Report: Transmission planning and investment for clean electricity

CLIENT: Clean Energy Investor Group

DATE: 09 June 2022

Version history

Version	Date	Description	Prepared by	Approved by
1.0	17/03/22	First Draft	Jacqui Fenwick Minh Nguyen Alan Rai	Alan Rai
2.0	05/04/22	Second Draft	Jacqui Fenwick Nick Porter Alan Rai	Alan Rai
3.0	23/05/22	Final	Nick Porter Alan Rai	Alan Rai
4.0	09/06/22	Final for release	Alan Rai	Alan Rai

Contact

Jacqui Fenwick (jacqui.fenwick@baringa.com 0478 177 630)

Alan Rai (alan.rai@baringa.com 0433 428 620)

The Baringa Partners offices in Australia are in Sydney, on the land of the Gadigal people of the Eora Nation, and in Melbourne, on the land of the Eastern Kulin Nation. We acknowledge the traditional custodians of this land - past, present and future - and respect their continuing culture and the contribution they make to the life of these cities and regions.

Copyright

Confidentiality and limitation statement

Contents

Figures

Tables

Executive Summary

Federal and State governments in Australia have committed to achieving economy-wide Net Zero CO_2-e emissions (dubbed 'Net Zero') by 2050, with all sectors needing to make a contribution. For the electricity sector, most of its emissions reductions needs to occur in the 2020s and 2030s to support the economy reaching Net Zero by 2050. Zero-emissions electricity is also needed to support electrification-driven decarbonisation in sectors ranging from transport to steelmaking. This transition to zero-emissions electricity, requires rapid development of new generation, storage and other supporting technologies to replace exiting fossil fuel-powered generators.

A rapid energy transition hinges on timely and efficient transmission network expansion. It is critical that the national regulatory framework for transmission development and investment is fit-for-purpose to facilitate the build out of clean energy where and when it is needed to replace retiring thermal plant and meet the demand growth from electrification.

A commendable program of recent reforms, along with Net Zero now embedded in all scenarios of the Draft 2022 ISP, mean the national framework does now appear capable of delivering the network infrastructure needed for economy-wide Net Zero by 2050. At an electricity-sector level, the ISP appears aligned with achieving a relatively low-emissions grid (<20Mt CO_2-e) by 2035 and closer to zero emissions (<10Mt CO_2-e) by 2040. The extent to which is considered to be sector-wide Net Zero is dependent on assumed use of offsets. This trajectory accommodates increasing demand across the NEM as decarbonisation efforts result in electrification.

However, the truncated timeframes enabled by the recent reforms have yet to be demonstrated, and a number of related processes risk introducing additional delays. These related processes include the risk of incumbent TNSPs delaying development of major projects due to financeability concerns and a lack of obligation on TNSPs to build the network. More critical to potential time delays are processes such as gaining social licence (or, worse, not gaining social licence) and jurisdictional approvals processes.

To safeguard the timely development of the necessary transmission infrastructure, and the trajectory to Net Zero, reforms should be pursued to address these ancillary risks to development as well as to further reduce timeframes for the streamlined Regulatory Investment Test for Transmission (RIT-T) and broader economic regulatory framework.

While major reforms are worth considering for the longer-term suitability and sustainability of the framework, for the most part *incremental* reforms are needed to deliver the near-term transmission infrastructure in the NEM in a timely manner, given pressing decarbonisation goals. The regulatory framework for transmission planning in the NEM – of which we focus on system planning and economic regulation – requires, in our view, evolution rather than revolution to increase timeliness and enable NEM decarbonisation in order to contribute to economy-wide Net Zero by 2050.

Delaying transmission increases costs for Australia, in terms of not realising the benefits that more transmission capacity enables:

- lower wholesale and retail electricity prices
- more broadly, the health and economic benefits from decarbonising Australia's energy consumption through renewables-powered electrification, and
- the additional economic benefit from exporting clean energy to the rest of the world in the form of green hydrogen and green ammonia.

We have considered the impacts from delaying the scale of intra- and inter-regional transmission network augmentations required to achieve economy-wide Net Zero by 2050 by three years. This time period represents a reasonable estimate of the impact of not implementing our policy recommendations (discussed later in the Executive Summary).

Averaging across all NEM regions, a three-year delay to transmission augmentations would leave each residential electricity customer $20 p.a. worse off, and each small-to-medium enterprise (SME) customer $70 p.a. worse off (in 2021$). Victorian residential customers are the worst-off (by $25 p.a., or $813 over the FY2022-FY2055 period, per customer), while NSW residential customers are least impacted ($13 p.a., or $417 over FY22-FY55, per customer). Victorian SMEs are also worst-off (by $128 p.a., or 4,231 over FY22-FY55, per SME), with South Australian SMEs least worse-off (by $51 p.a., or $1,668 over FY22-FY55, per SME). These values are a conservative estimate of costs as it excludes the forgone employment and income benefits from delaying transmission investment.

Moreover, Australia's materiel living standards would be even more negatively impacted – via higher electricity prices, lower jobs, and lower incomes – if transmission was delayed inevitably. Analysis of selected third-party studies shows not achieving Net Zero would mean $2,000-$5,000 less per Australian (a c.10-25% decrease in average incomes per capita) in today's dollars.

Policy positions

The following policy positions are recommended for further consideration. As with all prospective policy reforms, these positions merit detailed consideration, analysis and consultation prior to a decision being made on their adoption.

Network Planning

- **Net Zero and a decarbonisation trajectory aligned with a <2°C warming future should be embedded into the ISP through government commitments**. This is because setting these targets and emissions trajectories requires whole-of-economy analysis, which the energy market bodies are not best-placed to undertake.
- **The ISP should remain a biennial publication.** The administrative burden entailed in revising the frequency appears disproportionate to the need for change, at this stage. The biennial publication appears to balance minimising inter-ISP 'deltas' with stability needed to progress RIT-T projects with minimal remodelling delays.
- **Consistent adoption of ISP scenarios and outputs should be implemented with a Ministerial Statement in the near-term, and introduction of a decarbonisation objective into the National Electricity Objective when feasible**. This includes AEMO using the same warming-differentiated scenarios for its Electricity Statement of Opportunities (ESOO) and Gas Statement of Opportunities (GSOO), noting this was done in AEMO's 2022 GSOO.

Relatedly, we recommend an **update to the AEMC's Applying the *Energy Market Objectives* paper**. Last published in July 2019, this paper discussed how climate change considerations impact the AEMC's rule-making process and how decarbonisation policies and targets impact its assessment of the National Electricity Objective and related Objectives.

- **Identification and assessment of non-network solutions should continue to occur under existing arrangements.** The approach introduced in the 'actionable ISP' reforms appears to effectively balance consideration of non-network solutions with a streamlined and less-duplicative framework.

Assessment and costing of credible options

- **The option to remove the requirement for a benefits assessment in the RIT-T is worth considering, for actionable ISP projects.** This approach may reduce duplication between the ISP and RIT-T. TNSPs should still be entitled to undertake an independent benefit assessment, including assessing additional benefits categories, but the benefits could otherwise be assumed equal to those identified by AEMO in its ISP modelling.
- **To improve the quality of cost assessments in the RIT-T, the existing opportunity to undertake staged CPAs should be revised to a requirement for large projects.** This would ensure early works inform final CPAs which are subject to a feedback loop assessment, safeguarding cost-efficient outcomes for consumers. **Existing provisions which allow AEMO to direct that REZ Design Plans are developed and that preparatory activities are undertaken for future ISP projects could be revised to require AEMO to do this, to ensure preparatory activities are completed earlier for all future projects in the ISP. Finally, a review of the recent reforms to the treatment of early works and preparatory activities could be mandated, to assess whether these reforms have delivered intended outcomes.**
- **The feedback loop mechanism should be amended to introduce a proactive assessment of maximum project costs which would still sit in the Optimal Development Path.** This would reduce the risk of time delays introduced through the reactive feedback loop approach. In combination with the preceding two dot points, these positions represent appropriate **modifications to the set of 'decision rules' under the ISP**.
- To provide more certainty that the proposed timeframes of the national framework will actually be achieved**, an oversight role should be introduced to monitor and report on timeliness of the process, identifying opportunities for improvement.**

Accommodating social licence initiatives and broader jurisdictional needs

- **AEMO should be required to include a social licence sensitivity in its ISP modelling,** which quantifies the potential cost impacts of building and maintaining the social licence to operate.
- **The option to integrate jurisdictional-identified needs into ISPs alongside AEMO's technical identified needs should be considered**. This would mean actionable ISP project requirements could be defined with a broader view to what jurisdictions expect the project to deliver, including for example environmental, social and employment outcomes, providing an opportunity to align with planning needs earlier in the process.

Responsibility for projects

- **A decision on whether to introduce contestability into network ownership and operation is introduced as a longer-term reform option should be informed through more detailed cost and benefit analysis**. It appears to offer potential benefits for developing interconnector projects however the benefits of contestability for other projects is less clear**. If introduced, a national contestable process should seek to align with the existing jurisdictional processes** in Victoria and NSW where possible to make future harmonisation more straight-forward. For non-contestable network ownership and/or operation, we consider the existing schemes – such as the Efficiency Benefit Sharing Scheme and Capital Expenditure Sharing Scheme – provides sufficient incentive for TNSPs to consider contestable providers of network services (i.e., even if TNSPs own the network infrastructure, they may not necessarily build it themselves).
- **Government contributions to the cost of network infrastructure should be retained as an option under the national framework as a means to progress projects which are earlier or of a different nature than those projects identified as optimal in the ISP** (particularly when governments are seeking to meet their jurisdictional commitments). This role would be additional to the *liquidity* Governments can provide; namely, providing funding to progress network projects though the costs of these projects, including Government financing costs are, ultimately, recovered from consumers.

In summary, our policy positions and recommendations represent appropriate modifications to the existing regulatory framework for transmission planning and investment, which balances the following at times competing considerations:

- providing greater certainty for investors in relation to the location and timing of transmission network augmentations: investors in generation, storage and, increasingly, transmission network infrastructure
- maximising net benefits for consumers who, ultimately, pay for most, if not all, of transmission network infrastructure identified as optimal under the ISP, and
- reducing duplication between the various regulatory processes, and
- increasing timeliness of project delivery by shortening the timeframes between system planning, project design and then delivery.

1 Introduction

1.1 Networks are crucial to Australia achieving Net Zero

Australian Federal and State governments have committed to achieving economy-wide Net Zero by 2050, reflecting global agreements to limit global warming to below 2°C.[1] Achieving this goal requires first determining an economy-wide CO_2-e emissions reduction target and then determining each sector's contribution to that target. For the electricity sector, most of its emissions reductions needs to occur in the 2020s and 2030s to support the economy reaching Net Zero by 2050. This will be achieved by increased penetration of zero-emissions electricity (chiefly, renewables), storage and other complementary low-carbon technologies, to decarbonise the power system and also support electrification-driven decarbonisation in sectors such as transport, steelmaking, and manufacturing.

- Significant additional clean generation and storage capacity will be needed this decade, and then increasingly so in future decades, to replace retiring fossil-fuel generators. In Australia's National Electricity Market (NEM), the retirement dates of coal generators are being progressively brought forward, with the risk generally tilted towards earlier rather than later coal closure. Already in 2022, three prominent coal generators have brought forward their closure dates.[2]

- Significant additional capacity will also be needed to meet growing demand from the zero-emissions electrification of transport, residential heating and cooking, manufacturing, and heavy industry, including green hydrogen, in a reliable and secure way. Enabling zero-emissions electrification and attendant growth in electricity demand is critical to facilitating a whole-of-economy Net Zero future.

AEMO's *Draft 2022 Integrated System Plan (ISP)* identified that more than 125 GW of new variable renewable energy capacity would be needed by 2050, in addition to existing and committed capacity, to both replace retiring generation and meet the growth in electricity demand under AEMO's most likely *Step Change* scenario.[3] This need for much greater renewable energy capacity reflected the carbon constraints which defines *Step Change*: a carbon budget for the NEM based on limiting global warming to 1.8°C. To meet this decarbonisation objective, the Draft 2022 ISP identified the major system needs, and the timeframes in which these needs should be acted on, to enable this new capacity.

The development of substantial new transmission network infrastructure will be crucial to unlocking this additional generation and storage capacity and in turn contributing to decarbonising Australia's power sector and economy more broadly whilst maintaining reliability and security. However, the existing transmission network in the NEM is insufficient to accommodate the amount of new generation and storage capacity needed to replace retiring generation, and well short of that needed

[1] For 'dangerous' global warming not to occur, it is generally considered that the global temperature rise would need to be no more than 2°C by the year-2100, relative to year-1900.

[2] The 2022 announcements are: Bayswater Power Station, Loy Yang A Power Station, and Eraring Power Station. This is additional to the two announcements of earlier closures in 2021: Yallourn Power Station and Mt Piper Power Station.

[3] AEMO, Draft 2022 Integrated System Plan, p38-39: 38 GW of new variable renewable energy (VRE) in NSW, 47 GW of new VRE in QLD, 23 GW of new VRE in VIC, 15 GW of new VRE in SA, and 2.5 GW of new VRE in TAS.

to support economy-wide electrification. In order to achieve the required decarbonisation of the NEM and Australia overall, it is critical the transmission network regulatory framework and related processes (such as consultation and planning approvals) can deliver the required size and location of network and/or non-network solutions in an efficient, effective, and timely manner consistent with the timing in AEMO's ISP.

Recent 'actionable ISP' reforms have aimed to streamline the NEM's regulatory framework as well as making it more suitable for delivering the large, anticipatory, infrastructure identified in the ISP. There nonetheless remain concerns about whether the national framework will be capable of delivering the needs of a Net Zero future. These ongoing concerns have driven recent rule change proposals and the initiation of the Transmission Planning and Investment Review by the Australian Energy Market Commission (AEMC).

1.2 Investor Principles

The Clean Energy Investor Group (CEIG) represents, and advocates for, clean energy investors. Its members are active investors in clean energy in the NEM, with a significant portfolio of existing assets. The CEIG's vision is for a strong, investable, market where competitive institutional investment plays a central role in delivering the significant low-cost capital needed for the energy transition.

The CEIG has raised concerns that the policy and regulatory environment in the NEM places excessive risk on investors, increasing the cost of capital as a result, which ultimately leads to higher costs for consumers.

In 2021, the CEIG published five Investor Principles[4], to align the development of the NEM with global markets and make the NEM a more internationally competitive market for clean energy infrastructure investment (Figure 1). The Investor Principles are designed to collectively deliver the energy transition with lower cost outcomes for electricity consumers and taxpayers.

We note one important aspect of Investor Principle One (IP1) has been achieved with the release of AEMO's Draft 2022 ISP: *Step Change* is now considered by AEMO, and many other stakeholders, to be the most likely of the various alternative ISP scenarios.

1.3 Purpose and scope

The CEIG engaged Baringa Partners to help it develop a position on the future of transmission planning and investment in the NEM. The CEIG sought advice on whether the current framework is capable of delivering new network investment for our Net Zero future and, if not, what changes should be made to rectify this. Baringa was also asked to consider the cost to the market of delayed network development, if this arises.

Baringa has undertaken a qualitative analysis of the transmission network regulatory framework as relevant to network planning and investment, to form a view on whether change is required, and

[4] Clean Energy Investor Group, 2021, Clean Energy Investor Principles: Unlocking low-cost capital for clean energy investment, https://ceig.org.au/wp-content/uploads/2021/08/CEIG_Clean-Energy-Investor-Principles.pdf

what this could look like. We have also undertaken high-level quantitative analysis to demonstrate the nature of market outcomes if network development is delayed.

Separate to this program of work, the CEIG has also developed a position on transmission access and pricing reform. Baringa's engagement does not include transmission access and pricing but is intended to be complementary to this work.

Figure 1: The Clean Energy Investor Group's *Investor Principles*[5]

State-specific approaches to some elements of transmission planning and investment have been developed, however this study is focused on the national framework.

[5] Clean Energy Investor Group, 2021, Clean Energy Investor Principles: Unlocking low-cost capital for clean energy investment, https://ceig.org.au/wp-content/uploads/2021/08/CEIG_Clean-Energy-Investor-Principles.pdf

2 Current transmission planning and investment framework

2.1 How the current framework works

The national framework for transmission planning and investment now includes two processes for delivering major transmission projects – one for actionable ISP projects, and one for other projects. The 'other' projects include those identified in the ISP as future projects (rather than near-term actionable projects) and other projects identified by Transmission Network Service Providers (TNSPs) or AEMO (in Victoria). Given the level of consultation undertaken by AEMO in its development of each ISP, most major transmission projects required to deliver future system needs in the NEM would be expected to appear in the ISP, however views on timing of the need may vary.

The processes for planning of and investment in actionable ISP projects and other projects have been detailed in a number of recent publications, including the AEMC's transmission planning and investment review consultation paper. This Section provides a high-level summary, for context.

2.1.1 Actionable ISP projects

Over the last few years, the Energy Security Board and market bodies have led a program of work to make the ISP 'actionable' and, particularly, to enable the fast-tracking of projects identified for near-term development in the latest ISP.

When a final ISP is published, major projects required in the near-term will be identified as actionable projects. This triggers a requirement on the relevant jurisdictional TNSPs to commence the Regulatory Impact Test for Transmission (RIT-T) for these projects (if they haven't already). AEMO can also use the ISP to require jurisdictional planning bodies to develop REZ design reports[6].

Key elements in the framework for actionable ISP projects are:

- AEMO publishes a draft ISP, identifying draft actionable projects (identified needs, and candidate project options to address these needs)
- AEMO consults on the draft, including requesting proposals for non-network solutions to meet the draft identified needs
- AEMO publishes a final ISP, identifying the final actionable projects (identified needs, and candidate project options to address these needs)
- TNSP required to commence preparatory activities for actionable projects 'as soon as practicable'

[6] REZ Design Reports are intended to be interim publications that sit between the high-level ISP REZ proposal and the substantiative investment proposal for specific REZ infrastructure when a project is being developed. The Reports should provide the outputs of preparatory activities, including engineering design and costing work, and should include a community impact assessment, among other things.

- TNSP required to publish a Project Assessment Draft Report (PADR), canvasing potential network solutions (and potential non-network solutions, if viable options have been proposed through the draft ISP consultation) and undertaking a cost-benefit analysis of each viable option
- TNSP publishes a Project Assessment Conclusions Report (PACR) with the preferred solution
- TNSP develops a contingent project application with the preferred solution
- AEMO undertakes a ‘feedback loop’ assessment of the preferred solution
- TNSP submits the contingent project application to the AER for its assessment and approval
- TNSP commences detailed design work on the approved option, and progresses to development and commissioning
- TNSP starts recovering costs when the solution is forecast to be commissioned/operational

The AER’s contingent project framework allows for some projects to progress through the approvals process in stages, such that funding for early works of a project could be approved for recovery ahead of the broader project. This enables more detailed information to be gathered ahead of an investment decision on progressing the full project implementation. It is also intended to enable more detailed project planning to occur upfront to better manage costs later, as it ensures the TNSP will have revenue certainty to commence the early works which can be significant in costs, particularly for large and complex projects.

2.1.2 Other major regulated projects

For regulated projects which are not identified as actionable projects in the most recent ISP, the transmission planning and investment framework that existed prior to the ISP remains. This applies to both projects which do not appear in the ISP, and those that do appear in the ISP but are not actionable projects (such as future projects).

The framework for actionable ISP projects enables a more streamlined RIT-T process, given the work that’s already occurred through the ISP. Whereas other projects are subject to the ‘full’ RIT-T process. Key elements of this framework are:

- TNSP identifies a need in its network.
- TNSP publishes a Project Specification Consultation Report (PSCR), thereby commencing a RIT-T
- TNSP publishes a PADR, canvasing a number of potential network and non-network solutions
- TNSP publishes a PACR with the preferred solution
- TNSP submits a cost forecast to the AER for assessment and approval of associated revenue – occurs either through the five-yearly revenue determination or via a contingent project application (CPA)[7]

[7] If the need and preferred option is able to be forecast with sufficient certainty at the time of the TNSP’s five-yearly transmission determination, then the TNSP includes the project in its revenue proposal for the AER’s assessment and

- TNSP commences detailed design work on the approved/preferred option, and progresses to development and commissioning
- TNSP starts recovering costs when the solution is forecast to be commissioned/operational

As for some actionable ISP projects, other projects are also able to be progressed in stages if proposed by the sponsoring TNSP.

There are a number of other mechanisms in the regulatory framework for delivering network (or non-network) solutions which are not funded with regulated revenue and are not providing prescribed services. These include the rules for Dedicated Connection Assets, Designated Network Assets, Identified User Shared Assets, and market network services (unregulated interconnectors). The processes for assessing and approving these assets are very different from the processes for regulated assets, described above, primarily because the rigorous consumer protections are not needed to the same extent for network assets or services which are not solely consumer-funded.

Through its separate program of work on transmission access and pricing, the CEIG has proposed introducing a new network development and financing measure to sit alongside access reforms. The proposed measure would enable generation projects to fund augmentations to the local shared transmission network to accommodate their connection into capacity-limited areas of the existing network, along with the payment of 'deep' transmission-connection charges. The transmission charge model is not currently well-accommodated in the national regulations, but would be expected to require a new, fit-for-purpose regulatory framework.

2.2 Strengths of the current framework

The following is not intended to be a comprehensive list of positive attributes of the existing framework, of which there are many. Instead, it identifies a few key strengths at a high level:

- Independent, NEM-wide, system planning
- Planning for Net Zero
- Improved timeframes for actionable ISP projects

2.2.1 Independent, NEM-wide, system planning

The introduction of NEM-wide system planning, published in AEMO's biennial ISP, has enabled a central view of the whole-of-system needs across the interconnected NEM. It allows for temporally- and geographically-efficient coordination of generation and transmission investment to unlock the least-cost means of meeting anticipated demand over time. This national planning approach is expected to deliver more efficient outcomes than could be achieved under a region-by-region and/or time period-by-period 'snapshot' approach.

approval. If the project need or solution is not able to be forecast with sufficient certainty, the TNSP may propose it as a contingent project in its revenue proposal. A contingent project 'trigger' is also specified in the revenue determination. After the trigger occurs (e.g., successful completion of a RIT-T), the TNSP submits a contingent project application to the AER to reopen the capex/opex forecasts in the revenue determination to include the project.

Importantly, the NEM-wide planning is undertaken by AEMO as an independent system planner, rather than by an individual network service provider with revenue tied to network development. In developing the ISP, AEMO considers multiple scenarios and sensitivities, which also helps to deliver an independent and robust view of future investment and development needs.

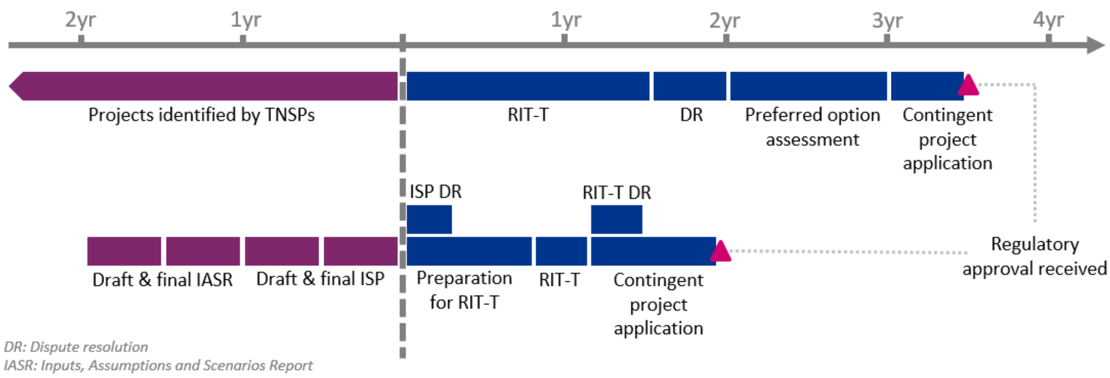
2.2.2 Planning for Net Zero

In the Draft 2022 ISP, all four scenarios considered by AEMO are in line with achieving Net Zero emissions by 2050, nationally.[8] The shift to planning for a network which delivers the Net Zero trajectory is a strength of the national framework. By using Net Zero-aligned scenarios in national planning, the near-term projects required to deliver this emissions trajectory will be subject to the more streamlined regulatory framework and more likely to be delivered in a timely manner.

2.2.3 Improved timeframes for actionable ISP projects

The regulatory framework for actionable ISP projects has been streamlined and truncated through the actionable ISP reforms. In particular, the ISP now identifies the project need, and the RIT-T therefore no longer includes the first report, the PSCR, and associated consultation period on the PSCR, in which the TNSP demonstrated the need for the project. Further, the AER's detailed preferred option assessment in the RIT-T has been removed, and more clarity provided on modelling assumptions and scenarios for TNSPs. This allows for a significant time saving, as shown in Figure 2.

Figure 2: Relative timeframes of the traditional economic regulatory framework for transmission, and that of the actionable ISP amendments, based on ESB documentation[9].



2.3 Outstanding challenges and concerns

The following is not intended to be a comprehensive list of challenges of the existing framework, but identifies a few key challenges that are relevant to the question of whether the existing transmission regulatory framework reform can deliver the requisite transmission capacity in the requisite timeframes:

---

[8] The variation in Draft 2022 ISP scenarios therefore reflects differences in pre-determined CO_2-e budgets i.e., the emissions *trajectory* to Net Zero in 2050.

[9] Timeframes are those published by the ESB: ESB, Actionable ISP Rule Change Fact Sheet, https://web.archive.org.au/awa/20210603141100mp_/https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/ESB%20Actionable%20ISP%20Rule%20Changes%20Fact%20Sheet.pdf

- Timeframes not demonstrated
- Process for non-ISP projects still slow
- Process still duplicative
- Social licence not appropriately accommodated
- Risk of inefficient cost outcomes

2.3.1 Timeframes not demonstrated

While the actionable ISP process has been introduced to streamline the economic regulatory framework and reduce timeframes for the delivery of actionable ISP projects, its efficacy at achieving these outcomes has not yet been demonstrated. Given the recency of the rule changes to implement the actionable ISP framework, we have only seen it applied to projects which were already progressing through the assessment and approvals process (such as Project EnergyConnect). Until it has been applied to actionable ISP projects over the full regulatory lifecycle, it is not clear whether the actionable ISP process is truly capable of achieving the proposed and intended expedited timeframes.

2.3.2 Process for non-ISP projects still slow

For projects which are not actionable ISP projects (non-ISP projects or ISP projects which are not actionable), the economic regulatory framework still entails a lengthy process. The ability to adopt ISP input assumptions, other modelling parameters and scenarios – as contained in AEMO's *Inputs, Assumptions and Scenarios Report* (IASR) – may help to reduce timeframes by removing the scenario definition from the hands of the TNSP, but the process is nonetheless still likely to take a number of years to complete.

2.3.3 Process still duplicative

A range of stakeholders, including AEMO, the ESB and AER, have proposed additional ways to streamline the current economic regulatory framework.[10] While the ISP, RIT-T and CPA all have unique and important purposes, they do entail some duplication. In particular, they require incrementally greater levels of cost assessment for projects. A simplified view of key outcomes achieved by the ISP, RIT-T and CPA is provided in Table 1, illustrating the overlap between these three processes.

Table 1: High-level view of the processes captured in the ISP, RIT-T and CPA stages

Regulatory process	Identify a system need	Identify network options to meet need	Identify non-network options to meet need	Cost-benefit assessment of options	Identify preferred option	Detailed costing of preferred option	Approval
ISP	■	■	■	■			
RIT-T		■	■	■	■	■	
CPA						■	■

Source: Baringa Partners LLP

[10] For example, see AEMO's submission to the AEMC's Transmission Planning and Investment Review consultation paper: https://www.aemc.gov.au/sites/default/files/documents/aemo_8.pdf

We do not propose the existence of the three individual processes is an issue in and of itself. That is, consider some of the duplication in these three processes to be *necessary* given the need to balance timeliness of infrastructure development and delivery with minimising stranding risk to consumers, given the consumer-funded nature of economically-regulated transmission infrastructure. This said, there *is* some unnecessary duplication in the cost assessment of projects (in the cost-benefit assessment and again in the costing of preferred options) which could be reduced. The AEMC acknowledges the potentially duplicative nature of the process as a concern in its Transmission Planning and Investment Review consultation paper:

> "Each component — the ISP, RIT-T and AEMO feedback loop — play an important and distinct role in the economic assessment of actionable ISP projects. However, their interrelated nature raises questions around whether the economic assessment process for actionable ISP projects is appropriately designed. In particular, there may be a degree of duplication or redundancy in the process and, as such, there may be opportunities to streamline the process."[11]

2.3.4 Social licence not appropriately accommodated

The economic regulatory framework for major transmission investments is a critical pathway to the development of projects and has historically been a source of delay. However, it is not the only potential source of delay. As the economic regulatory framework is streamlined, and likewise as the number and scale of major transmission projects increases, other causes of delay are likely to arise and become more pronounced especially if left unaddressed.

In particular, establishing and maintaining the social licence to develop major new infrastructure in regional Australia is likely to become increasingly challenging as the number and scale of projects grows[12]. Concerns about community impacts and land-use are already presenting obstacles for some generation and transmission projects in the NEM – VNI West and Marinus Link are two examples of the latter[13] – and early and genuine community engagement and benefit-sharing are of growing significance in project development.

Social licence issues, if not addressed in an adequate and timely fashion, can increase the costs of transmission and delay its buildout, potentially for several years. The limits to social licence can apply both to the rate of development and to the cumulative scale of development. Constraints of either kind pose a risk to the achievement of electricity sector decarbonisation and, by extension, economy-wide Net Zero emissions by 2050. Social licence issues can also impact the buildout of zero-emissions enabling infrastructure in non-electricity sectors (such issues being outside the scope of this report).

[11] AEMC, 2022, Transmission Planning and Investment Review – Consultation Paper, s3.2.1, p24

[12] This is noted by AusNet in its submission to the AEMC's Transmission Planning and Investment Review – Consultation Paper (p11): "The absence of fit-for-purpose NEM-wide community engagement and benefit sharing practices for transmission projects is arguably the most critical challenge to the timely development of transmission infrastructure required to enable the energy transformation". AusNet has recently faced social licence challenges for its Western Victoria Transmission Network Project.

[13] Social licence issues in the context of VNI West are discussed in https://www.aemc.gov.au/sites/default/files/2022-02/aemc_cost_est_accuracy_roundtable_16_feb_2022.pdf. AEMO's Draft 2022 ISP notes social licence can be an important influence on the timing and delivery of transmission investment under its various Optimal Development Paths.

AEMO's Draft 2022 ISP acknowledges the importance of social licence in terms of its impact on the ISP's Optimal Development Path (ODP). However, AEMO's Draft 2022 ISP did not seek to examine how social licence considerations would alter the timing and composition of its ODP. This then means social licence issues impact neither the determination nor the assessment of ISP-identified projects. As such, social licence considerations remain to be internalised within the economic regulatory framework.

Social licence can be a time-intensive exercise that is hard to win and easy to lose. Once lost, social licence is difficult to regain and the impacts of one project in the NEM may be detrimental to social licence for other projects elsewhere in the NEM, now and into the future. The regulatory framework does not currently accommodate the costs and process of building social licence as a central and necessary component of the transmission infrastructure development process.

In addition, environmental approvals process, heritage impacts, planning requirements, shortfalls in local equipment and skill availability, and other issues may result in delays as well as cost variations for a project.

2.3.5 Risk of inefficient cost outcomes

The scale of transmission investments required to deliver network infrastructure consistent with a Net Zero future is substantial. AEMO estimates that the actionable ISP projects in its Draft 2022 ISP alone will require circa $12.5 billion investment[14].

Consumers currently bear the bulk of the costs of the network development, paying off the investments via network charges in electricity bills over a number of decades. Even if changes to the risk and cost sharing arrangements are introduced, consumers are still likely to foot a significant portion of the costs.

It is vital that cost-efficient network investments are made, to protect consumers.

The RIT-T is used to assess costs and benefits of credible options and select the option which is expected to deliver the greatest net economic benefit. In practice, the accurate ex-ante estimation and assessment of project costs in the RIT-T stage can be challenging, particularly for large and unprecedented projects. This has recently been acknowledged by ElectraNet and TransGrid in the case of Project EnergyConnect (PEC), where significant capital cost increases of the preferred option were seen between RIT-T and CPA stages. Risk contingencies, social licence, input costs escalation, and project staging have been recognised as drivers that are not well reflected in initial estimates, and therefore contribute to leading increases of overall project costs throughout the regulatory framework assessment process[15]. The AEMC is considering whether a level of additional rigour may be required for cost estimates at the RIT-T stage to avoid inefficient cost outcomes.

---

14 AEMO, 2021, Draft 2022 ISP, p11, value in 2021 dollars.

15 AEMO presentation, AEMC Cost Estimate Accuracy Roundtable, 16 February 2022.

3 Current framework delivers Net Zero

The CEIG has asked Baringa to form a position on whether the current framework for network planning and investment is capable of delivering the network needed to accommodate new, low cost, clean energy investment required to achieve Net Zero emissions by 2050. Depending on the carbon budget constraints applied, it is expected that the NEM will need to decarbonise on a faster trajectory than many other sectors, achieving substantial emissions cuts in the 2020s and 2030s, ahead of harder-to-decarbonise sectors.

Baringa is of the view that **the current planning arrangements and economic regulatory framework do appear to be capable of delivering critical projects in line with an economy-wide Net Zero by 2050 ambition.** It is important to note that:

- This view depends on the national Net Zero emissions by 2050 target remaining in all scenarios of the ISP.
- This view is not carbon budget-specific and just reflects the target end-state (i.e., Net Zero emissions by 2050 target).
- The theoretical timeframes for the economic regulatory framework as it applies to actionable ISP projects have not yet been demonstrated. We believe the new process should be given a chance to be implemented.

The current economic regulatory framework does not readily support delivery of projects on a more ambitious emissions reduction trajectory than that in the ISP ODP (which currently achieves low emissions in the electricity sector by 2040). As long as the *Step Change* scenario (or a more ambitious scenario) is given the greatest weight as the 'most likely' scenario, we do not believe this is necessarily a shortcoming.

- The current framework is designed to deliver a NEM transition in line with the ODP in the latest ISP only. Delivery of major network infrastructure for a more ambitious transition is likely to be challenging under the national framework, particularly for anticipatory investments like REZs.
- While the Draft 2022 ISP ODP does not deliver a low emissions NEM until the 2040s (see Figure 3, below), it appears to align with a carbon budget for a <2°C future, consistent with the Paris Agreement. Consistent with this ambition, at appears to accommodate the additional demand resulting from electrification in other sectors, which is needed for economy-wide Net Zero.

There are nonetheless a number of related processes which may introduce delays to project delivery.

- Various issues outside of the economic regulatory framework design may introduce delays, including social licence hurdles, planning and environmental approvals, TNSP financeability concerns, and constraints in local equipment and skill availability.

- Cost blow-outs and other issues which could be perceived to give rise to cost-inefficient outcomes also threaten to weaken community confidence in the process, potentially resulting in further delays.

Given the multitude of risks of delay, **there is merit in considering further opportunities to shorten the timeframes in the economic regulatory framework as well as addressing these additional risks and concerns**.

The process for assessing, approving and developing projects which are not actionable ISP projects remains quite lengthy, and hinders the likelihood of these projects being built in a timely manner. This is not a core concern for developing the network on the Net Zero trajectory but is nonetheless important to ensuring TNSPs can augment their network.

3.1 Rationale for position

3.1.1 Planning for Net Zero by 2050

To develop the network infrastructure needed to facilitate an energy transition in line with achieving Net Zero by 2050, it is critical that network planning is aligned with achieving this target. As this target is economy-wide, it is important to determine the NEM's contribution to meeting this target, which might require the electricity sector to lead the rest of the economy's emissions reduction efforts. It is therefore important for network planning to consider the emissions reduction required of the NEM in order to contribute to the economy-wide goal of Net Zero emissions by 2050.

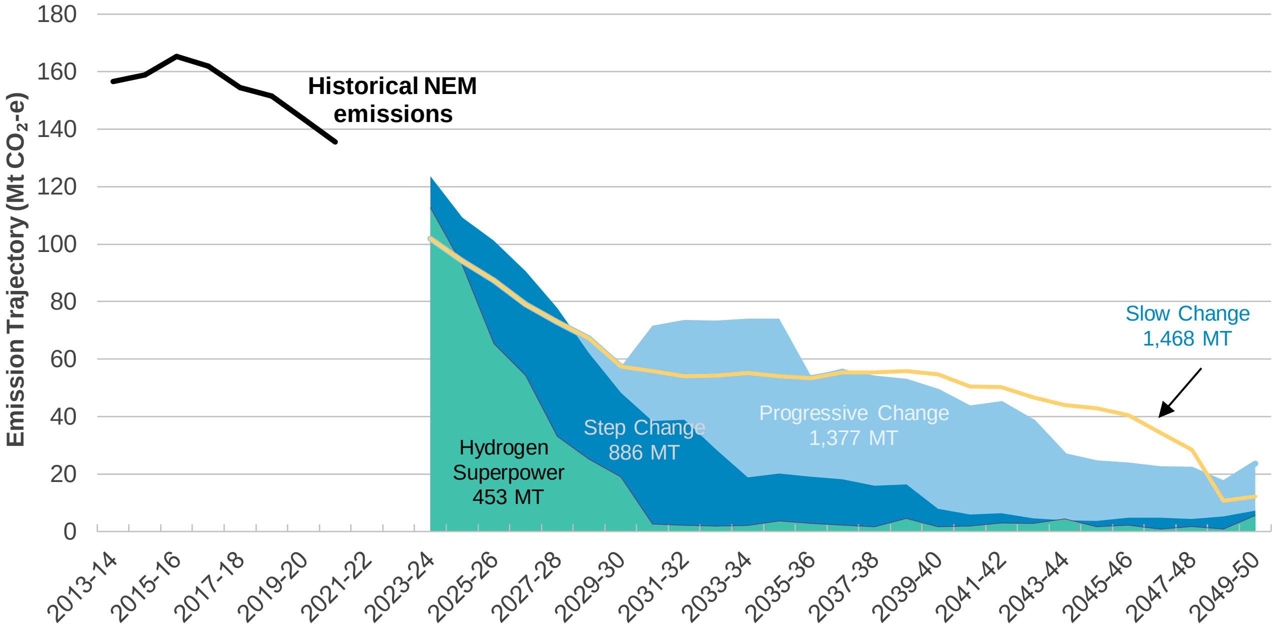
The ISP is a NEM-wide planning instrument and now underpins the development of major transmission network infrastructure through the national economic regulatory framework. The recent 'actionable ISP' reforms to the national framework aimed to improve the certainty and timing of achieving regulatory approval for projects that are required to meet ISP-identified system needs (projects on the ISP's ODP). Major transmission projects not included in the ISP, or progressed to a different timeline, will not benefit from this amended framework and there is less certainty that they will be developed as needed and in the timeframes required.

AEMO applies a complex and multifaceted methodology to develop its ODP. It essentially considers the merits of various candidate development paths under each of its scenarios and then weights the outcomes, with the 'most likely' scenario given the greatest weighting (50%). In AEMO's Draft 2022 ISP, all modelled scenarios align with achieving economy-wide Net Zero emissions by 2050.

The Draft 2022 ISP *Step Change* scenario is considered the most likely and therefore given the greatest weighting when developing the ODP[16]. As this scenario is aligned with a 1.8°C warming scenario, it achieves a steep reduction in NEM-wide emissions through the 2020s, and then more gradual reductions through the 2030s, finally achieving a very low (albeit not zero) emissions profile by 2040 (Figure 3).

[16] That is, the weightings are: Step Change 50%, Progressive Change 29%, Hydrogen Superpower 17%, and Slow Change 4%.

Figure 3: NEM-wide annual emissions under each Draft ISP 2022 scenario



Source: Baringa Partners analysis of AEMO data

Given the weighting placed on *Step Change* by AEMO in determining its ODP, the identity and timing of major transmission network projects in the ODP is fairly consistent with the identity and timings of projects under *Step Change* (Table 2). As highlighted in the table, the one divergence between the optimal timing under the ODP and under *Step Change* is for HumeLink, which occurs sooner under the ODP.

The ISP's ODP alignment with achieving Net Zero by 2050 (at least for Draft 2022 ISP; we consider this should also occur for the Final 2022 ISP and future ISPs) is consistent with the definition of each of the scenarios underlying Draft 2022 ISP. However, the ODP could go further and align with specific global warming scenarios; more precisely, CO_2-e budgets for the NEM that align with global warming scenarios of less than 2°C. This is discussed further in section 4.1.

Table 2: Optimal timing of major transmission projects in AEMO's Draft 2022 ISP

Major transmission project	Optimal Development Path (CDP12)	Slow Change	Progressive Change	Step Change	Hydrogen Superpower
Sydney Ring	2027-28	2039-40	2027-28	2027-28	2027-28
New England REZ Transmission Link	2027-28	2027-28	2027-28	2027-28	2027-28
CQ-SQ Stage 1	2028-29	2040-41	2030-31	2028-29	2028-29
QNI Connect	2032-33	2035-36	2036-37	2032-33	2029-30
New England REZ Extension	2035-36	2045-46	2038-39	2035-36	2031-32
HumeLink	Stage 1: 2022-23 Stage 2: 2026-27	2037-38	2035-36	2028-29	2027-28
Marinus Link (Cable 1)	2027-28	2034-35	2030-31	2027-28	2027-28
Marinus Link (Cable 2)	2029-30	2037-38	2032-33	2029-30	2029-30
VNI West	Stage 1: 2026-27 Stage 2: 2031-32	2040-41	2038-39	2031-32	2030-31
Gladstone Grid Reinforcement	2030-31	N/A	2035-36	2030-31	2028-29

Source: AEMO Draft 2022 ISP[17]

3.1.2 Approving projects for Net Zero by 2050

The economic regulatory framework which has traditionally applied for the development of major transmission projects, and which continues to apply to non-actionable ISP projects, has not had a direct link into a long-term NEM development plan and has not been suitable for developing anticipatory projects like REZs. As mentioned in Section 2, the process has also been slow and is unsuitable for developing major near-term projects.

Recent reforms to the planning and economic regulatory framework have addressed many of these shortcomings:

- The ISP provides long-term, NEM-wide and independent planning:
  - This is unique from the TNSP-led planning published in annual Transmission Annual Planning Report (TAPR) publications which is regional, shorter term (a 10-year planning horizon rather than 30-year), and informed by the TNSP's commercial interests.
- The ISP sets a pathway to meet government commitments (from an electricity sector perspective) alongside other market needs.

[17] See Table 8 (Optimal Development Path timing) and Table 9 (individual scenario timing assuming perfect foresight) from Draft 2022 ISP.

  - This includes achieving regional and national 2050 Net Zero commitments, when these are legislated or formalised through other means[18].
- The economic regulatory framework is now structured to deliver projects on the ISP ODP in the timeframes required to meet government commitments and other system needs.
  - TNSPs are required to commence a RIT-T for any 'actionable ISP' projects in their region as soon as practicable after the ISP is published, rather than leaving this to the TNSPs discretion.
  - The ISP defines the 'identified need' for major near-term projects, removing the uncertainty and risk of depending on the TNSP to demonstrate the need and the AER to approve it.
  - The RIT-T, as it applies to these major and near-term 'actionable ISP' projects, adopts a more streamlined process with stages occurring in parallel (as shown in Figure 2), allowing projects to progress to regulatory approval faster.
  - The use of a feedback loop allows for AEMO to lean on its existing modelling to test proposed project costs, rather than requiring duplicative analysis by the AER.
- The economic regulatory framework for transmission projects now enables anticipatory investments, in line with the ISP.
  - Traditionally, TNSPs have been required to demonstrate the need for a project on the basis of an anticipated increase in consumer or producer surplus, or otherwise[19]. In the case of REZs, in particular, the need case is largely based on anticipated increase in supply in a given region which is challenging to identify in the absence of generator commitments.
- As identified above, recent reforms allow AEMO to identify the need for actionable ISP projects, negating the need for TNSPs to demonstrate this anticipated need.

When TNSPs assess project options, actionable and anticipated ISP projects must form part of the RIT-T modelling assumptions, meaning that anticipated (but not currently committed) REZ developments can be assumed. These reforms have not yet been implemented, end-to-end, on any major transmission projects. It has not therefore been demonstrated that the process is able to deliver the certainty and timeliness it is proposed to achieve. However, based on the notable streamlining measures and removal of some duplication in the process, we think it is plausible that it will deliver projects which appear on the ISP ODP in, or near-to, the timeframes proposed. Further, the reforms should be given the opportunity to run their course before a judgement is made on whether they will or will not work.

[18] Policy is considered to be sufficiently developed for AEMO to identify its impacts on the NEM if: a commitment has been made in an international agreement; the policy has been legislated; there is a regulatory obligation in relation to the policy; material funding has been allocated to the policy; and/or the Ministerial Council has advised AEMO to incorporate it (NER 5.22.3 (b)).

[19] Specifically, the identified need may consist of an increase in the sum of consumer and producer surplus, reliability corrective action, the provision of inertia services, or the provision of system strength services. This is described in the AER's RIT-T Application Guidelines, with definitions in the NER.

3.1.3 Delivering projects for Net Zero by 2050

While the planning and economic regulatory frameworks now appear capable of delivering network infrastructure to facilitate the energy transition in line with Net Zero by 2050, there are likely to be broader challenges which need to be considered and mitigated.

In particular, gaining and maintaining social licence for the development of large transmission infrastructure across the NEM is expected to be an increasing challenge. Planning approvals, including environmental approval, as well as supply chain and labour constraints are also likely to present delays/challenges for some projects.

In the Draft 2022 ISP, AEMO notes that "some important considerations may still risk the Draft [ODP] timely implementation"[20]. In particular, AEMO flags that the land area needed to support the new network, generation and storage projects in the ISP is unprecedented, and that proactive community engagement and land-use planning are needed. It also notes that social licence considerations may lead to alternative developments which are less impactful, such as offshore wind development. AEMO also flags that project sequencing will be needed to manage supply chain risks which will come with the scale and rate of development.

Given these risks, it is important not only to look to any options to mitigate these wider risks, but also to identify any further streamlining opportunities in the economic regulatory framework itself, to reduce timeframes further and buffer against potential delays in other processes.

[20] AEMO, 2021, Draft 2022 ISP, p15

4 Proposed policy positions

The Net Zero-linked scenarios within the Draft 2022 ISP along with the 'actioning the ISP' initiatives are welcome reforms to the transmission regulatory framework. However, there remains scope to revise the network planning and economic regulatory frameworks to ensure they are fit-for-purpose to enable the transmission network to achieve Net Zero.

Baringa has considered opportunities for revisions in the current national frameworks which address some of the current challenges identified by the AEMC in its Transmission Planning and Investment Review, by stakeholders in their submissions to that Review, and which we have seen in our own experience of the market. Further, while we consider the current framework to be capable of delivering new transmission projects on fast-tracked timelines, we have considered opportunities to further reduce timeframes to account for the broader risks of delay. These challenges and areas for revisions are categorised as:

- Network planning;
- Assessment and costing of credible options;
- Accommodating social licence considerations and broader jurisdictional needs; and
- Responsibility for projects.

Opportunities to revise the existing framework were developed through Baringa research and workshopping options with the CEIG:

- Receiving advice from the CEIG on issues of concern to its members
- Reviewing all published submissions to the AEMC Transmission Investment and Planning Review consultation paper. These drew attention to the priorities and concerns of stakeholders, as well as options for resolving existing challenges.
- Reviewing AEMO's Draft 2022 ISP and submissions to the Draft 2022 ISP
- Workshopping with subject matter experts internal to Baringa. This process drew on the policy, regulatory and commercial expertise and experience of our team to identify and finesse potential opportunities.

Table 3 lists the objectives used to prioritise reform options and opportunities worthy of further consideration to deliver a more fit-for-purpose network planning and economic regulatory framework. Individual opportunities did not necessarily achieve all of these objectives, however they were taken into account when considering opportunities.

It is important to note our discussion in sections 4.1 – 4.4 does not consider every single possible option for reform to then apply the criteria in Table 3 to arrive at our preferred reform option. Rather, our discussion takes the following approach:

- First, we apply the criteria at our discretion to first arrive at a credible and comprehensive, yet inexhaustive, set of reform options

- Then, we discuss each option to sufficient detail
- Finally, we apply the criteria in Table 3 to determine our preferred option.

This approach balances brevity with detail by confining option identification and evaluation to a credible set of reform options.

Table 3: Objectives used to assess and prioritise transmission framework reform options

Criteria	Further detail
Delivering Net Zero by 2050	Consistent with delivering a Net Zero trajectory
	Enables delivery of a <2°C warming future
	Supports timely delivery of critical infrastructure
Better outcomes for consumers	Safeguards cost-efficient network investment outcomes
	Unlikely to increase net costs for new generation
Near-term viability	Limited or incremental reforms required
	Distinct from recent national proposals or reforms

4.1 Network planning

4.1.1 Net Zero in the ISP

Why a policy revision may be needed

As noted in Sections 2 and 3, the ISP now underpins transmission infrastructure development across the NEM. If the national planning and economic regulatory framework are to deliver the network infrastructure needed for a Net Zero future, it is imperative that Net Zero is embedded into the ISP in a way that can be translated into actual investment decisions about the nature and timing of new infrastructure. In practice, this means ensuring the ODP identified in the ISP is consistent with delivering Net Zero economy-wide by 2050, in turn consistent with Australian Federal and State Governments' commitments to this target.

Focusing on Net Zero can obscure the ultimate goal: limiting carbon emissions over a period of time, not just in any one year, in order to limit the extent of global warming. Achieving Net Zero is not sufficient; it is also important to consider the CO_2-e budget (i.e., the total amount of emissions).[21] Hence, we also consider the ISP, and system planning more generally, should consider scenarios that are consistent with CO_2-e budgets that seek to limit the extent of global warming to sub-'dangerous' levels, namely no more than 2°C, consistent with the Paris Agreement.

To illustrate these points, note all Draft 2022 ISP scenarios assume economy-wide Net Zero emissions by 2050. However, the CO_2-e budget differs between the scenarios and consequently so does the emissions reductions trajectory for the economy and in turn for the NEM. AEMO's *Hydrogen*

[21] This reflects the fact that global warming is impacted by the *stock* of emissions, not the *flow*. 'Net Zero' refers to the flow, but what determines the extent of global warming is the total amount of emissions in the atmosphere (i.e., the stock).

Superpower and *Strong Electrification* scenarios have a 1.5°C-consistent CO_2-e budget, resulting in a much faster and earlier decarbonisation of the NEM than *Slow Change*, which has a 4°C-consistent CO_2-e budget and hence slowest pace of decarbonisation.

It is therefore important to consider the need for additional measures on two fronts:

1. Ensuring Net Zero 2050 (economy-wide) remains a feature of the ISP and its ODP
2. Considering whether system planning in the NEM should also factor in the extent of warming by, for example, focusing modelling on, or giving higher weighting to, scenarios with relatively low CO_2-e budgets, especially those scenarios that limit the extent of global warming to less than 2°C, which would be consistent with Australia being a party to the Paris Agreement, which seeks to hold the increase in global average temperatures to below 2°C.[22]

Options to address this need
Options to ensure Net Zero, and ideally consistency with the Paris Agreement, is embedded in AEMO's ISP and in its ODP include:

- Government commitment-driven: Existing requirements for the ISP remain, retaining the current approach that AEMO must adopt government commitments as assumptions in its modelling. The onus would be on governments to introduce interim targets, or other carbon budget-related commitments, to see greater or additional emissions constraints embedded into network infrastructure planning.
    - Key advantages: Low administrative burden for the energy market bodies; does not require market bodies to consider or set economy-wide emissions reduction ambition, which is outside of their existing scope of responsibilities.
    - Key disadvantage: Strengthened emissions reduction ambition dependent on government commitments, which have proven politically challenging at a national level to date (noting this may change subsequent to the forthcoming election).
    - Alignment with objectives: This approach aligns with the objectives of delivering Net Zero and requiring limited reforms to the national framework. This approach aligns with enabling a <2°C warming future but only if government is assumed to introduce interim targets consistent with this ambition.
- AEMO assumptions guardrails: Requirements could be introduced into the Cost Benefit Analysis Guidelines[23] for the preparation of the ISP by AEMO, to require that the ODP is consistent with, and constrained by, CO_2-e budgets for the NEM (for example, consistent with a <2°C warming trajectory). As required by the Rules, the AER's CBA Guidelines must describe the objective that AEMO should seek to achieve through its selection of development paths for assessment and must include a framework for selecting the ODP[24].
    - Key advantages: Certainty that the ISP ODP will be consistent with both Net Zero and particular global warming scenarios; may be feasible to implement without either NEL or NER changes.

[22] The Paris Agreement also aims to pursue efforts to limit temperature increase to 1.5°C. For more details, see https://www.industry.gov.au/policies-and-initiatives/international-climate-change-commitments
[23] AER, *Cost benefit analysis guidelines: guidelines to make the ISP actionable*, August 2020.
[24] NER 5.22.5 (d)

- Key disadvantages: Energy market bodies may not be appropriate institutions to define either the economy-wide or NEM-specific emissions trajectory and CO_2-e budget, as Australian governments have not (yet) committed to emissions reduction targets linked to specific warming scenarios/ CO_2-e budgets. If adopting the <2°C trajectory, it may still be challenging for AEMO to assess alignment of its ODP with this trajectory given it is only considering NEM-wide emissions and its approach to developing the ODP with multiple scenarios will make it difficult to draw on the pre-determined carbon trajectories of individual scenarios[25].
- Alignment with objectives: This approach aligns with the objectives to deliver Net Zero by 2050 and to enable delivery of a <2°C warming future. However, it only partially aligns with the objective to require limited reforms, given it will require amending the CBA Guidelines.

- NEM decarbonisation directive: The National Electricity Objective could be updated to introduce a decarbonisation objective, requiring AEMO to act in the interests of this objective when developing the ISP (alongside the existing objectives concerning safety, quality, reliability, security and affordability)[26]. In practice, this would require AEMO to develop a view on the emissions trajectory and carbon budget for the NEM, to meaningfully incorporate this objective into its planning, which it has already done in its Draft 2022 ISP.
    - Key advantages: Consistent value placed on decarbonisation across all AEMO activities, and across energy market bodies in their decision making, may lead to more efficient outcomes.
    - Key disadvantages: Requires NEL amendments and therefore high administrative burden to implement; as above, energy market bodies may not be appropriate institutions to determine the emissions trajectory and carbon budget for either the NEM or economy-wide.

- Alignment with objectives: As above, this approach aligns with the objectives to deliver Net Zero by 2050 and to enable delivery of a <2°C warming future.

Preferred approach

The Government commitment-driven approach is Baringa's preferred approach to ensure the ISP is consistent with delivering Net Zero by 2050. This is on the basis that the responsibility for developing economy-wide emissions reduction trajectories and CO_2-e budgets remains with government under this approach (as has already occurred with government commitments to achieve Net Zero by 2050). We do not consider energy market bodies to be appropriate institutions to determine the emissions trajectory and carbon budget for either the NEM or economy-wide.

Although the Australian Government has not legislated its commitment, Australia's formal update to its Nationally Determined Contribution with the UN fits within the definition of a policy commitment in the NER.[27] As such, it is expected AEMO will continue to adopt Net Zero by 2050 as an assumption

[25] AEMO's ISP scenarios are adopted from CSIRO economy-wide modelling, which defines the carbon budget associated with each. However, the ODP considers multiple scenarios and its carbon budget is therefore harder to define.

[26] National Electricity Objective: NEL, Part 1, s7; AEMO obligation to have regard to the NEO: NEL, Part 5, s49

[27] NER 5.22.3 (b)

in the Final 2022 ISP and subsequent ISPs, and indeed in its other system planning processes, such as its ESOO and GSOO, without any changes to the Rules or Guidelines required to ensure this.

Because of the methodology used by AEMO to arrive at the ISP's ODP, it is important that *all* scenarios modelled in the ISP continue to align with Net Zero. AEMO analyses candidate development path options against all four scenarios. While the relative significance of the results under each scenario differs based on weightings[28], and all have an influence on the projects and timings in the final path. Provided all ISP scenarios are Net Zero-aligned, so will the resulting ODP.

A more critical consideration is whether the ODP is aligned with limiting global warming sufficiently. As noted above, the Draft 2022 ISP scenarios differed on the basis of CO_2-e budgets. The 'most likely' ISP scenario – *Step Change* – is based on a 1.8°C-consistent CO_2-e budget. Applying the scenario weightings in the Draft 2022 ISP to the individual scenarios would yield an ODP that is aligned with a warming scenario *greater* than 2°C.[29]

Carbon budgets and emissions reduction trajectories need to first be considered economy-wide and then sector-specific, and it is logical that setting such parameters is the responsibility of government. As and when governments' Net Zero commitments extend to commitments on CO_2-e budgets, these will be expected to be embedded into the ISP akin to how Net Zero has been embedded into the ISP.

4.1.2 Frequency of ISP publications

Why a policy revision may be needed

The ISP is currently a biennial publication. Given the rate of change in market conditions as the energy transition ramps up, there have been proposals that a more frequent ISP would be preferrable, to reduce the ISP-to-ISP changes and reduce the risk of investment decisions being made on the basis of outdated assumptions. This would be consistent with AEMO's Inputs, Assumptions and Scenarios Report (IASR) and the Electricity Statement of Opportunities (ESOO), which are annual publications, which are annual publications.

There are also reasonable arguments for the opposite direction of change, moving to a less-frequent publication of the ISP. In particular, a less frequent ISP could:

- provide the market with more certainty of near-term plans;
- reduce the risk of a new ISP being published midway through assessment of projects from the prior ISP; and,
- allow enough time for AEMO to undertake more detailed project assessment and CBA in the ISP process, reducing the need for a RIT-T (however, AEMO is likely to be less well-placed than a TNSP to undertake the more detailed analysis).

Options to address this need

[28] In the Draft 2022 ISP, AEMO selected its ODP by analysing viable candidate development pathways with both a scenario-weighted market net benefit assessment and a least-worst weighted regret assessment. The scenario weighting applied across both assessments are: Step Change 50%, Progressive Change 29%, Hydrogen Superpower 17% and Slow Change 4%.
[29] Assuming a linear relationship between warming and weighting, the implied warming scenario in the ODP is 2.07°C

The options for frequency of ISP publication, to provide certainty to generation investors and developers, and to support the timely development of network infrastructure, include:

- More frequent (annual) publication:
  - Key advantages: Reduction in inter-ISP deltas, for both the inputs and the outputs; consistent with other annual planning and forecasting publications.
  - Key disadvantages: This timeframe currently appears unfeasible to implement with the rigour AEMO currently applies to the biennial publication; annual publication could result in projects having to update RIT-T modelling, and potentially reapply the RIT-T after their PACR is published, in response to changes in the identified need for their project or changes in key inputs or assumptions in the new ISP publications, introducing delays[30].
  - Alignment with objectives: This approach would particularly align with the objective of being unlikely to increase net costs for new generation, if the reduction in inter-ISP deltas is found to improve certainty. However, it does not align with supporting timely delivery of network infrastructure given the risk of more frequent modelling revisions. This approach is also inconsistent with requiring limited reforms to implement, as it would require significant changes to the NEL, NER and subordinate documents and processes.
- Retaining the biennial publication:
  - Key advantages: Retaining status quo avoids the administrative burden of change, which would require revisions to the NEL, NER, Guidelines, methodologies and procedures; biennial publication is achievable at the current level of rigour.
  - Key disadvantages: Inputs and outputs may change materially between publications; this publication is still frequent enough that a new publication may be released while projects based on the prior publication are still working through the approvals process, potentially introducing delays due to the need to remodel.
  - Alignment with objectives: Relative to the other options, this approach aligns with the objective of requiring limited reforms to implement. It may also strike a balance between enabling timely network infrastructure delivery and not increasing net costs for generation.
- Less frequent (three-yearly) publication:
  - Key advantages: Could allow for a more distinct cycle of planning and development: a plan is published and the focus then shifts to approving and commencing delivery of all near-term projects in the plan, then the next plan is published with a new suite of near-term projects to focus on.
  - Key disadvantages: less-frequent publication than at present would amplify the ISP-to-ISP deltas and may see ISP updates needing to be released in the interim, to reflect material new information on the policy, economic, and/or technological front.

- Alignment with objectives: As the inverse of the first option (increase in frequency), this approach may result in higher net costs for new generation if the higher inter-ISP deltas

[30] NER 5.16A.4 (n)

create risk and uncertainty when securing project finance, but may result in more timely network infrastructure delivery. This approach will require significant reforms, including to the NEL, NER and subordinate documents.

Preferred approach

Retaining the status quo, with the ISP as a biennial publication, is Baringa's preferred approach at this stage. The administrative burden involved in changing the frequency of publication is likely to be extensive, given the broad range of legislative instruments and processes which reflect this timeframe, and appears to disproportionate to the anticipated benefits of this change.

Biennial publication appears to balance providing certainty to developers and investors (by establishing a manageable risk of inter-ISP deltas) with supporting timely delivery of network infrastructure (by ensuring enough time between publications that actionable ISP projects could progress the RIT-T with one set of assumptions). Given the relative recency of the ISP itself, there is not yet evidence that this balance is not being achieved through the current approach.

We note that the AEMC is required to complete a review of the ISP framework by 1 July 2025, which will present an opportunity to reconsider this issue[31].

4.1.3 Consistent adoption of ISP scenarios and assumptions

Why a policy revision may be needed

There has been a considerable program of work to integrate the ISP into the NER and guidelines, and the processes and decision making of the energy market bodies. Nonetheless, there remains scope to improve consistency of the scenarios and assumptions used under the national framework.

This is particularly relevant with the adoption of Net Zero assumptions in the ISP but the lack of emissions reduction objective in the National Electricity Objective (NEO). The NEO provides the mandate and decision-making objectives of all three energy market bodies in the NEM, and currently drives decisions with affordability, safety, reliability and security outcomes[32]. This means that, while AEMO is identifying an infrastructure planning trajectory which is consistent with steep decarbonisation of the NEM, the market bodies still do not have a mandate to make decisions with decarbonisation as an objective. This introduced a risk that decision making for the NEM is inconsistent with the planning framework, resulting in inefficiencies[33].

Options to address this need

The options we have identified for introducing greater consistency into how the energy market bodies adopt and apply the scenarios and assumptions which inform or are outputs of the ISP include:

---

[31] NER 11.126.10

[32] NEL, Schedule 1, s7. National Electricity Objective: "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity; the reliability, safety and security of the national electricity system."

[33] Recent examples of work in which this has been notable include the Physical RRO proposal as well as decisions and proposals concerning price signals, which were not made with an explicit focus on decarbonisation and fostering a favourable investment environment for renewable energy projects, which conflicts with the scale of new renewable energy the ISP identifies will need to be built.

- NEM decarbonisation directive: As identified in Section 4.1.1, the NEO could be amended to include a decarbonisation objective, requiring all market bodies to act in the interests of this component of the objective alongside the other components. Although this would not explicitly align the market bodies with the ISP assumptions, 'most likely' scenario or the ODP, it would ensure decarbonisation is taken into account across all decision making. This includes AEMO using the same warming-differentiated scenarios for its Electricity Statement of Opportunities (ESOO) and Gas Statement of Opportunities (GSOO), noting this was done in AEMO's 2022 GSOO.
    - Key advantages: Consistent value placed on decarbonisation across energy market bodies in their decision making, which may lead to more efficient outcomes.
    - Key disadvantages: Requires NEL amendments and therefore high administrative burden to implement, and not in scope for the current AEMC review; does not require alignment with ISP assumptions and outputs specifically (though will improve consistency); to implement this objective may require energy market bodies to analyse the emissions trajectory and carbon budget constraints for the NEM and economy-wide, which they are not currently well-placed to do.
    - Alignment with objectives: If the objective is defined with reference to the Paris Agreement or a <°2C warming-aligned carbon budget, this approach would deliver a Net Zero target as well as enabling a <°2C warming future. It may also be consistent with timely infrastructure delivery, given the potential additional certainties and consistencies of approvals in the case that all three market bodies and the ISP are delivering a similar mandate. However, it does not align with the objective to require limited reforms.
- AEMC decarbonisation directive: The Ministerial committee (currently the Energy National Cabinet Reform Committee) is able to issue statements of policy principles which the AEMC must take into account, alongside the NEO, in its reviews and Rule-making[34]. A statement requiring consideration of a decarbonisation objective, or requiring the ODP in the latest ISP be adopted as an assumption, would enable AEMC decision making to be more consistent with the ISP.[35]
    - Key advantages: this approach does not require legislative change (still requires Ministerial sign-off) and is less administratively burdensome than a NEO amendment; it may fall within the scope of potential action in the current or near-term AEMC reviews; and it presents an opportunity to be more specific in defining the consistency (e.g., consistency with the ODP) rather than a broad decarbonisation objective.
    - Key disadvantages: This approach would only impact AEMC decision making, and not the other energy market bodies.
- Alignment with objectives: Depending on how the Statement is defined, this approach also has the potential to deliver a Net Zero target as well as enabling a <°2C warming future. It

[34] NEL s88

[35] The AEMC has published a discussion paper on how climate change considerations impact its rule-making process and how decarbonisation policies and targets impact its assessment of the NEO, NGO and NERO. For more details, see AEMC, *Applying the energy market objectives*, 8 July 2019. This document was published before most Australian Governments had had Net Zero commitments, and so the AEMC may consider updating this document in light of these commitments.

may also improve the timeliness of delivering Net Zero network infrastructure by embedding decarbonisation into the AEMC's Rule making process, but this will not deliver the same cross-body consistency as a NEO amendment.

Preferred approach
Baringa views that both NEO amendments and a Ministerial Statement have merits and should be considered as options to improve consistency in the adoption of ISP scenarios and assumptions by the energy market bodies.

The Ministerial Statement is likely to be a more viable near-term option to specifically require the AEMC to adopt ISP consistency in its decision making. This would see rule change determinations and other reviews more consistent with the NEM planning trajectory, and may avoid cost inefficiencies resulting from inconsistent direction.

However, a Ministerial Statement will only inform the work of the AEMC and, in the longer term and when the appropriate forum arises, amendment of the NEO appears the obvious means to achieve consistency between the three market bodies in terms of valuing decarbonisation.

Relatedly, we recommend an **update to the AEMC's Applying the *Energy Market Objectives* paper**. Last published in July 2019, this paper discussed how climate change considerations impact the AEMC's rule-making process and how decarbonisation policies and targets impact its assessment of the National Electricity Objective and related Objectives. This paper was published before most Australian Governments had had Net Zero commitments, and so the AEMC should consider updating this document in light of these commitments. Such considerations can then feed through into AEMO's system planning processes such as the ISP, ESOO and GSOO.

4.1.4 Identification and assessment of non-network solutions

Why a policy revision may be needed
Under the national framework, TNSPs have typically considered non-network options alongside (poles and wires-based) network options when undertaking a RIT-T. The expectation to give fair consideration to non-network solutions is growing, and growing in relevance, as technology improvements mean a range of technologies are able to provide network services. There nonetheless remain concerns that the cost benefit assessment in a RIT-T will not provide a like-for-like assessment of the options, as well as ongoing concerns that TNSPs are incentivised to deliver capital-intensive network infrastructure solutions.

A new approach for the treatment of non-network solutions was introduced to apply to actionable projects, as part of the 'actionable ISP' reforms. When it publishes its draft ISP, AEMO is now required to request proposals from the market for non-network solutions which could meet new identified needs included in the draft ISP[36]. Upon receiving proposals, AEMO and the relevant incumbent TNSP then consider whether any of the proposed solutions meet, or are reasonably likely to meet, the identified need. For options deemed credible, the responsible TNSP is required to consider the non-network solution when it undertakes the corresponding RIT-T. If no credible

[36] AEMO's Draft 2022 ISP included a call for submissions for non-network solutions for two identified needs: the New England REZ Transmission Link, and reinforcing Sydney, Newcastle and Wollongong Supply.

options are identified through this process, the TNSP may, but is not required to, identify additional non-network options for assessment alongside network solutions in the RIT-T[37].

Given the scale of infrastructure investment required over the coming decades to facilitate the energy transition, it is vital that the network economic regulatory framework accommodates non-network solutions, to ensure the most cost-effective options are chosen irrespective of technology type. It may therefore be relevant to consider additional measures or different approaches to ensure the treatment of non-network solutions appropriately accommodates and values these options, on a level playing field with network alternatives.

Options to address this need
Options for ensuring the non-network solutions are appropriately accommodated in the network economic regulatory framework include:

- Status quo for actionable ISP projects: When projects are 'actionable ISP' projects, the TNSP will only be required to include non-network solutions in its RIT-T if identified as credible options after a consultation process based on the draft ISP.
    - Key advantages: Market input to identifying solutions may result in more innovative solutions rather than depending on the TNSP identifying these; AEMO is involved in assessing proposals, providing an independent perspective; retains commitment to streamlined process by leveraging the ISP process to narrow the options to be considered in a RIT-T.
    - Key disadvantages: Non-network solutions could be discounted from inclusion on the basis of a high-level assessment only, and therefore not included in and subject to robust consideration in the RIT-T alongside network alternatives.
    - Alignment with objectives: This option does not align with the objective to safeguard cost-efficient network investment outcomes for consumers, as there is a risk that cost-effective non-network solutions are rejected based on preliminary proposals only. However, it does align with timely delivery of network infrastructure.

- Greater consideration of non-network solutions: RIT-T proponents could be required to include the most credible non-network solution from the market sounding process in their RIT-T assessments, rather than this only being required if the solution is found to meet, or be likely to meet, the identified need when assessed by AEMO and the TNSP at ISP stage.
    - Key advantages: Non-network solutions would not be able to be dropped from consideration on the basis of a high-level assessment alone, and would be considered in a RIT-T.
    - Key disadvantages: Less streamlined (and less timely) approach which may see the same non-network solutions considered twice, in the ISP stage and the RIT-T stage, despite not being likely to meet the identified need.

- Alignment with objectives: This approach would be expected to safeguard cost-efficient network investment outcomes for consumers, by requiring non-network solutions are more rigorously assessed. However, this is at the expense of timeliness. This option would also require reforms to the NER and subordinate documents, to implement.

[37] NER 5.15A.3 (b) 7(ii)(B)

In this section, we have considered how non-network solutions are factored into the planning framework, given this is something which changed significantly for actionable ISP projects. However, we note the approach taken to benefits assessment will also impact the treatment of non-network solutions – for example, non-network solutions may offer benefits in terms of minimising impacts on communities (in turn making it easier to obtain social licence), having a lesser impact on the physical natural environment, and providing optionality for future service provision, which may be missed or underrepresented without amendments to the ISP and RIT-T benefits assessments.

Preferred approach
Baringa's preferred approach is to retain the status quo approach to non-network solutions to address 'actionable ISP' identified needs. While this does present the risk that non-network solutions are disregarded without robust assessment alongside network options, the assessment of proposals by AEMO and the TNSP is based on whether proposals are 'likely to meet' an identified need, rather than based on cost or detailed design information.

Further, a lot of work has gone into reducing the overall timeframes for projects to achieve regulatory approval. As identified earlier in this report, Baringa's view is that there is a need to find further opportunities for streamlining, given the remaining risks to project delivery timelines due to social licence, environmental and planning approvals, and other sources of delay. Retaining the status quo arrangements for considering non-network solutions is consistent with streamlining the process.

4.2 Assessment and costing of credible options

The RIT-T is an identification of system needs (for non-actionable ISP projects) and an assessment of credible options, to arrive at a preferred option which meets the identified need and maximises the net economic benefit. In arriving at its preferred option for meeting identified needs, the ISP is subject to 'decision rules' which incorporate the latest information about future demand, supply, and technology costs (including transmission build costs) to ensure continued selection of options that maximise customer net benefits.

There are ongoing concerns about duplication between the ISP, RIT-T and CPA stages, which are incrementally more detailed in their assessment of project options. Baringa is of the view that the RIT-T has unique and important functions, and should remain a discrete step in the process. To remove the RIT-T, as has been proposed by some stakeholders, would either remove an important step in the process or would require the ISP assessment of projects to be enhanced to adopt the rigour of assessment currently in the RIT-T. It is unlikely that AEMO is the best placed to undertake this assessment, and it would also require a more time-consuming ISP.

However, there may be opportunities to reduce duplication and improve timeliness.

4.2.1 Streamlining of benefits assessment in the RIT-T

Why a policy revision may be needed
The benefits assessments undertaken by AEMO for the ISP include only the material, quantifiable, economic market benefits. The NER requires AEMO to consider a range of market benefits as part of preparing an ISP, with the benefit categories/classes within this range set out in the NER and also in

the AER's CBA Guidelines.[38] Competition benefits are one type of market benefit referred to in the NER and CBA Guidelines. However, AEMO has excluded competition benefits in its CBA to determine the ODP in the 2022 ISP, following concerns cited by a range of stakeholders about the complexity, uncertainty, and sensitivity of AEMO's proposed approach to quantifying competition benefits.[39]

In undertaking the RIT-T, TNSPs are required to include these same benefits but may also expand to include additional material market benefits if they determine them relevant to include, and if agreed in writing with the AER.[40]

Given the requirement for the TNSP to consider the same benefits in the RIT-T as considered by AEMO in the ISP, there is risk of duplication between the two processes.

Options to address this need

- Status quo benefits assessment: The current approach to calculating and assessing net economic market benefits of each option in a RIT-T requires that TNSPs consider those benefits in the ISP modelling and allows for the quantification of additional benefits.
  - Key advantages: This approach requires some consistency between the ISP and RIT-T but allows for some flexibility and discretion by the TNSPs, which can independently calculate and/or verify the anticipated benefits of an option.
  - Key disadvantages: This approach introduces the risk of duplication, with both AEMO and the TNSP required to undertake a benefits assessment.
  - Alignment with objectives: This approach is inconsistent with the objective to support timely deliver of critical infrastructure, as it retains duplication. However, it is consistent with requiring limited reforms to implement.
- Removing the requirement for benefit modelling in the RIT-T: It could be taken as an assumption in a RIT-T that all projects being considered to meet the identified need will deliver the market economic benefits modelled by AEMO as arising from meeting that need. TNSPs could then choose whether to model the incremental benefits of an expanded scope of market benefit categories, or could simply calculate the relative costs of different credible options and adopt the AEMO benefits standalone.
  - Key advantages: This approach would reduce duplication between the ISP and RIT-T and may lead to a faster RIT-T; alignment with AEMO's feedback loop which is focused on remodelling the ODP with the costs of a preferred option.
  - Key disadvantages: This approach would discourage the consideration of a wider suite of market benefits, given the additional time required to do this versus the efficiency of just adopting AEMO benefits assessment.
  - Alignment with objectives: This approach aligns closely with the objective to support timely deliver of critical infrastructure, by reducing duplication between the ISP and RIT-T. However, it is not aligned with the objective to require limited reforms, as it

[38] AER, *Cost benefit analysis guidelines: guidelines to make the ISP actionable*, August 2020.
[39] AEMO, Competition benefits in the ISP – Consultation Summary Report, December 2021. The 'sensitivity' point arises when bidding behaviour assumptions are made, or required to be made, on specific named generators, such as Snowy Hydro's generators when assessing the competition benefits of HumeLink.
[40] AER, RIT-T Application Guidelines, s3.6.2

would require revised Rules and subordinate documents. These reforms would be expected to be relatively minor, given they are removing rather than adding requirements.

- Narrowing the requirement to non-market benefit assessments in the RIT-T: As a variation on the above approach, the requirement to include market benefits assessment could be removed from the RIT-T framework on account of reducing duplication. However, RIT-T proponents could be required, instead, to undertake a non-market benefits assessment of each credible option, with guidance on benefits areas to consider, including social licence benefits and environmental benefits. For these benefits to be feasibly evaluated alongside the project costs and AEMO-determined project benefits, they would need to be quantified.
  - Key advantages: This approach would reduce duplication between the ISP and RIT-T; the wider range of benefits which can be considered in this option may align more closely with the expectations of jurisdictions and consumers; non-network solutions and other proposals which may deliver more sustainable outcomes (for example, infrastructure options with lesser community or environmental impacts) may be better positioned to compete with traditional network solutions.
  - Key disadvantages: This approach would not improve the timeliness of the RIT-T, as it removes one element of benefits assessment but adds another. It will also be challenging to implement consistently and robustly in practice, given the non-market benefits are harder to quantify and – if not quantified – harder to evaluate alongside quantified costs and benefits.

- Alignment with objectives: This approach has the potential to safeguard more cost-efficient outcomes for consumers, if it results in different preferred option outcomes which deliver material non-market value for consumers. However, it is not aligned with the objective to require limited reforms, as it would require revised Rules and subordinate documents, including considerable work on the quantification of non-market benefits.

Preferred approach

Baringa's view is removing the requirement to undertake a benefits assessment in a RIT-T for an actionable ISP project merits further consideration. This option has the potential to reduce duplication and to reduce timeframes for the RIT-T. While there are potential downsides to disincentivising an independent benefits assessment or inclusion of non-market benefits categories, other measures such as the proposed jurisdictional needs, below, may offset some of this downside.

Furthermore, we recommend AEMO include competition benefits in its CBA to determine the ODP in future ISPs, including 2022 Final ISP. Taking account of stakeholders' concerns about the complexity and uncertainty of assessing competition benefits, we recommend the following two-step approach to incorporating competition benefits:

1. AEMO determine the ODP excluding competition benefits, as it has done in 2022 Draft ISP
2. AEMO then check the extent to which the timing, identity, and/or magnitude of network augmentations in its ODP is impacted by the inclusion of competition benefits – with AEMO having the discretion to adjust its ODP if it assesses this impact to be material.

We note AEMO applied the above approach to assessing the impact on the HumeLink part of the ODP in its Draft 2022 ISP. It is not clear why competition benefits should only apply to HumeLink and not to the other projects within the ODP, and as such we recommend the above two-step approach be applied to the full network development pathway within the ODP.

Furthermore, we do not consider there should be an expansion of the scope of benefits in the NER and in the AER's CBA Guidelines, to include benefits related to employment or incomes, though as discussed in section 4.1 we do consider the scope should be expanded to include emissions benefits (and/or disbenefits as and where relevant). In our view, employment and income impacts *are* important, but quantifying and monetising such impacts are best left to governments rather than market bodies, since such impacts need to take both winners and losers into account and so may have implications for social and employment policy (e.g., unemployment benefits, retraining assistance) that is the responsibility of governments.

Where government(s) want an evaluation of employment and/or income impacts and benefits from network augmentations, this can be done by integrating jurisdictional needs alongside AEMO's identified needs for actionable ISP projects. We discuss this further in section 4.3.

4.2.2 Quality of cost assessment in the RIT-T

Why a policy revision may be needed

The network economic regulatory framework is used to assess and approve billions of dollars of infrastructure investment, to be recovered from consumers over decades. The level of investment required to deliver the ODP in the Draft 2022 ISP is estimated by AEMO to be in the order of $12.5 billion[41].

It is important to protect consumers from paying more than is required for the energy transition, by ensuring the option selected through the RIT-T and approved through the CPA has been robustly assessed and is indeed the most cost-effective and appropriate option. Further, it is important that the proposed costs at the RIT-T and CPA stage, which inform the final decision, are not unreasonably exceeded as the project progresses[42].

Measures have been introduced and backstop options implemented over recent years to require or enable TNSPs to undertake a greater level of detailed project analysis and design work earlier in the RIT-T and ahead of finalising their contingent project applications for developing major new infrastructure. This has been aimed at ensuring that cost assessments used in the RIT-T are informed by a more detailed understanding of the project. These measures include:

- requiring TNSPs commence preparatory activities for actionable ISP projects as soon as practicable after an ISP is published;

[41] Network investment identified as actionable in the ISP is ~$12.5 billion in today's value – AEMO, Draft 2022 ISP, p11.
[42] This is important because the costs approved at the CPA stage have been confirmed to still place the project on the Optimal Development Path and any material increase in costs could draw this into question after consumers are already committed to funding the project. This is also important because if the cost increase causes the TNSP to overspend relative to their total capital and operational allowances, consumers will bear some of these costs (based on existing cost-sharing arrangements).

- enabling AEMO to require that REZ Design Reports are developed ahead of proposed REZs being developed, which entails undertaking some preparatory activities;
- enabling AEMO to require that preparatory activities are undertaken for future ISP projects;
- formally staging selected projects in the ISP, with the first stage being early works;
- enabling contingent project applications to be stages, such that the funding for early works for a RIT-T preferred option can be approved first through an early works-specific CPA, and this work then carried out and used to inform the subsequent CPA for the broader project costs[43]. TNSPs can use this option at their discretion, and are expected to find it of value for particularly large and unprecedented projects for which the costs are challenging to forecast; and
- ad hoc government underwriting of the costs of early works, to de-risk their early progression ahead of securing revenue certainty to recover the costs.

These measures may help to enable, incentivise or require more detailed project analysis (preparatory activities) earlier in, or ahead, of a RIT-T. In doing so, they may help to improve the quality of cost assessments used to compare options and to assess a final option for approval. The measures in place may also help to enable more costly and detailed early works for a RIT-T preferred option ahead of finalising the CPA and seeking approval for the project, which is expected to improve the accuracy of final approved costs. These improvements could address the risk that the initial costs used to assess and approve projects lack rigour and could result in a suboptimal project progressing, and the risk of costs substantially increasing post-approval.

Given the scale of investment required to finance the NEM transition, it is nonetheless considering further means by which the risk of cost increases and inefficient cost outcomes could be further reduced, to safeguard consumers.

Options to address this need
Further options to enable a higher quality and accuracy of costs assessments in the RIT-T and the CPA include:

- Mandating a review of recent reforms: Recent reforms, and the AER's guidance on contingent project staging, are intended to reduce the financial risk to TNSPs of undertaking costly early works ahead of finalising their CPAs. A near-term formal review of the outcomes of the reforms could be mandated, to consider whether the new approach has been used and what the outcomes have been in terms of rigour of cost estimates (to the extent this is assessable by then) and whether the dependence on government underwriting has been alleviated. In the case that the outcomes do not demonstrate improvements, this would be grounds on which to consider amendments or alternative arrangements.
    - Key advantages: No immediate reforms required and recent reforms are given a chance to be implemented.

[43] AER, 2021, Guidance Note: Regulation of actionable ISP projects, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulation-of-large-transmission-projects/final-decision

- Key disadvantages: This approach does not address any near-term deficiencies in the current approach, if these do materialise.
- Alignment with objectives: This approach may align with the objective to safeguard cost-efficient network investment outcomes. However, this outcome will only be delivered if there are flaws in the initial implementation which are picked up and improved on via the review. The introduction of a mandatory review will require some reforms, to introduce the requirement and to provide terms of reference.

- Requiring staged CPAs for large projects: Currently, for projects which are not identified as staged in the ISP, TNSPs still have the opportunity to progress the CPA in stages after the completion of the RIT-T. This allows them to progress a CPA for early works, securing funding, ahead of finalising their CPA (and costs) for the broader project. After completing these early works, if the TNSP identifies that the project costs are forecast to be higher than those in the RIT-T, the feedback loop process must be repeated with the new costs to ensure the project (and its higher costs) continues to sit in the ODP. Given the merits of this process - ensuring more rigorous work is done (with certainty of funding) to define a project and its costs ahead of securing final approval and ensuring that post-early works costs are considered through the feedback loop - it could be introduced as a requirement for all large projects. 'Large' could be defined with a cost forecast threshold coming out of the RIT-T.
  - Key advantages: This approach would ensure the post-early works costs are confirmed to be in line with the ODP before approval via the CPA, thus ensuring they are in line with delivering efficient outcomes for consumers and are less likely to increase post-CPA. Although this is possible irrespective, by ensuring TNSPs have secured cost recovery for the early works there may be greater certainty that this work will be completed with rigour.
  - Key disadvantages: This approach would increase the administrative burden of the CPA process and of progressing projects to regulatory approval, and therefore may increase timeframes; this approach would not resolve concerns about cost increases between RIT-T and CPA (and may exacerbate this) and would not see the RIT-T preferred option re-evaluated against other credible options.
  - Alignment with objectives: This approach aligns with the objective to safeguard cost-efficient network investment outcomes for major projects. There is a risk that it does not align with the objective to support timely delivery of critical infrastructure, given the additional administration required of two CPAs rather than one. Making staged CPAs mandatory for some projects will require reforms, however the framework for implementing the staged approach already exists.
- Stronger requirements for REZ Design Plans and preparatory activities for future ISP projects: Under the Rules, AEMO may require that a REZ Design Report is prepared by a Jurisdictional Planning Body for a REZ identified in the ISP to be developed in the coming 12 years[44]. In preparing a REZ Design Report, the Jurisdictional Planning Body must undertake preparatory activities and must undertake community consultation, assessing key community impacts and estimating the costs of addressing the impacts. Similarly, the Rules allow the ISP to specify that preparatory activities must be undertaken for other future ISP projects[45]. The

[44] NER 5.24.1(a)(3)
[45] NER 5.22.6(c)

Rules could be strengthened to require that REZ Design Reports will be developed ('must' rather than 'may') and could prescribe timeframes around when these will be required.

- Key advantages: This approach is expected to result in more accurate cost assessments for REZs and for other future ISP projects; it may reduce timeframes for the RIT-T for these projects, given preparatory activities will have been undertaken in advance of the RIT-T commencing. It would also leverage the benefits of the existing REZ Design Report framework and ensure preparatory activities and initial costing of some elements is undertaken for all REZs, ahead of their entering the network economic regulatory framework.
- Key disadvantages: Preparatory activities undertaken well in advance of a project becoming actionable may need to be revised during the RIT-T, if conditions have changed; the REZ Design Reports and preparatory activities for future ISP projects are already an option in the Rules, and changing them to a requirement may not deliver additional benefits if AEMO intends to require them anyway.

- Alignment with objectives: This approach aligns with the objective to safeguard efficient network investment outcomes for major projects, by increasing the amount of pre-work that informs the RIT-T assessment. This approach may also achieve the objective of supporting timely delivery of critical infrastructure by initiating community engagement early.

Another approach identified in the course of this review was to formalise the role of governments – either state or federal, in underwriting and de-risking early works. Government underwriting of this financial risk has been implemented for major projects on an ad hoc basis to encourage the responsible TNSPs to progress the early works ahead of securing certainty of cost recovery. We have not included this as an option here, given it is not clear that this should be a role for governments, and we do not believe that formalising this approach is likely to gain traction with governments as an ongoing measure.

Preferred approach
We consider that all three options proposed are worth consideration.

The mandated review of the recent reforms to enable early works, such as the AER contingent project process, merit review after they've had time to prove their potential, prior to making an evidence-based assessment of additional reforms.

Introducing a requirement for staged CPAs for projects that exceed a threshold level of investment would be a more material and potentially riskier reform, however it has the potential to act as a safeguard for consumers by ensuring that the post-early works costs are subject to the feedback loop and consistent with the ODP. This approach is worth considering further in consultation with TNSPs and the AER, including consideration of how it would impact overall project delivery timeframes.

For REZ projects and other future ISP projects, the option to require and more clearly prescribe timeframes for the development of REZ Design Reports and the undertaking of preparatory activities is worth considering. Our view is that, while the additionality of this option is not yet clear (as AEMO may have requested REZ Design Plans and preparatory activities anyway), it is a low risk means of ensuring the activities are undertaken early and that community consultation is commenced ahead of the project becoming actionable.

4.2.3 Feedback loop

Why a policy revision may be needed

The feedback loop, to assess the costs of the preferred option identified in a RIT-T in the context of the ODP modelled by AEMO, is integral to the actionable ISP process.

- It enables cross-checking of the cost-effectiveness of the preferred network (or non-network) option against the ODP once a more granular cost estimate has been undertaken by a TNSP, and thus serves a consumer protection purpose of checking if a project remains beneficial to consumers even under the more granular cost estimate.

- Further, the feedback loop is a streamlining measure, to reduce duplication and overall timeframes in the economic regulatory framework. By giving AEMO responsibility for checking the efficiency of the preferred option using its existing model, it removes the need for the AER to undertake independent assessment of costs at the CPA stage, for which it would typically engage independent consultants.

However, we understand AEMO has raised concerns about the practicality of implementing this measure[46]. In particular, it is challenging to undertake the significant modelling exercise required to implement the feedback loop while continuing to progress the ISP to required timelines. Further, the time taken to undertake a feedback loop may delay the progress of the RIT-T and CPA. Despite these concerns, we note AEMO has undertaken two feedback assessments in the last two years – HumeLink early works[47] in January 2022 and VNI West[48] in November 2020. AEMO published its notices confirming the proposals remained in the ODP within one week of receiving the request for the HumeLink project and within one month for the VNI project.

Given AEMO's concerns, however, and the benefits of reducing the risk of delays to the process, it is nonetheless worth considering options to revise the feedback loop and how it is applied.

Options to address this need

Options to revise the feedback loop to reduce potential delays to the overall process include:

- Proactive assessment of maximum costs: as a means to reduce the risk of delays in the RIT-T and CPA process (and potential delays in ISP progress) due to feedback loop modelling, a proactive approach to assessing project costs could be adopted. As part of its initial ISP modelling, AEMO could be required to calculate the maximum cost which could be permitted for meeting each actionable ISP 'identified need' before it would no longer form part of the ODP. This value would essentially act as a cap on costs, similar to that proposed to be introduced in NSW under its bespoke network development arrangements. If the proposed

[46] AEMO submission to the AEMC Transmission Planning and Investment Review consultation paper, https://www.aemc.gov.au/sites/default/files/documents/aemo_8.pdf

[47] AEMO, 2022, ISP Feedback Loop Notice – HumeLink (early works), https://aemo.com.au/-/media/files/major-publications/isp/2022/isp-feedback-loop-notice-humelink-early-works.pdf

[48] AEMO, 2020, ISP Feedback Loop Notice – VNI West, https://aemo.com.au/-/media/files/major-publications/isp/2020/isp-feedback-loop-notice-vni-minor.pdf

cost of a preferred option, as calculated by a TNSP, is below the cap value, AEMO would not need to undertake additional modelling to approve the project as aligned with the ODP.

  - Key advantages: This approach may reduce the risk of delaying the CPA and the subsequent ISP, by removing the need for remodelling once a preferred option is selected.
  - Key disadvantages: This approach would likely require the maximum cost values to be confidential between AEMO and the AER to avoid anchoring TNSP cost estimates, which will come at the detriment of transparency; implementation may become complicated if assumptions change between those used in the initial ISP for its maximum cost assessment, those used in the project's RIT-T, and those adopted by AEMO at the time the CPA comes around.
  - Alignment with objectives: This approach is likely to align with the objective to support timely delivery of critical infrastructure. However, this outcome depends on the extent of delay which would otherwise be incurred if the feedback modelling were undertaken after a RIT-T (precedent suggests this ranges from a week to a month). This approach would require reforms to change the timing and nature of the feedback loop, therefore not entirely aligning with the objective to limit reforms.

- Threshold for remodelling: The application of the feedback loop could be revised to provide greater flexibility on when modelling is required. For example, the feedback loop could be applied only when cost estimates exceed the initial ISP cost estimates by a threshold amount. If the cost assessment of the preferred option in a RIT-T exceeds the initial cost estimates by AEMO within a predefined margin, AEMO could have the option to confirm that the preferred option still aligns with the ODP without undertaking a feedback loop[49].
  - Key advantages: This approach may reduce the risk of delaying the CPA when cost estimates are under or close to the AEMO costing.
  - Key disadvantages: risk of this latter option is that a significant investment may be approved even though it is no longer an efficient investment on the ODP, with consumers bearing this cost.

- Alignment with objectives: This approach would align with the objective to support timely delivery of critical infrastructure for those projects whose costs exceed corresponding ISP costs within the threshold. The extent to which this outcome improves timeliness depends on how long the avoided feedback modelling would have taken. However, there would be no improvement for timeliness for projects whose cost 'deltas' exceed the threshold, though it does then reduce the risk of costly network investment outcomes by avoiding the possibility of a project being approved via a CPA which would not remain in the ODP based on its costs.

[49] NER 5.16A.5(b)

Preferred approach
Baringa's preferred approach to amending the feedback loop is to introduce a proactive assessment of maximum project costs by AEMO. This could be used to identify whether a preferred option in a RIT-T would be expected to remain on the ODP based on its updated cost assessment, without needing to undertake extensive remodelling.

4.2.4 Adherence to timeframes

Why a policy revision may be needed
As noted in Section 2, the recent 'actionable ISP' reforms have streamlined the economic regulatory framework for actionable ISP projects as identified by AEMO. However, these timeframes have yet to be demonstrated through application to a project, end-to-end.

Baringa's view is that these recent reforms and the streamlined process should be given the opportunity to play out before a judgement is made on whether or not they can achieve the timeliness they purport to.

Nonetheless, measures should be considered to provide greater confidence to the market and to consumers that the proposed timeframes will be met, and to strengthen the imperative for market bodies to meet them.

Options to address this need
Options to provide more certainty around adherence to timeframes include:

- Removing timeframe extensions for 'actionable ISP' projects: The Rules currently require that the AER make a decision on a contingent project application within 40 business days from receiving the application (or from receiving additional information)[50], but allow the AER to extend this timeframe by up to 60 business days if it believes the proposal involves issues of such complexity or difficulty that the extension is needed[51]. For 'actionable ISP' projects, an additional layer of analysis has already occurred through the ISP, and the application of the feedback loop has likewise acted as a safeguard for cost efficiency, which should reduce the need for more extensive scrutiny by the AER. As such, removing the potential to extend the timeframe for 'actionable ISP' projects may be appropriate.
    - Key advantages: This would reduce the risk of delay in the CPA process and may provide reassurance to TNSPs and other stakeholders of the timeliness of decision making.
    - Key disadvantages: The AER would lose the option to take more time for assessments it deems complex or difficult, and would be required to make rushed decisions in these instances which may lead to suboptimal outcomes for consumers.
    - Alignment with objectives: This approach aligns with the objective to support timely delivery of critical infrastructure, by ensuring the CPA decision is made within a narrow window of time. However, it does not align with safeguarding cost-efficient network investment outcomes for consumers, given it risks rushing the AER and preventing it from thoroughly considering an application, even if complex. This

[50] NER 6A.8.2(d)
[51] NER 6A.8.2(i)

approach would require a minor Rule amendment to implement, aligning partially with the objective to require limited reforms.

- Introducing an oversight role: The introduction of an oversight role to monitor compliance with timeframes may provide a stronger impetus to meet timeframes prescribed in the Rules and other documents. This oversight role could involve reporting on any missed deadlines and lessons learnt to ensure the reason for any missed deadlines are understood and the risk reduced in the future.
    - Key advantages: This option does not seek to reform the process, but to ensure it is more likely to be adhered to.
    - Key disadvantages: This option would introduce administrative burden, and may not have a notable impact on timeframes given it has not been demonstrated that the market bodies will routinely fail to meet prescribed timeframes.

- Alignment with objectives: This approach aligns with the objective to support timely delivery of critical infrastructure, by introducing a process to ensure improved implementation over time. The extent to which it delivers this objective depends on whether the energy market bodies are assumed to otherwise not meet their prescribed timeframes. This approach would require limited reforms to implement.

Preferred approach
Baringa's view is that the oversight role is worth introducing to – at a minimum – provide a formal mechanism for identifying and learning from any shortfalls in the current process which result in delays. At best, this approach may also increase the impetus to adhere to prescribed timeframes and may reduce the risk of delays.

While we do see merit in removing the AER's power to extend the decision-making timeframe for CPA approvals, there are significant risks to this option. Removing the option to properly scrutinise and assess proposals which involve millions of dollars of consumer-funded infrastructure investments, when identified as complex or difficult, appears to risks resulting in suboptimal decisions at a cost to consumers.

Instead, the scope of a new oversight role could include assessment of any instances in which the extension was used by the AER in a CPA, to understand and learn from the experience and ideally reduce the use of this mechanism over time.

4.2.5 Summary

In summary, our policy positions and recommendations represent appropriate modifications to the set of 'decision rules' under the ISP, that balance the following at times competing considerations:

- certainty for investors in relation to the location and timing of transmission network augmentations: investors in generation, storage and, increasingly, transmission network infrastructure[52]

[52] Private sector (or at least non-incumbent TNSP) investor ownership and control of transmission network infrastructure is discussed in section 4.4.2 (network contestability).

- maximising net benefits for consumers who, ultimately, pay for most, if not all, of transmission network infrastructure identified as optimal under the ISP, and
- reducing duplication between the ISP, RIT-T, and CPA, and
- increasing timeliness of project delivery by shortening the timeframes between system planning, project design and then delivery.

These considerations, which can be competing tensions, and need to strike a balance between them also feature in our policy positions and recommendations in the following parts of Chapter 4.

4.3 Accommodating social licence initiatives and broader jurisdictional needs

Building and maintaining social licence for renewable energy and transmission projects, across the whole community and particularly in regional Australia, is crucial to the energy transition. Community support is not only important to the timely progress of a given project in the immediate term, but is also important to the delivery of future transmission, generation and storage projects which will rely on positive community sentiment towards electricity infrastructure.

The national economic regulatory framework for transmission investment is based on economic efficiency considerations, and the traditional capital and operational costs of infrastructure build. Without specific measures to accommodate social licence initiatives and broader environmental and planning considerations, the framework may undervalue these initiatives and considerations or make recovery of the associated costs a challenge.

Currently, robust community engagement (and the costs involved with this) tend to occur largely after the transmission planning and investment process is complete under the national framework, as part of the jurisdictional planning process. In the Draft 2022 ISP, AEMO noted that “the sector continues to underestimate the time and money that community consultation requires, with the rules placing it ‘at the back end’ rather than the front of the process”.[53]

Given the impact that community engagement and social licence, as well as the broader planning and environmental approvals processes, can have on the timely and progress of a project, it is a shortcoming of the current framework that these aren’t taken into account in the earlier stages of project assessment.

4.3.1 Quantitative assessment of social licence in the ISP

Why a policy revision may be needed

There is increasing acknowledgement of the significance of social licence in delivering the energy transition. AEMO acknowledged the potential social licence challenges of delivering the ISP projects given the scale of infrastructure required, as noted in the Section 4.3 overview above, and community outcomes have been highlighted by state government REZ policy documents[54].

[53] AEMO, 2021, Draft 2022 ISP, p89

[54] Communities and local economies are important considerations in the NSW Government Electricity Infrastructure Roadmap and the supporting legislation, and have been flagged as important by both Victoria and Queensland in preliminary REZ documents.

Despite the growing awareness of the need for early and ongoing community engagement, and the importance of social licence, this is not yet reflected in the national planning and investment framework. In particular, the costs and timeframes for building and maintaining social licence, and the cost and delay that comes with failing to garner community support for projects, are not currently central considerations in ISP modelling or in the RIT-T.

In its submission to the Draft 2022 ISP[55], *Star of the South* argues that, though there is significant uncertainty as to the limits of social licence, it is clear that constraints are correlated with such factors as:

- the value of land for competing non-energy purposes (particularly farming and tourism)
- its cultural and environmental significance, including to Traditional Owners
- the size of properties (i.e. smaller lots increase transaction costs and social licence risk)
- population density and proximity of generation and/or transmission sites to residences and recreational infrastructure
- the existence of existing infrastructure (e.g., transmission lines and easements) which will lessen the visual and economic impact of new lines
- the timing and method of landowner and community engagement (i.e., early and open engagement lowers risk)

There are a range of options for integrating social licence considerations into the national transmission planning and infrastructure framework. At a high level, options include measures to quantitatively consider social licence in the ISP and measures to qualitatively embed social licence considerations. This section considers just the options for quantitative assessment.

Options to address this need
Options to integrating social licence considerations into the national transmission planning and infrastructure framework include:

- Sensitivity analysis: A quantitative assessment could be undertaken by AEMO for the ISP via sensitivities on technology build costs for generation, storage and transmission infrastructure, with the resulting ODPs compared against the 'base case' ODP to assess the importance of social licence. Under the current Rules, the ISP must "describe how each development path performs under any sensitivities AEMO considers reasonable"[56]. AEMO has flexibility to define sensitivities[57] and a social licence sensitivity can be included via noting it as a recommended sensitivity in the Cost Benefit Analysis Guidelines, and/or via an amendment to the NER[58]. Social licence sensitivities would draw attention to the issues of social licence and will be considered by AEMO when considering shortlisted credible development paths.

[55] Star of the South, Submission to the AEMO Draft 2022 ISP, 11 February 2022.
[56] NER 5.22.6(a)(3)
[57] The AER Cost Benefit Analysis Guidelines note "AEMO has flexibility over how it undertakes sensitivity testing and how many sensitivities to test" – p33.
[58] NER 5.22.6

For example, the following sensitivities could be developed to incorporate the impact of social licence considerations: sensitivities based on increased transmission costs (for example, 50% or 100% increase) to reflect the additional hurdles that obtaining a social licence to operate will entail – in particular the risk that some lines will need to be placed underground; or sensitivities based on increased generation LCOE (for example, 15% or 30% increase) to reflect the additional costs of developing in particularly remote areas.

    - Key advantages: This approach would result in the costs of meeting community requirements being considered in AEMO's selection of a development path; builds greater visibility and awareness of the potential costs of building and retaining the social licence to operate; does not directly inflate costs for consumers to meet anticipated costs of social licence.
    - Key disadvantages: This approach would not necessarily have a direct impact on ISP outputs; it would not affect the cost-benefit approach in the RIT-T; social licence is a very localised matter and modelling is unlikely to capture the regional specificities accurately.
    - Alignment with objectives: This approach may support timely delivery of critical infrastructure if the sensitivities influence the final optimal development path selection to be one which is less likely to face social licence challenges (which risk causing delays). If implemented via amendment of the Cost Benefit Analysis Guidelines, rather than the NER, limited reforms will be required.

- Reduced community impact option in RIT-T: A requirement could be introduced that TNSPs include a credible option for assessment in the RIT-T which would meet the identified need and also have a lower impact on communities, to the benefit of social licence for the project. For example, an option which includes segments of the network asset developed underground or replaced by non-network alternatives. Opportunities could be considered to elevate the project in the RIT-T evaluation – for example, if the low community impact option is found to deliver a net market benefit, it could be pursued even if not the option with the highest net market benefit.
    - Key advantages: This approach, depending on the details of implementation, could see a greater focus on what is required in infrastructure design to reduce community impacts, and how this translates to quantifiable costs and benefits, serving a communications and awareness purpose; it would open the door for a less impactful project to be delivered over one which would be lower cost but with a greater impact.
    - Key disadvantages: This approach is inconsistent with seeking a streamlined approach, and may increase RIT-T timeframes without achieving a different outcome; it may serve to highlight the magnitude of the cost difference to deliver a lower impact option, reducing support for social licence building initiatives; this approach could enable a project which does not deliver the best consumer outcome.

- Alignment with objectives: This approach is potentially consistent with the objective to support timely deliver of critical infrastructure, given that the selection of a lower impact project may ultimately reduce delays to getting the project developed, however it may increase timeframes for the RIT-T. It is inconsistent with safeguarding cost-efficient network investment outcomes, given it would enable approval of a project which is not the most cost efficient.

Preferred approach
In Baringa's view, requiring that AEMO develop a social licence-related sensitivity in its ISP is a sensible and practical means to introduce a quantitative assessment of social licence in the national planning and economic framework. Developing a methodology for assessing and costing social licence in the market, to develop this sensitivity, could be a useful foundation for any future measures which are introduced. In line with the objective to require limited reforms, this could initially be recommended in the AER's Cost Benefit Analysis Guidelines rather than in the Rules.

In terms of requiring that social licence issues are considered in RIT-Ts for actionable ISP projects, the opportunity for earlier and more material jurisdictional input – see Section 4.3.2 below – is preferred over the inclusion of a single reduced community impact option in the RIT-T. This option provides an opportunity for (potentially higher cost) low community impact options to be considered for those projects for which low community impact is identified as a priority.

4.3.2 Earlier and more material jurisdictional input

Why a policy revision may be needed
While the focus of transmission planning and investment review and reform processes (including the AEMC's current review) has been on the national economic framework, broader issues such as social licence and jurisdictional approvals processes can present significant challenges to projects and can introduce delays.

As jurisdictional governments have introduced their own community engagement and benefit sharing expectations, environmental commitments, and electricity sector priorities, the divergence between the jurisdictional expectations of a project and national expectations of a project has increased.

There is a risk of disconnect between projects which are approved in the national framework on the basis of maximising net economic benefits, and those which best meet the needs of the jurisdictions in which they are to be developed. The result is likely to be project delivery delays and potentially late-stage cost changes, as additional hurdles are encountered at the planning and environmental approvals stage.

Option to address this need, and preferred approach
One option to address this disconnect is to integrate jurisdictional needs alongside AEMO's identified needs for actionable ISP projects. This does not preclude additional opportunities to achieve earlier and more material jurisdictional input, however for the sake of brevity, and given the novel nature of this reform option, we focus our proceeding discussion on jurisdictional-identified needs.

The AER Cost Benefit Analysis Guideline states that, in describing an actionable ISP project, AEMO is required to:

- Assign one identified need to each actionable ISP project, <u>noting there can be multiple dimensions or components to a single identified need</u>; and

- Describe each identified need as the objective to be achieved by investing in the network. The description of an identified need must not mention or explain a particular method, mechanism or approach to achieving a desired outcome.

While it is important that AEMO's identified need description remains unchanged, reflecting the system needs and outcomes of their modelling, a jurisdictional component could be added as an additional dimension.

Jurisdictions could develop their 'needs' for each actionable ISP project following the publication of the draft ISP, with reference to their own planning, environmental, community and other requirements for the area in which the project is proposed. The jurisdiction may choose to consult with community and stakeholders in doing so. If it chooses to identify a need, this could be provided to AEMO in advance of the final ISP publication for inclusion in the document (but not to be incorporated into AEMO's modelling or analysis).

Examples of jurisdictional-identified needs include requiring:

- infrastructure build to not go within a certain number of kilometres of regional towns
- infrastructure not being built on particular types of agricultural land
- a particular community engagement or benefit-sharing approach will be adopted, and/or
- the (non-)network solution is resilient to physical climate change risks with 2°C assumption.

Key advantages of this approach include:

- All credible options considered in a RIT-T would need to be options which are capable of both meeting AEMOs component of the identified need as well as that of the jurisdiction, improving the likelihood that the preferred option will be one which will pass more efficiently through jurisdictional approvals
- Jurisdictions with environmental or other requirements could have these incorporated into projects without these requirements needing to be included in a quantified benefits assessment or the NEO; and
- Jurisdictional governments will be involved in projects earlier, and some preparatory activities will have commenced through this process.

Key risks and challenges to this approach, which would need to be carefully considered and worked through:

- Jurisdictions may introduce needs/requirements without adequate understanding of the costs involved, resulting in a significant increase in project costs. This could then increase the risk the preferred option no longer remains on the ODP following AEMO's feedback loop, risking the development of the project at all; and
- The AER will find it more challenging to assess whether an option identified in a RIT-T meets the identified need, if the jurisdictional component is more qualitative.

Alignment of this option with objectives:

- This approach aligns with the objective to support timely delivery of critical infrastructure, as jurisdictions would have the opportunity to identify needs which align with their planning approvals process, including environmental approvals and community engagement, reducing delays when those approvals arise.
- This approach may also align with enabling delivery of a 2°C warming future, if this is a jurisdictional position which has not been embedded into the ISP (for example, if not sufficiently 'committed').
- Implementation of this approach would require reforms to the NER, and does not closely align with the objective to require limited reforms. It would also require jurisdictions to develop processes or methodologies to arrive at their identified need.

An alternative, potentially complementary, option would be for jurisdictions to more clearly define specific community impact reduction requirements as part of their planning approvals framework. This would enable TNSPs to factor in the cost of meeting these jurisdictional requirements into their revenue determinations, consistent with the approach to environmental offsets and other jurisdictional requirements. However, this approach would not require jurisdictions to be engaged in projects and the community engagement process early.

4.4 Responsibility for projects

The scale of new transmission investment required in the NEM over the coming decades, to deliver the energy transition and a Net Zero-compatible electricity sector, has brought into question the allocation of responsibilities, costs and risks in the current framework.

In all NEM regions other than Victoria, responsibility for planning, developing, owning, operating and maintaining the network has traditionally been with incumbent, monopoly, transmission network service providers[59]. This shifted in recent years with the introduction of AEMO's role as network planner with development of the ISP. However, with the scale of new investment needed, and the need to have some of the new infrastructure built in very specific timeframes, has raised questions around whether this monopoly arrangement is fit-for-purpose.

Responsibility for funding the network infrastructure, and bearing the risks associated with funding the assets, has traditionally been entirely with consumers. Given the billions of dollars of investment in shared transmission infrastructure foreshadowed in the ISP, questions around the appropriateness of this cost and risk sharing model have also arisen. In particular, the question of whether generation and storage connected to the network should contribute to the costs of shared network, as is being considered in NSW.

4.4.1 Network service provider responsibilities

Why a policy revision may be needed

As noted above, the right to design, develop, operate, maintain and own large transmission projects has traditionally sat with the incumbent TNSP in the relevant region or, for interconnectors, regions. As has recently been highlighted, incumbent TNSPs have the exclusive right to these responsibilities

[59] Noting that this is not the case in NSW going forward, as it has introduced a contestability framework.

but not an obligation to take them on.[60] The decision to pursue a project largely remains a commercial decision in the hands of the individual service provider.

There are growing concerns these existing monopoly entitlement (but not obligation) arrangements are not suitable to deliver a network for Net Zero in the timeframes required and at least cost to consumers. In particular, the existing arrangements pose the following risks:

- An incumbent TNSP may choose not to develop a project which is needed in their region, when it is needed, in line with system requirements. A corporate decision to delay or turn-down a network project could have significant effects on investment in the market and achieving Net Zero. This potential risk was brought to the fore with the lodgement of rule change requests by TransGrid and ElectraNet concerning whether large projects were financeable under the current national framework[61].
- An incumbent TNSP may not be delivering the most cost-efficient solution for consumers. The rigorous assessment process, incentive schemes and consultation processes have been designed to reduce this risk, however the costs of large and unprecedented projects will inevitably be harder to assess and the risk of inefficient and uncontested project costs being proposed remains of concern.

It is important to note the arrangements are different in Victoria, where the transmission solution is centrally designed and then remaining responsibilities are contestably allocated to a single project proponent. Under the NSW Electricity Infrastructure Roadmap, new arrangements are also being introduced in NSW which will likewise see contestability introduced for some transmission project responsibilities (noting the final allocation between successful tenderer and incumbent TNSP is yet to be published).

The national framework also sees responsibilities allocated differently for transmission projects which are not directly consumer-funded, such as unregulated interconnectors or designated connection assets.

Options to address this need
There are a number of different approaches which could be taken to revise the allocation of network service provider responsibilities under the national framework:

- Retain status quo: The existing approach with incumbent TNSPs retaining the right but not the obligation to pursue projects could be retained. This may be justifiable on the assumption that the myriad of recent reforms and the growing threat of contestability itself may reduce the practical risk of incumbent TNSPs not pursuing the projects as required.
    - Key advantages: This approach has the benefit of being simple, requiring no reforms, and will give the recent reforms as well as the context of contestability reviews and introduction in NSW a chance to play out.

[60] While TNSPs have system security and reliability obligations to meet, they are not obligated to fund specific projects, especially ISP-identified projects, in order to comply with these obligations.
[61] Rule change requests lodged by TransGrid on 1 October 2020, and by ElectraNet on 23 October 2020. Information available here: https://www.aemc.gov.au/rule-changes/participant-derogation-financeability-isp-projects-transgrid#:~:text=On%2023%20October%202020%2C%20the,(PEC)%20with%20TransGrid).

- Key disadvantages: This approach ultimately does still retain a risk that the project is not pursued in the timeframes required for commercial reasons.
- Alignment with objectives: This approach best aligns with the objective to require limited reforms to implement, and may also result in positive outcomes in terms of the timeliness and cost-efficiency objectives given the incumbent TNSPs have a natural competitive advantage relative to if a new provider came in.

- Introduce an obligation to build projects identified by AEMO: An obligation to build could be introduced into the NER alongside existing obligations[62]. For example, TNSPs are already required to arrange for operation of the network over which they have control in accordance with instructions given by AEMO[63], and a similar clause could be inserted to require development of a network asset as instructed by AEMO.
    - Key advantages: This approach would provide certainty that necessary network assets will be developed when and where needed, without risk of TNSP commercial decisions leading to delays.
    - Key disadvantages: It will also be important to assess whether the introduction of an obligation is a proportionate response based on the practical risk of projects not being developed by incumbent TNSPs across the NEM.
    - Alignment with objectives: This approach would align with the objective to support timely delivery of critical infrastructure but would be expected to conflict with the objective of delivering cost-efficient network investment outcomes. The risks borne by the TNSPs in this option are likely to lead to risk premiums on investment and higher overall costs.

- Contestability: This approach is considered separately in section 4.4.2 below, given the substantive issues discussed within this topic.

Preferred approach
Of the two options considered here – noting the contestability option will be examined in the next section – the retention of status quo arrangements is the most realistic approach. It may be that some additional measures, such as amendments to existing arrangements to address financeability concerns, could be of benefit to providing more confidence that the current framework is sufficient for incumbent TNSPs to invest when and where needed.

If an obligation to build is introduced into the Rules, Baringa recommends the obligation should be built in as a backstop measure to be used in limited circumstances, rather than enabling AEMO to exercise the obligation at its discretion.

4.4.2 Contestability

Existing framework
Contestability in network service provision can occur in one of two ways:

1. Contestability within the monopoly TNSP-owned framework: contestability here relates to the incentive on TNSPs to seek out the most cost-effective means by which to procure

62 NER 5.2.3
63 NER 5.2.3 (e)

network services, and is a key part of the existing economic regulatory framework via incentive schemes such as the Efficiency Benefit Sharing Scheme (EBSS), for realising operational expenditure efficiencies, and Capital Expenditure Sharing Scheme (CESS) for achieving capital expenditure efficiencies.[64] The most cost-effective option may be for a third-party provider of the network service, OPEX or CAPEX, rather than the TNSP, though the TNSP would remain the procurer of that network service (in the case of CAPEX, the owner of the associated network infrastructure).

2. Contestability outside the monopoly TNSP-owned framework: this would enable the network service to be provided and procured by a business that is not necessarily an economically-regulated TNSP. In the case of CAPEX, a third-party would own and operate the associated network infrastructure.

Our discussion below is confined to 2., as we consider the existing regulatory framework provides sufficient incentives for TNSPs to consider contestable (i.e., non-TNSP-provided) providers of network services.

Why policy revisions may be needed
As noted above, the national framework does not currently support a competitive process for the delivery of transmission network projects. Incumbent TNSPs in each region are the assumed proponents of regulated network assets, and hold responsibility for design, development, ownership, operation and maintenance of the project.

Transmission in Victoria and NSW have their own state-specific contestable processes for network service provision (noting the exact responsibilities are yet to be published), and the AEMC is consulting on the merits of contestability in the national framework, through the Transmission Planning and Investment Review.

There are potential benefits to introducing contestability to large, discrete, transmission projects in the NEM, including:

- competition for these projects may result in reduced costs and greater innovation. This includes innovation on the project design, as well as innovation in cost-risk sharing approaches and other elements of operating and financing the project, if included in the contestable scope;
- the cost-savings which could be realised on large projects could exceed, and justify, the administration costs;
- competition would resolve the challenge of incumbent TNSPs currently having the exclusive right to develop a project but no obligation to do so;
- contestability would mitigate the financeability concerns of some incumbent TNSPs, by allowing tenderers to submit bids which they consider financeable; and

[64] For more on the CESS and EBSS, see AER, *Better Regulation: Expenditure Incentives*, Information sheet, November 2013, https://www.aer.gov.au/system/files/AER%20Better%20Regulation%20factsheet%20-%20expenditure%20incentives%20-%20November%202013.pdf

- given the costs of these projects are much harder for the AER to benchmark and assess, a contestable model may be a more appropriate and accurate means to arrive at an efficient project cost.

Some of these benefits are already leveraged. Under current arrangements, a significant component of the total costs for major transmission projects is typically procured by the TNSP through competitive processes after the revenue determination is complete. For example, TransGrid has identified that approximately 80% of the total costs of Project EnergyConnect has been procured competitively, including the construction, equipment and materials costs. Nonetheless, contestability may leverage cost savings in the design, delivery and operation of projects.

While the potential benefits are compelling, introducing contestability into the national framework will be a significant undertaking. To level the playing field between existing incumbents and prospective tenderers will require a thorough review and revision of the rules as well as an equivalent undertaking in each jurisdiction, where planning regulations and other processes will likely require revisions to remove the embedded rights of the incumbent TNSP.

Introducing contestability into the national framework is also unlikely to have NEM-wide uptake for intra-regional projects in the near-term. It is important to consider the current status of networks and network development across the NEM:

- Victoria already has a state-specific contestable development model for transmission projects;
- NSW has now developed its own state-specific contestable development model for transmission projects, to deliver its Roadmap; and
- Tasmania and QLD both have state-owned network businesses, and are likely to be conflicted in any decision to adopt contestability nationally given the revenue implications.

These jurisdictional policies and positions are likely to take precedent over application of a national contestable approach for the development of intra-regional projects over at least the coming decade. Any national approach to contestability should seek to align with the Victorian and NSW frameworks as much as possible to reduce the burden of harmonisation in the future.

Options to address this need
There are a number of options for the introduction of contestability into the national framework. This is a very complex issue, and one which we have not covered in detail in this paper. Instead, we have identified the high-level options and some of the key benefits and limitations of each.

- Full contestability: This approach would see a new contestability framework introduced, where projects identified by AEMO in the ISP, as the central plan, could be subject to a contestable process to allocate NSP responsibilities. This would span design, development, ownership, operations and maintenance.
    - Key advantages: This approach would have the potential to deliver the cost and time savings, and the innovation, which is often assumed to arise from competitive processes. Cost savings could accrue from both lower CAPEX and a lower cost of capital than a TNSP-by-default approach, with a lower cost of capital arising for those unregulated entities with stronger credit rating than incumbent TNSPs.

- Key disadvantages: The interface between the incumbent TNSP and the NSP responsible for a new network asset will be challenging to navigate – particularly from a network operations and maintenance perspective. This challenge will be reduced if contestability is limited to discrete and separable projects. This approach will require considerable new policy development, new processes, roles and responsibilities, and a lot of administration. Given so much of a total project value of existing projects is already delivered through competitive processes, it us unclear whether there is a net benefit to contestability.
- Alignment with objectives: This approach would align with the objectives concerning timeliness of critical projects, and delivering cost-efficient network investment. However, it does not align with the objective to require limited reforms.

- Contestability of design, delivery and ownership: As a partial contestability approach, it may be possible to introduce contestability just for the initial design, development and ownership of a project. This would mean the operations and maintenance remain the responsibility of the incumbent TNSP.
  - Key advantages: This approach would potentially deliver some time and cost savings through competition, but would avoid some of the practical challenges of removing operation and maintenance responsibilities from the incumbent TNSP for just a discrete section of the network. The administration and regulation of this approach would be slightly reduced relative to full contestability due to not needing to resolve some of these operational issues.
  - Key disadvantages: New challenges may be introduced if the incumbent TNSP is responsible for operating and maintaining a network which it didn’t own and doesn’t have responsibility for developing. Given so much of these responsibilities are already subject to a competitive process, the value-add may not be significant.
  - Alignment with objectives: As above, this approach would align with the objectives concerning timeliness of critical projects, and delivering cost-efficient network investment. However, it does not align with the objective to require limited reforms.

- Contestability of interconnectors only: The application of a contestable framework for interconnectors could be considered as an alternative to the current regulated and merchant approaches. This is particularly relevant given the shortcomings in the current unregulated interconnector development approach[65] and the challenges recently demonstrated in progressing Project EnergyConnect, a regulated interconnector, in a timely manner. It is not clear that interconnectors could be developed under the jurisdiction-specific reforms applied in some regions, so a national contestable framework would likely be applied if introduced.
  - Key advantages: This approach would offer the significant benefit of enabling a regulated interconnector to have a single proponent, rather than being developed jointly by two TNSPs. This would simplify the design and cost-benefit assessment process, as well as the actual project build-out.

[65] Two of the three MNSP-developed interconnectors in the NEM have been converted to regulated assets, and the third – Basslink – has recently gone into administration. No additional interconnectors have been proposed to be built under the MNSP regime.

    - Key disadvantages: This approach would require significant policy development and new processes, roles and responsibilities, which might not be proportionate to the benefits delivered, given the rarity of interconnector projects.

- Alignment with objectives: As above, this approach would align with the objectives concerning timeliness of critical projects, and delivering cost-efficient network investment, relative to the interconnector development framework currently in place. However, it does not align with the objective to require limited reforms.

Preferred approach
Contestability would be a longer-term reform option and is not an option which could deliver benefits to projects in the near-term.

Consideration of contestability as a long-term reform option should be informed by detailed cost-benefit analysis to determine whether the potential benefits would justify the significant policy reform process required to introduce it. Baringa is of the view that contestability is particularly worth considering in the national framework for the development of interconnectors. The case for introducing contestability into the national framework more broadly, for intraregional projects, appears to be less clear.

If a national contestable framework for large transmission projects is considered, efforts should be made to align with state processes, where possible, so that NSW and VIC would be more likely to transition to the national approach in the long-term.

4.4.3 Cost and risk sharing arrangements

As noted above, responsibility for the costs and the risks of the network development has traditionally sat with electricity consumers. Once forecast costs for a new project are approved, the TNSP is entitled to recover the costs from consumers, via electricity bills, over a number of decades. If the network is underutilised and not delivering the benefits anticipated, consumers will still generally continue to pay the costs, meaning consumers bear this risk. This arrangement has been justified on the understanding that the network is developed to meet consumer needs, and that consumers are the primary beneficiaries.

There has been debate for a number of years now around whether the cost and risk sharing arrangements need to be revised. In particular, whether the development of network infrastructure is actually benefiting, not only consumers, but also connecting projects and potentially governments as well. The question of appropriate risk and cost sharing is particularly pertinent in the context of the ISP, in which billions of dollars of new investment will be required.

This question has also been brought to the fore through the recent consideration of network access schemes by State Governments and energy market bodies. The potential for generators to contribute to network costs is inherently linked to access. The open access regime currently provides no incentive for generators to contribute to costs, given they are not guaranteed any level of access to the network and given the risk of other projects ‘free riding’ off this investment and diminishing the benefits for the funding project. Introducing a generator contribution to network infrastructure costs will require commensurate improvements in access conditions or the introduction of other new arrangements which create value for those who contribute to network costs.

The CEIG has recently published a proposed new approach to access arrangements for the NEM, which included alternative cost and risk sharing arrangements[66]. The proposal, developed by Castalia, included the potential for connecting projects to contribute to the costs of some shared network infrastructure with the majority of the costs continuing to be recovered by consumers. This was proposed to be the case for network infrastructure for which the capacity of projects seeking to connect at a point in time exceeds the transmission hosting capacity, and access fees are introduced as part of the competitive access allocation process. Castalia and in turn the CEIG also proposed projects could pay Transmission Charges to enable generator-funded network augmentations, allowing them to connect where there is otherwise insufficient network headroom.

The generator-contribution model, in which access fees may be used to contribute to – but not cover the full costs of – shared network assets, has also been proposed by the NSW Government to apply in its CWO REZ access scheme[67].

Baringa's report will not critique the option published by CEIG, as developed by Castalia. Instead, we discuss below the third option for network cost and risk sharing, which is for governments to contribute to costs and/or bear risks of network infrastructure development.

Options to address this need, and preferred approach

As noted above, this section will not reconsider the potential for generator contributions to network infrastructure costs, as this has recently been considered by the CEIG. Instead, we have considered the advantages and disadvantages of government bearing some cost and risk alongside consumers and potentially generators.

State and/or Federal Government(s) could contribute to the costs of new network assets in the NEM, particularly where the development of specific infrastructure in specific timeframes is important to the government meeting their own objectives. While this may not have been a relevant consideration in the past, the notion of governments benefiting from the development of network infrastructure is now relevant as State Governments commit to renewable energy development and all governments commit to Net Zero by 2050. For example, NSW Government has legislated targets for specific capacities of new generation to be built by 2030[68], and the development of new network infrastructure is critical to the government meeting these targets. The Victorian Government has recently committed to offshore wind targets[69], and for the government to meet these targets will likewise require new transmission infrastructure to be funded and built in the timeframes necessitated by these targets.

---

66 CEIG, 2022, *Rethink of Open Access Regime*, Report developed by Castalia. https://ceig.org.au/wp-content/uploads/2022/02/2022-02-23-Report-on-Transmission-Access-Reform.pdf

67 NSW Government, 2021, REZ Access Rights and Scheme Design consultation paper, https://www.energy.nsw.gov.au/sites/default/files/2021-12/rez-access-rights-and-scheme-design-central-west-orana.pdf

68 NSW Government, Electricity Infrastructure Investment Bill 2020, 44(3)

69 VIC Government, 2022, Offshore Wind Policy Directions Paper, https://www.energy.vic.gov.au/__data/assets/pdf_file/0016/561400/Offshore-Wind-Policy-Directions-Paper.pdf

Government funding is uniquely able to reduce the market costs of a project when assessed in the RIT-T, improving its cost-benefit outcome. Government funding could therefore be considered as a means to ensure particular projects are delivered in a timely manner, which may otherwise fail to eventuate (either at all or in a timely manner) as preferred options in the RIT-T, such as projects which meet particular social licence objectives, which are particularly anticipatory, or which are being delivered early relative to national planning. In this way, government funding can act as a means to cover the additional costs of delivering a project outside of the nature and timeframes deemed efficient through central planning, rather than consumers bearing this additional cost.

Key advantages of government funding of major network infrastructure projects include:

- the delivery of network infrastructure projects in a timely manner consistent with achieving Governments' emissions reduction commitments
- when the funding is needed earlier or of a different nature to those in the ISP, to meet government needs, is the protection of consumers from covering costs beyond those deemed optimal by AEMO
    - when the issue is one of *timing* rather than ultimately meeting a different need, then governments can provide liquidity that enables the development of network projects to proceed at-pace, with government funding then recovered from consumers once the economic consumer benefit test has been passed
- where market benefits of network projects accrue to customers beyond one NEM region, or in the case of interconnectors beyond two interconnected NEM regions, then a stalemate can occur where there are difficulties determining individual regions' share of the benefits and in turn the costs. This has been evident in the discussion over MarinusLink, the second VIC-Tasmania interconnector, where the system benefits accrue to more than just VIC and Tasmanian customers. Federal Government funding can then break this stalemate and solve the co-ordination problem, and
- unlike other funding options, government funding also sits easily within the existing national framework as a means of reducing the in-market costs of a project as assessed in a RIT-T, and this option would not require reforms to implement.

Key disadvantages of this approach include:

- Stranding asset risk and risk of cost overruns is shifted from electricity consumers to taxpayers
- Governments may be more motivated by non-economic considerations in relation to funding network infrastructure, though this need not be incompatible with – and indeed may be entirely consistent with – the jurisdictional-identified needs noted in section 4.3 in relation to incorporating community benefits and social licence considerations into network planning and investment decisions.

Preferred approach

Reflecting the reality that government funding of transmission network infrastructure has already occurred, is occurring, and is likely to continue to occur, by State and/or Federal Government(s), our preference is to provide governments with frameworks to assess when, how, and to what extent, government funding of network infrastructure should occur in the NEM. The *NSW Industry*

Development Framework[70], developed to guide NSW Government decision making on funding a range of investments, is a useful template by which to develop a NEM-wide framework.

Furthermore, contributions to the cost of network infrastructure should be retained as an option under the national framework as a means to progress projects which are earlier or of a different nature than those projects identified as optimal in the ISP (particularly when governments are seeking to meet their jurisdictional commitments). This role would be additional to the *liquidity* Governments can provide; namely, providing funding to progress network projects though the costs of these projects, including Government financing costs are, ultimately, recovered from consumers.

[70] See https://www.investment.nsw.gov.au/living-working-and-business/nsw-industry-development-framework/

5 Quantifying the impact of delaying transmission

5.1 Costs and benefits of additional transmission capacity

As discussed in section 1.1, increased transmission capacity is crucial for enabling the NEM to contribute to Australia's emissions reduction commitments, and in turn contribute to global efforts to limit global warming. New transmission capacity, both intra- and inter-regionally, is needed for two reasons:

1. To unlock the significant volumes of generation and storage capacity needed to replace ageing fossil-fuel generators. This is required even if demand is unchanged. The best locations for renewable resources in the NEM are typically distant from the existing transmission network and demand centres. Therefore, significant investment in Renewable Energy Zone (REZ) transmission capacity and related augmentations is required. The need for additional transmission capacity is heightened when achieving Net Zero is also accounted for (see next point).
2. To unlock new renewables generation and storage capacity to meet the significant increase in electricity demand from zero-emissions electrification of transport, residential heating and cooking, manufacturing, and heavy industry, within Australia and globally. Zero-emissions electrification of these sectors enables these sectors to contribute to the achievement of Net Zero electricity demand reflects the need to achieve Net Zero within Australia and globally.

Interconnector capacity is also a key driver for decarbonisation, as interconnectors help to manage and smooth supply-demand imbalances between NEM regions given the fluctuation in variable renewable energy generation within and between regions.

Transmission network investment in the NEM has both benefits and costs. We focus on benefits and costs to end-consumers, for which price changes are the best measure of consumer impact. Other studies focus exclusively on changes in *system costs*, which reveal the costs incurred in generating and transporting electricity.[71]

5.1.1 How extra transmission impacts consumers financially

A key metric to assess financial impact from extra transmission is electricity prices for end-consumers. All else equal, investing in additional transmission capacity is expected to:

- increase network prices; this may be tempered by electrification-driven increases in electricity demand, as the higher network cost is allocated over a larger consumer base, and

[71] Changes in prices vis-à-vis changes in system costs reveals the extent to which changes in system costs are allocated to consumers vs. generators. For example, if system costs rise but prices are unchanged, the increase in system costs are thus borne by generators – via lower revenues and profits – not consumers. However, the sustainability of this outcome is then in question: generator exit can occur sooner if their profits decline to unsustainably low levels. Subsequent generator exit can then lead to higher consumer prices, implying the rise in system costs are, ultimately, borne by consumers.

- yield lower wholesale prices from increased output from lower short-run marginal cost (SRMC) generation capacity and also from greater wholesale market competition (i.e., more competitive bidding behaviour).

However, these are not the only financial impacts on consumers. Extra transmission can also provide emissions reduction benefits from enabling more renewables into the system, which both displaces fossil-fuel generators and enables zero-emissions electrification in sectors such as transport, manufacturing, heavy industry (e.g., steelmaking, fertiliser production), and heating and cooling, which also displaces fossil fuels. By lowering the extent of global warming, extra transmission can provide consumers direct financial impacts from reduced frequency and severity of extreme weather events (e.g., bushfires, floods, and sea-level rise) by reducing the cost of mitigation and/or adaptation efforts (e.g., reducing the cost of property insurance).

Hence, our measure of consumer financial impact considers both electricity price changes and decarbonisation costs/benefits.

To date, and to the best of Baringa's knowledge, the bulk of cost-benefit analysis on the impact of transmission investment in the NEM, including notably the RIT-T, focus on benefits and costs *within the NEM*. However, for this study, we have also considered the **benefit of emissions reductions occurring outside the NEM due to electrification powered by electricity generators within the NEM and in turn enabled by additional transmission investment**.

As with other studies, we do not attempt to model the broader impacts of transmission investment in terms of impacts on employment and incomes.[72] This is a much more complex exercise as it needs to take account of the various channels through which transmission investment impacts the macroeconomy (including, for example, the impact on labour markets and on related goods and services). This exercise is beyond the scope of this report, and as such we briefly discuss the benefits of additional transmission investment by highlighting third-party analysis of the benefits of achieving Net Zero – which is broader than just transmission investment but gets at the key benefit of extra transmission: enabling Net Zero.

5.2 Modelled scenarios

Baringa has sought to quantify the costs associated with not achieving transmission build at the pace and scale required to align with achieving economy-wide Net-Zero-by-2050. For this quantification exercise, we construct the following two scenarios:

1. *On-time Transition*: a 2°C- aligned scenario that achieves economy-wide Net Zero CO_2-e emissions from 2050
2. *Delayed Transition*: a scenario where the timing of intra- and inter-regional transmission network augmentations required under *On-time Transition* is delayed by three years. All other inputs are as per *On-time Transition*.

[72] Examples of macroeconomic impacts from additional transmission include the negative impact on employment and incomes in fossil-fuel sectors (e.g., loss of jobs and incomes due to earlier closure of incumbent coal plants from being undercut by renewables). By the same token though, transmission investment can have macroeconomic benefits by boosting employment and incomes in sectors such as engineering and construction.

The inputs for each of these two scenarios have been determined by Baringa, based largely on AEMO data, supplemented with Baringa internal data, with *On-time Transition* largely aligned with AEMO's Draft 2022 ISP *Step Change*.[73] The inputs selected for each of *On-time Transition* and *Delayed Transition* are shown in Appendix A.

The *Delayed Transition* scenario is intended to model a pathway where transmission augmentation is not actioned quickly enough to keep pace with achieving AEMO's Draft 2022 ISP *Step Change* scenario[74]), resulting in deployment of renewables and zero-emissions firming capacity (i.e., pumped hydro and battery storage) that is inadequate for achieving economy-wide Net Zero by 2050. In Baringa's view, a 3-year timeframe reflects a reasonable estimate of the impact, in terms of delays to transmission build dates, of not implementing the policy recommendations noted in section 4.

We then compare the differences between the two scenarios in terms of:

- the impact on residential and small-medium enterprise (SME) electricity prices
- the composition of the capacity mix and composition of the associated generation mix
- the level of CO_2-e emissions across the NEM 'monetised' by the social cost of carbon, and
- the reduction in non-NEM emissions from electrification 'monetised' by the social cost of carbon – this includes (but is not limited to) green hydrogen production that replaces fossil fuels in industrial and transport sectors.

5.3 End-consumer impacts

5.3.1 Overall impacts (electricity bill changes + decarbonisation costs)

Delaying transmission buildout leads to increased costs to residential and SME customers in each and all of five NEM regions. Over the FY2022-FY2055 period, the largest cost to residential customers is in Victoria ($20 p.a., or $813 over the FY22-FY55 period, per customer), and the smallest cost in NSW ($13 p.a., or $417 over FY22-FY55, per customer) (Figure 4). The largest costs for SME customers are again seen in Victoria ($128 p.a., or 4,231 over FY22-FY55, per SME), and the lowest costs in SA ($51 p.a., or $1,668 over FY22-FY55, per SME) (Figure 5).

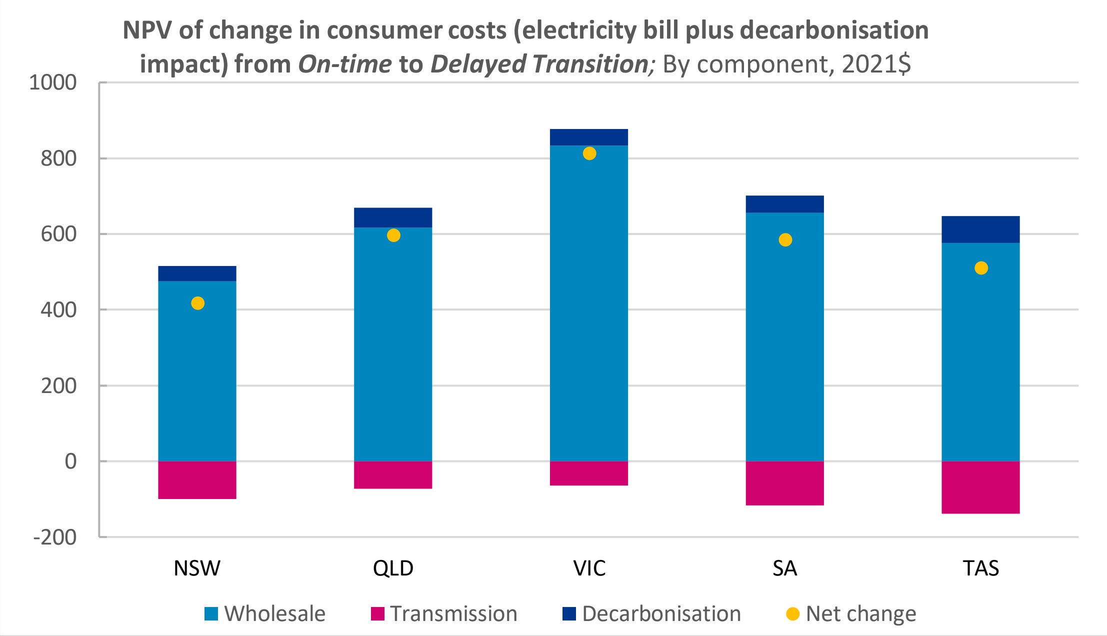
These costs exclude the costs of lower employment and incomes from delaying transmission investment.

These costs are driven primarily by the higher cost of wholesale electricity from delaying transmission investment, in turn delaying the deployment of zero-SRMC renewables. There is also a cost to consumers from lower decarbonisation, with economy-wide Net Zero not achieved by 2050 under *Delayed Transition*. The higher CO_2-e emissions under *Delayed Transition* are due to increased generation from fossil fuel-fired plant, with fossil fuel plants replacing renewables.

[73] *On-time Transition* is not perfectly aligned with *Step Change* because *On-time Transition* uses the ODP from AEMO's Draft 2022 ISP which is not exactly aligned with *Step Change* as the ODP's weighting on *Step Change* is not 100%, as discussed in section 3.1.1. Also, coal closures under *On-time Transition* are generally later and slower than for *Step Change*, especially during the 2020s, for reasons , discussed in Appendix A.

[74] As discussed in section 3.1.1, *Step Change* is aligned with limiting global warming to 1.8°C by 2100.

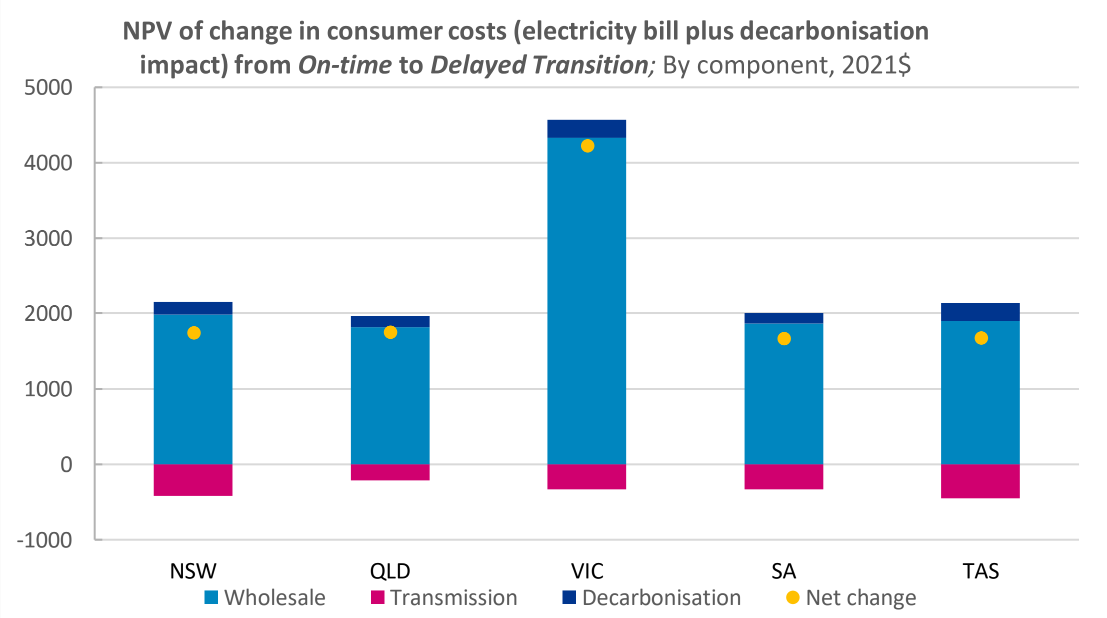
Figure 4: Costs to residential electricity customers from delaying achieving *On-time Transition*



Note: Positive (negative) amounts indicate increase (decrease) in costs when moving from *On-time Transition* to *Delayed Transition*. Average household consumption varies by NEM region, sourced from the AEMC's *2021 Residential Electricity Price Trends* report

Source: Baringa Partners LLP

Figure 5: Costs to SME electricity customers from delaying achieving *On-time Transition*



Note: Positive (negative) amounts indicate increase (decrease) in costs when moving from *On-time Transition* to *Delayed Transition*. Average SME consumer consumption varies by NEM region, sourced from the ECA's *2021 Small and Medium Enterprise (SME) Retail Tariff Tracker Project* report

Source: Baringa Partners LLP

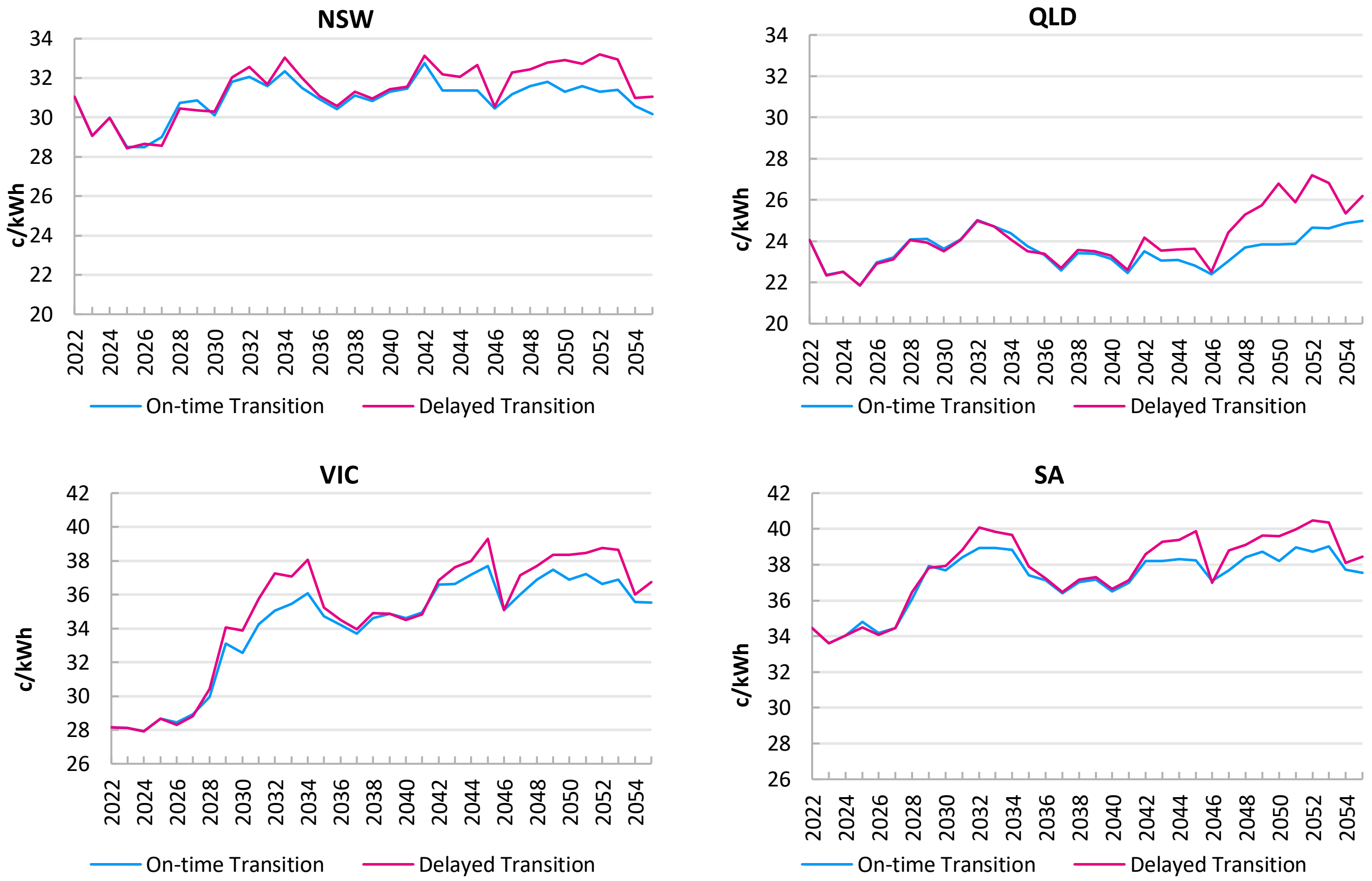
5.3.2 Consumer bill outcomes

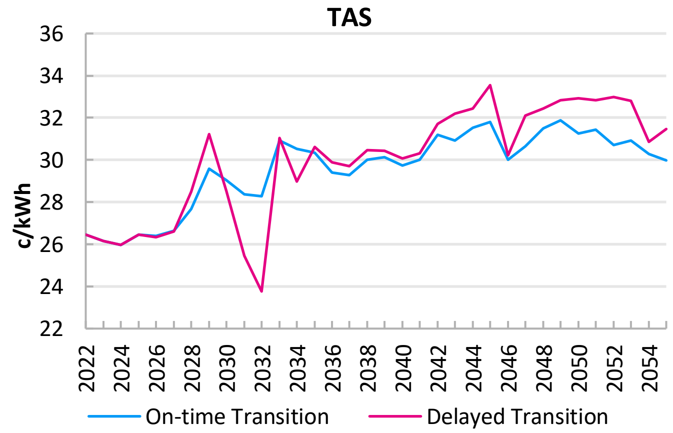
Focusing on electricity bill outcomes, Figure 6 and Figure 7 show residential and SME consumers' bills are higher under *Delayed Transition vs. On-time Transition*. This in turn reflects higher electricity prices under *Delayed Transition*, as residential and SME electricity consumption are both held constant (at their respective levels) across both scenarios. This electricity price increase is a function of:

1. Increased wholesale electricity costs due to delayed deployment of renewables and in turn increased output from incumbent coal- and especially gas-fired plant.
2. Slight reduction in transmission costs driven by a delay to investment in transmission augmentations.

Over the full horizon (FY2022 – FY2055), delayed transmission augmentations increase electricity prices. However, in some years and in some regions – for example, Tasmania in the early 2030s – delayed augmentations can *reduce* prices by increasing the extent of excess supply (i.e., excess generation capacity). However, this effect is transitory; delayed augmentations result in reduced economic new-build (i.e., uncommitted) renewables capacity, which then sees higher prices under *Delayed Transition* as there is less displacement of more expensive fossil fuel-fired plant. The impact on the capacity and generation mix from delayed network augmentations are further discussed in section 5.4.

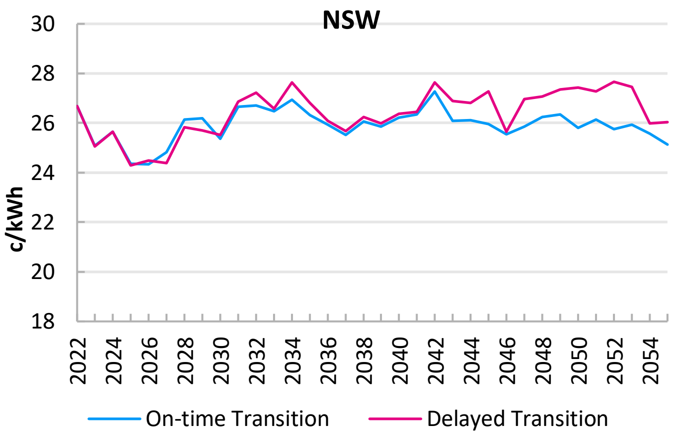
Figure 6: Residential electricity prices (2021$)

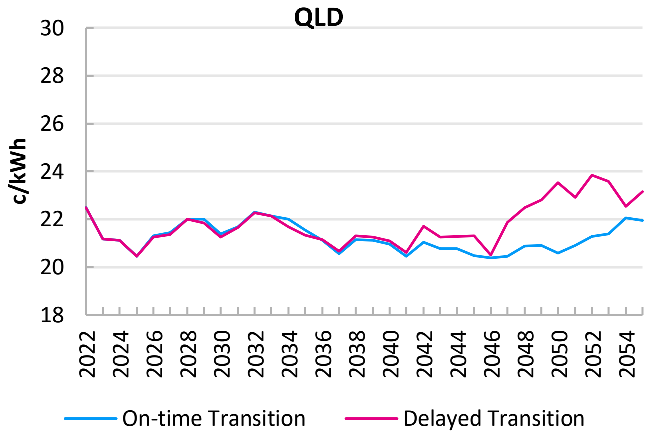


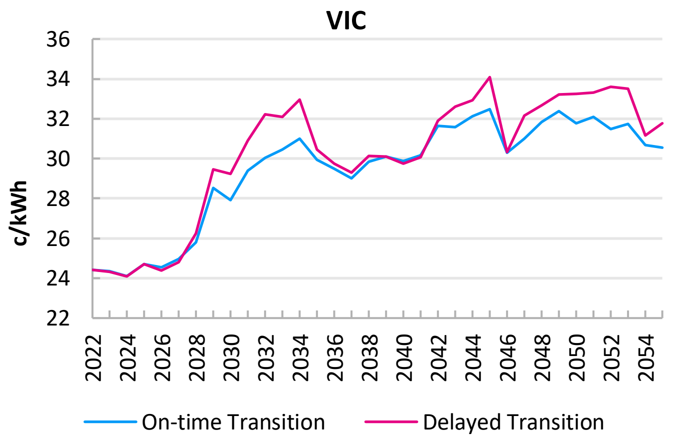


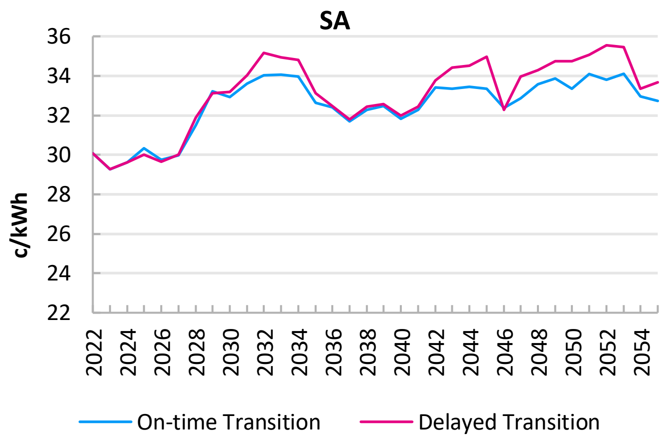
Note: Residential electricity prices for FY2022 are from the AEMC's *2021 Residential Electricity Price Trends* report
Source: Baringa Partners LLP

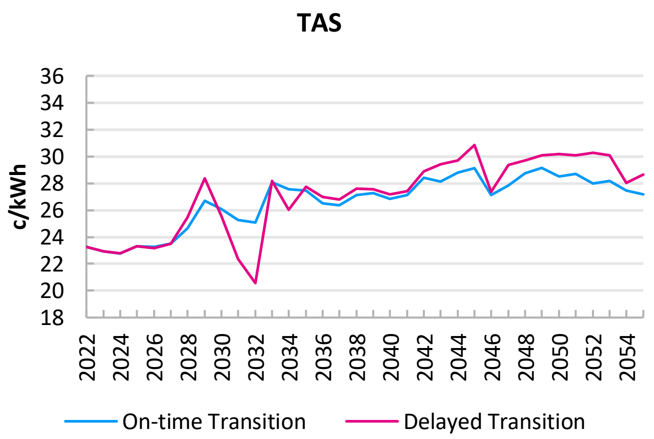
Figure 7: SME electricity prices (2021$)











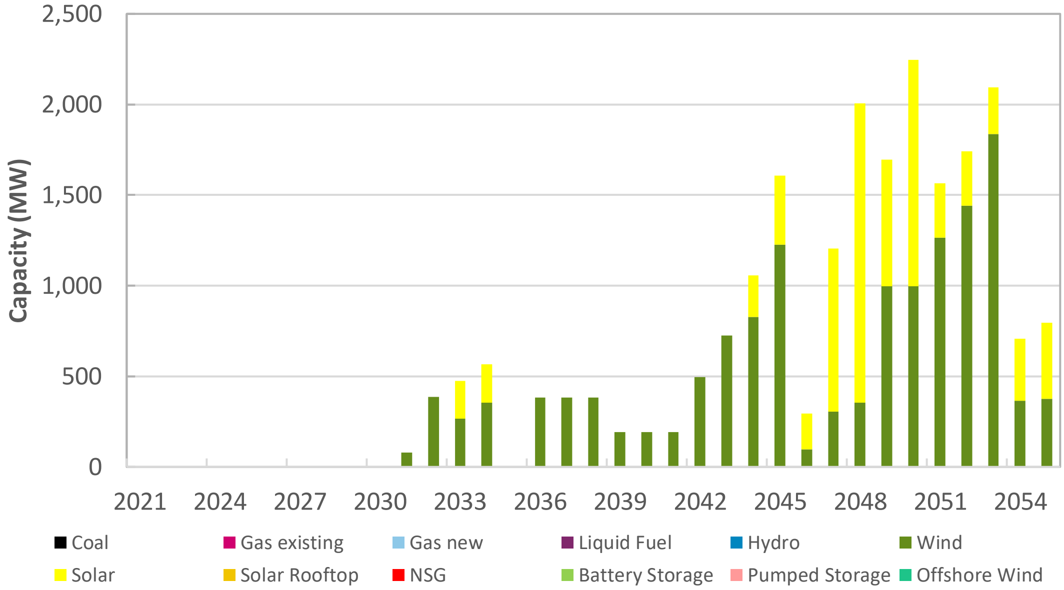
Note: SME electricity prices for FY2022 are taken from the ECA's *2021 SME Retail Tariff Tracker Project* report

Source: Baringa Partners LLP

5.4 Impact on the generation and capacity mix

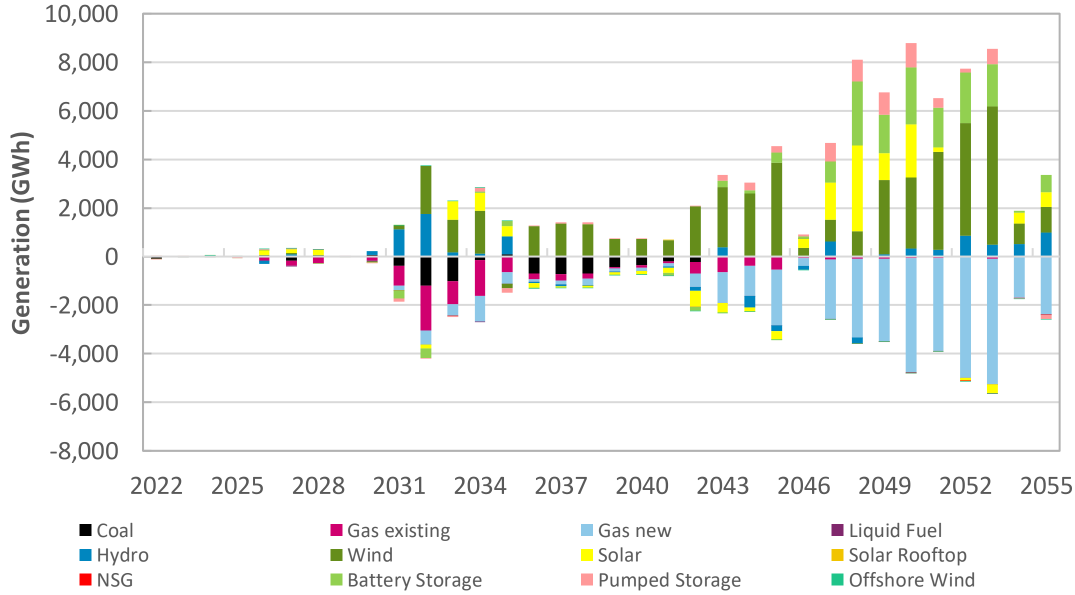
Under *Delayed Transition*, and relative to *On-time Transition*, the installed capacity of renewables is smaller due to the delayed augmentations to the transmission network (Figure 8). Under both scenarios, the fossil fuel-fired generation capacity remains unchanged.

Figure 8: Change in projected installed capacity, NEM-wide, *On-time* vs. *Delayed Transition**



* Positive (negative) values indicate installed capacity of that technology type is higher (lower) under *On-time Transition* compared to *Delayed Transition*, as at 30 June of that financial year
Source: Baringa Partners LLP

Figure 9: Change in projected generation mix, NEM-wide, *On-time* vs. *Delayed Transition**



* Positive (negative) values means output is higher (lower) under *On-time* vs. *Delayed Transition*, over that financial year.
Source: Baringa Partners LLP

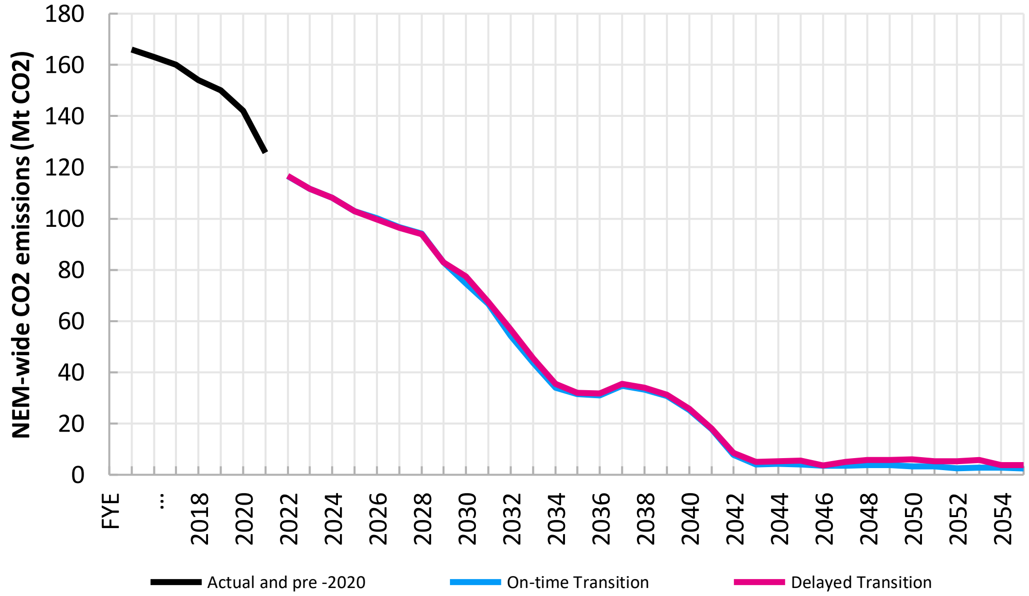
The changes in generation between *On-time Transition* and *Delayed Transition* reflect the corresponding changes in the renewables installed capacity. That is, the increase in renewables output under *On-time Transition* reflects the higher installed capacity of renewables (Figure 9). This then has emissions reduction benefits as discussed in the next section.

5.5 Impact on emissions

5.5.1 Emissions within the NEM

Delivering the transmission investment at the pace and scale required to achieve economy-wide Net Zero by 2050 sees lower NEM-wide CO_2-e emissions across the horizon, vs. *Delayed Transition* (Figure 10). This is because timely REZ augmentations under *On-time Transition* means earlier deployment of renewables, which then displaces thermal plant (coal, and in particular gas) generation.

Figure 10: NEM-wide CO_2-e emissions p.a., historical and projected



Source: Baringa Partners LLP

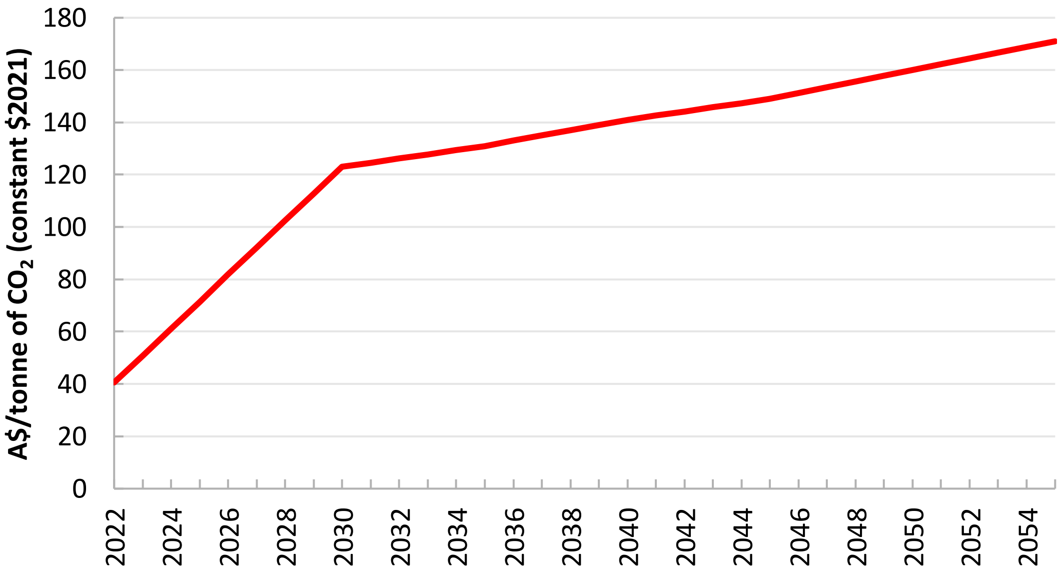
5.5.2 The value of emissions abatement

As mentioned in section 5.3, reducing emissions provides benefits to consumers, and society more generally, as abatement reduces the likelihood of physical climate risks being realised over time, which in turn reduces the damages associated with climate risks. Climate physical risks – such as extreme weather events and rising sea levels – can yield both benefits and costs, and the *social cost of carbon* (SCC) captures all the quantifiable costs and benefits of emitting one additional tonne of CO_2-e emitted, in monetary terms.

A positive (negative) value for the SCC indicates an additional tonne of CO_2 creates net costs (net benefits). Some consider the SCC to be positive (i.e., costs to exceed benefits for each additional tonne of CO_2-e emissions abated) above 1.1°C of warming.[75] A positive value for the SCC indicates that a tonne of avoided CO_2-e has a social benefit equal to that monetary amount.

To estimate the benefits associated with the greater decarbonisation achieved under *On-time Transition* vs. *Delayed Transition*, we apply the SCC value used by the ACT Government in its 2020-21 State budget, of $20/tonne of CO_2-e for 2022.[76] We then linearly interpolate between this value for FY2022 and the SCC value for FY2030 ($123/tonne), obtained from the advice to the ACT Government on the value of the SCC that should be used by the Government when undertaking a cost-benefit analysis of alternative policies and investments to achieve its emissions reduction targets.[77] We then apply the values from this advice to the ACT Government for the post-2030 period (Figure 11).

Figure 11: Social cost of CO_2-e emissions



Source: Baringa Partners LLP, based on SCC values obtained from public ACT Government data

Applying this to the emissions avoided within the NEM (Figure 10) under *On-time Transition* relative to *Delayed Transition* yields benefits to Australian consumers, and society overall, of up to $486 million in FY2053, and a total of $5.4 billion from FY2022 to FY2055.

5.6 Macroeconomic impacts

A discussion of the benefits of extra transmission capacity would be incomplete without also discussing the macroeconomic benefits of extra transmission. As previously mentioned, extra

[75] https://www.carbonbrief.org/in-conversation-roger-harrabin-and-richard-tol

[76] https://www.cmtedd.act.gov.au/open_government/inform/act_government_media_releases/rattenbury/2021/considering-the-social-cost-of-carbon

[77] The ACT Government's emissions target is to achieve Net Zero CO_2-e emissions by 2045 – as part of overall efforts to limit global warming to 2°C or below, with interim targets including a 50–60% reduction (below 1990 levels) by 2025. The SCC value for FY55 in Figure 11 is based on a 2.5% p.a. discount rate, to convert future year SCC values to present-day values. For more details, see N. Hutley, *A Social Cost of Carbon for the ACT*, DRAFT Prepared for the ACT Government, March 2021

transmission is a key enabler for a renewables-led electrification of the economy and in turn a key enabler of Australia achieving Net Zero and contributing to global efforts to limit warming.

It is beyond the scope of our report to fully analyse the macroeconomic benefits of extra transmission, as such analyses would need to consider benefits (in terms of extra employment and incomes in those industries benefitting from electrification) and costs (lost jobs and lower incomes in those industries negatively impacted from electrification). Instead, we draw on the following two recent studies that have examined the benefits and costs of electrification for the Australian economy, and by extension the benefits and costs of extra network capacity:

1. Australian Government modelling of benefits and costs of achieving Net Zero[78], and
2. Business Council of Australia (BCA) modelling of Net Zero.[79]

5.6.1 Australian Government Net Zero modelling

This study makes the important observation that achieving Net Zero avoids the carbon risk premium imposed on Australia's cost of capital, additional to the benefits, discussed in section 5.5, from avoiding damages from realisation of physical climate risks (embodied in the SCC). Moreover, there are additional benefits to Australia from developing an export-focused green H_2 sector, which is a key part of a broader electrification theme which in turn relies on more transmission investment.

The analysis finds the combination of a lower cost of capital and electrification boosts national income by 1.6% in 2050, relative to no-action, equivalent to an additional $2,000 per person (or a c.10% increase in average incomes per capita) in today's dollars.

5.6.2 BCA Net Zero modelling

This study found that a coordinated transition to Net Zero by 2050 for Australia would result in a $890 billion increase to GDP, each Australian being around $5,000 better off in 2050 relative to the status quo, with regional Australians around three times better off compared to capital city residents.

In the context of increased transmission capacity, it is useful to distinguish between the impact on regions and regional residents, vs. capital cities and capital city residents. Through effective stakeholder engagement that obtains social licence for new transmission and generation infrastructure, the benefits from increased transmission can have an especially large beneficial impact on regional areas in terms of employment and incomes. We discussed social licence issues in section 4.3, where we noted that community support is vital to the timely progress and delivery of both near-term priority and future transmission projects.

---

78 Australian Government, *Australia's long-term emissions reduction plan: Modelling and analysis*, October 2021
79 Business Council of Australia, *Achieving a On-time Transition economy*, October 2021

Appendix A: Baringa's market modelling

A.1 Summary of input assumptions

The key input assumptions are summarised in Table 4. The key difference in input assumptions between the two scenarios relate to the 3-year delay to inter- and intra-regional transmission network commissioning under *Delayed Transition* vis-à-vis *On-time Transition*.

Note our approach to closing coal and gas plants generally results in closure under *On-time Transition* (and therefore also under *Delayed Transition*) that is later than the corresponding closure dates from 2022 Draft ISP *Step Change*. This is especially for coal closures that occur under *Step Change* during the 2020s. In Baringa's view, and based on market liaison, the pace and scale of coal closures under *Step Change* during the 2020s is a case of "too fast, too soon". This reflects the following considerations:

- 2022 Draft ISP *Step Change* closes coal based on emissions intensities – higher emissions-intensive plants are closed sooner than less emissions-intensive ones – which is akin to a closure approach based on the existence of a carbon price. Yet, various governments – at both State and Federal level – have explicitly ruled out placing an explicit price on carbon
- The recent experience with the Yallourn plant in VIC suggests the VIC Government is reluctant to close that plant sooner than 2028.[80] Such reluctance may also extend to closing over VIC plants during the 2020s
- Similarly, public statements by the QLD Government[81] on its 10-year energy transition plan – which seeks to lay out how the State will reach its 50 per cent renewable energy target by 2030, cut carbon emissions by 30 per cent by 2030, and achieve economy-wide Net Zero by 2050 – has ruled out any of the State's eight coal-fired power stations being closed early as a means to achieve the climate change and energy targets within the 10-year plan

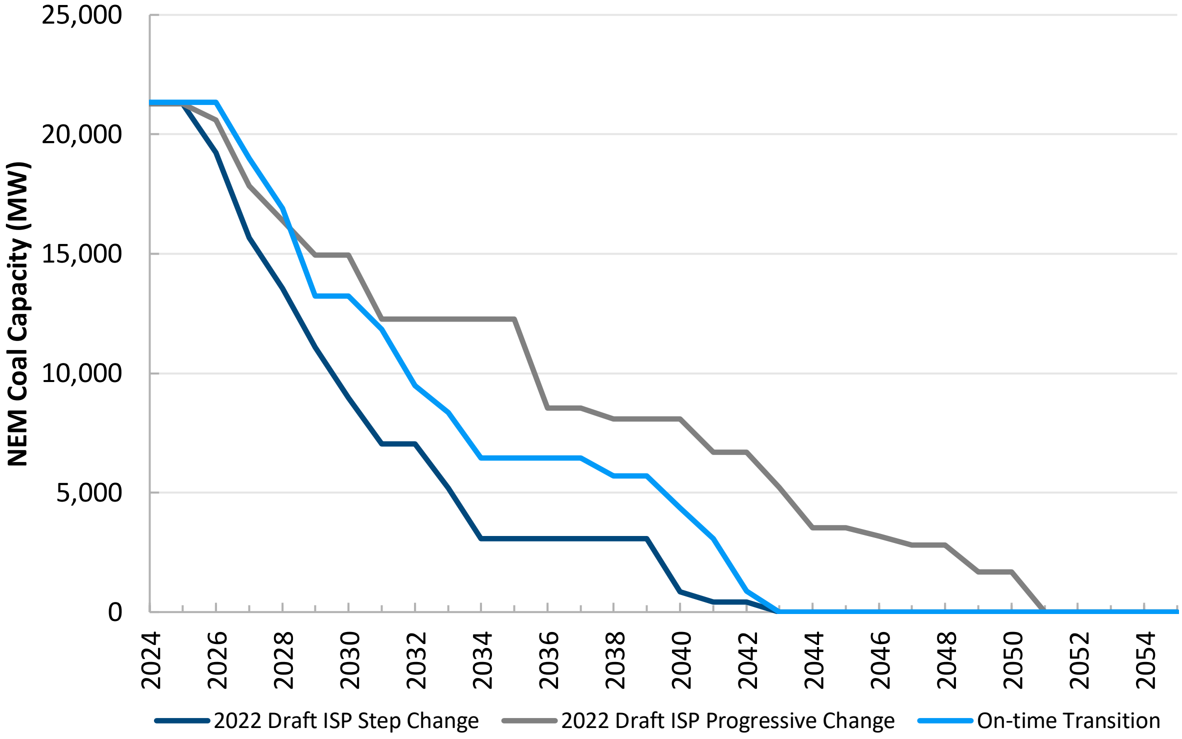
Consequently, coal closures under *On-time Transition* are later and slower than for *Step Change*, especially during the 2020s, but both scenarios align in terms of the date on which the last coal plant exits the system (30 June 2042; Figure 12). Furthermore, coal closures under *On-time Transition* are generally faster and sooner than for *Progressive Change*, implying a lower amount of cumulative emissions under *On-time Transition* – and hence this scenario's alignment with a lower warming scenario and associated CO_2-e budget – than *Progressive Change*. Specifically, *On-time Transition* is aligned with a c.2°C global warming scenario, while *Progressive Change* is aligned with a 2.6°C warming scenario.

,

[80] Baringa understands Yallourn would have closed even earlier than 2028 but for a financial arrangement struck with the VIC Government, to prolong Yallourn's life to 2028.

[81] Marty Silk, *Qld govt rules out any coal plant closures*, 04 May 2022, https://7news.com.au/politics/qld-govt-rules-out-any-coal-plant-closures-c-6678323

Figure 12: Installed coal plant capacity across the NEM, as at 30 June of each year



Sources: AEMO; Baringa Partners LLP

Table 4: Summary of key input assumptions

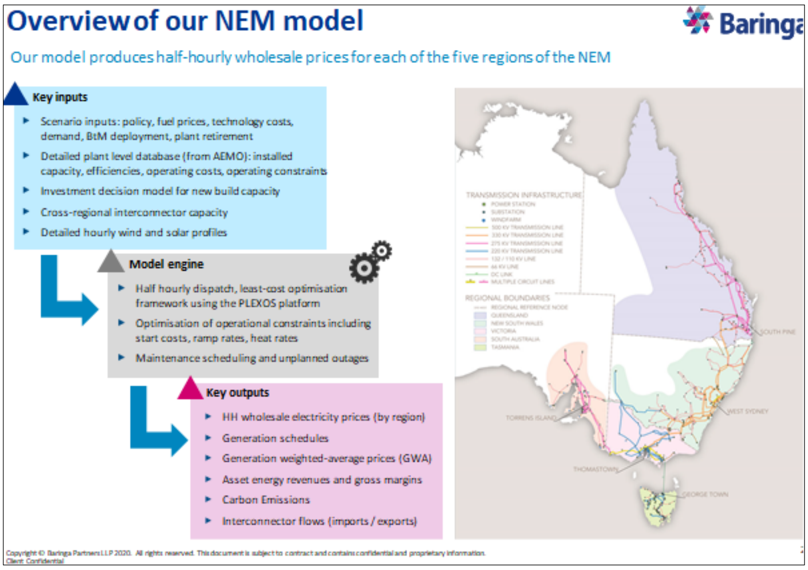
Driver	Assumption	*On-time Transition* scenario	*Delayed Transition* scenario
Policy	Carbon price	None – but enduring (i.e., post-2030) green value exists for renewables	As per *On-time Transition*
	Integrated System Plan	New interconnection and transmission implemented as per AEMO's Draft 2022 ISP *Optimal Development Path*	All intra- and inter-regional transmission augmentations under *On-time Transition* are delayed by 3 years
	State-based renewable targets	First 2-3 rounds of VRET and QRET auctions proceed. Also, 12 GW of new renewables capacity assumed to enter in NSW as per legislation (GWh equivalent), capacity mix driven by relative economics of onshore wind and solar.	As per *On-time Transition*
Demand	Underlying residential and business demand	AEMO Draft 2022 ISP *Step Change*	As per *On-time Transition*
	Rooftop solar and residential storage	AEMO Draft 2022 ISP *Step Change*	As per *On-time Transition*
	Electric vehicle (EVs)	AEMO Draft 2022 ISP *Step Change*	As per *On-time Transition*
	Hydrogen	AEMO Draft 2022 ISP *Step Change*	As per *On-time Transition*
	Electrification (business and residential)	AEMO Draft 2022 ISP *Step Change*	As per *On-time Transition*
Commodity prices	Gas prices	LNG netback prices: latest ACCC LNG netback series, then US Henry Hub prices	As per *On-time Transition*
	Coal prices	Asian coal export price for 'uncontracted' plant (Japan coal prices less transport costs)	As per *On-time Transition*
Capacity mix	Coal plant retirements	Retire coal plant at end of 50-year life (subject to economic test), or earlier if there is a public announcement or significant adverse economics.	As per *On-time Transition*
	Gas plant retirements	As per AEMO *Generation Information* webpage	As per *On-time Transition*
	Technology costs	Baringa internal cost assumptions	As per *On-time Transition*

This page is left intentionally blank

A.2 Overview of modelling approach

Baringa's model for the NEM consists of both short-term (dispatch or operational timeframes) and a longer-term (investment timeframes) models. Inputs into the dispatch model includes demand and commodity prices, and outputs include half-hourly (and more recently, five-minute by five-minute) prices and generator dispatch (Figure 13).

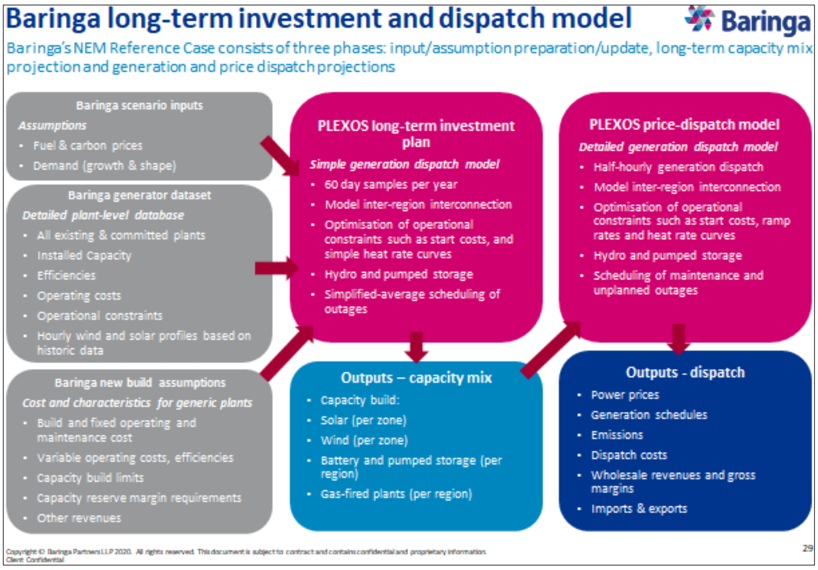
Figure 13: Baringa's dispatch model



Source: Baringa Partners LLP

Baringa's long-term model determines the best (from an NPV perspective) for generation and utility-scale storage capacity to enter the NEM, which is typically around the time of incumbent coal plant closures and, especially under Draft 2022 ISP *Step Change*, increases in demand. There is an interaction and iteration between the short- and longer-term models in that generation-weighted average prices influence, and are influenced by, the timing, magnitude and technology types of new-entrants. Once this iteration has completed and an equilibrium has been reached, outputs from the investment model then feed as inputs into the dispatch model (Figure 14).

Figure 14: The interaction and interconnection between Baringa's market models for the NEM



Source: Baringa Partners LLP

Glossary

Abbreviation	Explanation
$, AUD	Australian Dollars (assumed to be constant $2021 unless otherwise stated)
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BCA	Business Council of Australia
CAPEX	Capital Expenditure
CBA	Cost-benefit analysis
CEIG	Clean Energy Investor Group
CESS	Capital Expenditure Sharing Scheme
CO_2	Carbon Dioxide
CO_2-e	Carbon Dioxide Equivalent
CPA	Contingent Project Application
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
FY	Financial Year (specified as year to 30 June)
GSOO	Gas Statement of Opportunities
GW	Gigawatt
GWh	Gigawatt hour
H_2	Hydrogen
ISP	Integrated System Plan
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelised Cost Of Electricity
LGC	Large-scale generation certificate
MW	Megawatt

Abbreviation	Explanation
MWh	Megawatt hour
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERO	National Energy Retail Objective
NGO	National Gas Objective
NSW	New South Wales
ODP	Optimal Development Path
p.a.	Per annum
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PV	Photovoltaic
QLD	Queensland
RIT-T	Regulatory Investment Test for Transmission
RRN	Regional Reference Node
RRP	Regional Reference Price
SA	South Australia
SRMC	Short-Run Marginal Cost
TAS	Tasmania
TNSP	Transmission Network Service Provider
TWh	Terawatt hour
VIC	Victoria
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital