ISP projects.

5.4.2 Feedback received on the flow path augmentation and renewable energy zone development options

AEMO questions:

- Has AEMO considered the most appropriate flow path augmentation options? If not, what else should AEMO consider?
- Has AEMO considered the most appropriate options for expanding transmission access in REZs? If not, what else should AEMO consider?
- What, if any, additional factors should AEMO consider when identifying network augmentation options?

[62] AEMO. *ISP Methodology*, at https://aemo.com.au/en/consultations/current-and-closed-consultations/isp-methodology.

[63] AEMO will consult on non-network options for all actionable projects in the Draft ISP or final ISP in accordance with 5.22.12 and 5.22.14(c)(1) of the NER.

Feedback received	AEMO response
On Flow paths and REZs: **Shell and MEU** questioned why there was a delineation of REZ and flow path augmentations in the report. They should not be considered separately as there is significant cross over between the two, for example VNI West.	AEMO acknowledges that the delineation of REZ and flow path augmentation in many cases is presentational. However AEMO notes that they are not treated separately when modelled, nor are they modelled in significantly different ways.
On Augmentation Options: **Shell** stated that AEMO's focus is on large network options not targeted options that might provide additional capacity at lower costs. **Shell** expanded on a series of Victorian upgrades that might defer the need for VNI West. **Shell** also noted that transfer capacity from Central to Northern NSW and to Southern Queensland could be improved by developing a 25 km long 330 kV transmission line between Bayswater and Muswellbrook. **Resist HumeLink** proposed reviewing SNSW to CNSW options for environmental costs and an assessment of underground options.	In 2020 ISP, alternative options to VNI West were modelled and tested. The 2020 ISP recommended a large interconnector between Victoria and New South Wales as an actionable project, with two alternative routes identified. A RIT-T is in progress for to evaluate the economics of different options for VNI West. For 2022 ISP modelling, each of these options and additional alternative options beyond the 2020 ISP actionable VNI West option will be considered. AEMO considers that the spread of options for increasing the capacity between Victoria and New South Wales is appropriate, and that sequencing of upgrades can be considered in more detail in subsequent RIT-Ts. Options to increase transfer capability from Southern QLD to Northern NSW and Central NSW include additional 330 kV and 500 kV network and non-network options. AEMO considers that minor upgrades such as the 25 km line proposed by Shell can be more easily evaluated by the local TNSP outside the actionable ISP framework. If an actionable ISP project is triggered or increase the transfer capacity on this flow path, that RIT-T could include a wider range of upgrades, including staging. The incorporation of environmental costs and underground options is discussed in Section 5.4.1 above.
On Projects and Non-Network Options: **Shell** noted that many network and non-network options have not been costed by TNSPs or interested parties. The **MEU** noted that discussion on findings from the 2020 ISP may be premature as the 2022 ISP is still being developed and stakeholders may have concerns on whether they need to respond to each individual augmentation. **ENA** requested further information on virtual transmission costs, the cost of infrastructure (battery and demand response), and how this is determined and reviewed by TNSPs. **Shell** also proposed greater consideration of non-network options. Using full BESS cost is worst possible edge case. Flexibility and optionality should be valued and instead AEMO should apply a percentage discount to NNOs sourced from TNSPs.	AEMO acknowledges that the *Draft 2021 Transmission Cost Report* included placeholders for a range of non-network options. AEMO has called for feedback on non-network options in both the Draft IASR and the *Draft 2021 Transmission Cost Report.* AEMO also acknowledges that some projects that are estimated by TNSPs were not included in the *Draft 2021 Transmission Cost Report*. AEMO stated the most recent available estimates for these projects, but noted that some updates from TNSPs were expected by 30 June 2021. AEMO has reviewed the *Transmission Cost Report* in response to MEU's commentary about the *Draft 2021 Transmission Cost Report* referring to 2020 ISP. AEMO considers that these select references provide context as to why AEMO initiated the transmission cost review, why AEMO triggered preparatory activities for TNSPs to develop individual cost estimates, and which projects are currently actionable. The Draft 2021 IASR and the *Draft 2021 Transmission Cost Report* invited proponents to provide cost data on some non-network options (e.g. virtual transmission lines) rather than estimating a cost. While AEMO can estimate the cost of virtual transmission lines using GenInfo costs, these projects are only included if they are competitive with the respective transmission options. AEMO appreciates that non-

Feedback received	AEMO response
	network options may have multiple revenue streams that are not valued in the ISP, and will consult on non-network options for any actionable ISP project. AEMO notes that significant joint planning is undertaken with TNSPs through the ISP process which includes reviews of cost estimates and design options. Additionally, any costs received by AEMO through the call for non-network submissions are passed on to the relevant TNSP for inclusion in the RIT-T process (subject to confidentiality considerations). Regarding Shell's suggestions to not use the full cost of non-network options, and to value their flexibility and optionality, AEMO notes that the AER published a final decision on "Guidelines to make the ISP actionable"[64] which clarifies this matter. On page 26, the AER presents an example: "*if a credible option required a grid-scale battery that cost $700,000, the net benefit would be reduced by this amount, regardless of whether a TNSP or market participant purchased the battery*".
Benefits of options **Shell** noted that the degree to which option increases network capacity or provided reliability benefits has not been quantified. The methodology could be improved by including benefits such as reliability or increased network capacity.	The increased network capacity attributable to each augmentation option is listed in the tables in each section of the *2021 Transmission Cost Report*, under the Augmentation Options heading. Reliability benefits are an outcome of the ISP modelling, and are not known at the IASR stage (i.e. they are an outcome of ISP modelling rather than an input).
Renewable Energy Zones **Moyne Shire** stated the council does not support any investment in new transmission in the Moyne section of the South West REZ until recommendations from National Wind Farm Commission (2017) have been implemented. **Moyne Shire** noted that REZ development is usually in rural communities for the benefits of city consumers and it proposed a government-led package for host communities to balance the inequities signalled in the ISP.	AEMO acknowledges that there is a need for coordination of VRE development within REZs, and has met with Moyne Shire to discuss their concerns, and provided suggested avenues for further engagement in regulatory framework. Prior to approval and construction of any transmission options, significant further community consultation will occur as part of subsequent regulatory investment tests carried out by TNSPs.

5.4.3 Feedback received on generator connection costs

AEMO questions:

- Has AEMO considered all the relevant factors in estimating costs of connection of generator projects? If not, what else should AEMO consider?

[64] See https://www.aer.gov.au/system/files/AER - Regulatory investment test for transmission application guidelines - 25 August 2020.pdf.

Feedback received	AEMO response
Connection Costs **Shell** suggested connection costs for solar and wind technologies used cost per km figure rather than assuming new generators are located 5-10 km from existing networks. This should also be considered for the number of assumed feeders. Different connection costs have been assumed for non-renewables and renewables. **Shell** recommended that connection costs should be independent of the generation technology, including battery connections.	For the new generation planting outcomes in the ISP, detailed location specific of projects is not known at this stage of study. AEMO notes that specific connection distances apply to each REZ, and even using a $/km value, a distance must be assumed or calculated. Additionally, connection costs have a relatively small impact on overall system costs. Therefore AEMO proposes to retain its existing approach to connection costs.
Other Considerations **Shell** queried the transfer capability used for the generator connections at nominated voltages and assumed feeder numbers. **Shell** proposed that AEMO should consider use of inverter technology to provide network support services, as an alternative to synchronous condensers.	The capability of the generator connections shown is based on typical generation project sizes for the specific connection voltages shown as opposed to the maximum capacity of a connection transmission asset. i.e. the network costs covered in the connection costs is specific to a new generation project, as opposed to a shared network asset. This is different to a REZ expansion option, where the full capacity of the network is assumed able to be utilised. Connection costs have been further reviewed in the final IASR to ensure a variety of different voltage levels and conductor sizes are considered in order to minimise the calculated connection costs. Regarding system strength, AEMO notes that while system strength solutions are costed and included in the ISP, the ISP does not lock in a preferred option. The use of synchronous condensers represents an existing solution. AEMO acknowledges that there are alternatives to synchronous condensers which should be considered as a REZ is developed.