Australian Energy Market Commission

AEMC
Australian Energy Market Commission

RULE

Directions Paper

National Electricity Amendment (Integrated distribution system planning) Rule 2026

Proponent

Energy Consumers Australia

16 October 2025

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About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

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Summary

1 Distribution network planning is a critical process for ensuring that distribution networks continue to meet the needs of consumers. This has become more pronounced as the National Electricity Market (NEM) is proceeding through a once in a generation transformation from a predominantly fossil-fuelled energy system to one powered by renewable energy.

2 Australian consumers are at the forefront of this transition through record-breaking investment in consumer energy resources (CER). Collectively, rooftop solar is the second-largest source of renewable electricity generation in Australia, and the fourth-largest source of electricity generation, making up approximately 12.4 percent of the country's installed capacity.[1]

3 Effective distribution network planning is needed to realise the opportunities that this transformation is creating. It allows distribution network service providers (DNSPs) to select the most cost-effective options to support both traditional services and the integration of CER into their distribution networks. This could be in the form of network enhancements, but also alternatives such as contracting with virtual power-plants that are being enabled by CER.

4 Effective network planning more broadly is also a key focus of the Australian Energy Market Commission's (AEMC's) strategic narrative and work plan - to consider long-term market design to ensure our frameworks provide the appropriate planning settings, efficient provision of system services and investment signals for the net zero future.[2]

5 It is in this context that we have considered the ability of the existing distribution annual planning process to support DNSPs in meeting the needs of consumers during the transition. We have carefully reviewed the feedback stakeholders provided to our consultation paper and during our public forum. We have also conducted further analysis of the distribution annual planning process in the rules, including commissioning technical advice on gaps in distribution network planning (appendix B).

6 Our assessment is that there are two key issues with the current distribution annual planning process, which is:

- unable to address the emerging challenges for long term distribution network planning; and
- only providing limited information for the low-voltage distribution network, such as information on CER hosting capacity downstream of the zone substation.

7 While DNSPs have started independently addressing the challenges in distribution network planning, this is leading to inconsistencies in long term distribution network planning and reporting across the NEM.

8 We consider that a rule change is needed to improve the effectiveness, consistency and transparency of the long term network planning DNSPs currently undertake for their distribution networks. For example, by requiring DNSPs to prepare and publish a long term plan (e.g. over a 20-year horizon) for their distribution networks.

9 Better and more transparent planning will also help distribution network users, including consumers, to understand how the distribution network is expected to change in future. They will then be better placed to make informed and efficient investments in CER.

10 Similarly, DNSPs have also begun independently improving visibility of their low-voltage networks

1 Clean Energy Council, Rooftop solar and storage biannual report, 2024, p.2.

2 Australian Energy Market Commission, A consumer focussed net zero energy system - The Australian energy Market Commission's vision for our shared energy future, September 2024, p. 7.

through ongoing changes to distribution network data reporting. While this is a positive step forward, related consistency, effectiveness and transparency issues exist. We consider that without change the existing data collection and disclosure obligations will not be fit for purpose in a high CER environment.

11 A rule change is needed to address the issues with the existing data visibility obligations while also creating consistent low-voltage data collection and reporting arrangements across all DNSPs. These arrangements should guide data collection by the DNSPs, and should allow for updates as more information becomes available through new devices such as smart meters and inverters. This would then allow CER investors and consumer agents to more readily engage with distribution network data across the NEM.

12 This directions papers sets out, for consultation with stakeholders, three different policy options that we consider would address the identified shortcomings with the current the distribution annual planning process in the rules.

13 The feedback we receive to this directions paper will then inform the draft policy positions we will adopt for our draft determination and draft rule.

We are seeking your views on our proposed policy options to improve distribution network planning in the rule

14 We consider that there are three alternative policy options that can address the shortcomings we have identified with the current distribution annual planning process in the rules:

- Policy option 1 - implement a new strategic planning process to directly address the emerging challenges in distribution planning, while also reforming the existing distribution annual planning process to improve transparency and data availability.
- Policy option 2 - reform the existing distribution annual planning process to not only improve transparency and data availability, but also provide a longer term plan for DNSPs' distribution networks.
- Policy option 3 - replace the existing distribution annual planning process with a new strategic planning process while also improving transparency and data availability

15 The elements of these three different policy options have been summarised in Table 1. Each of them has distinct advantages and disadvantages.

Table 1: Overview of the three policy options to reform distribution network planning

Policy Option	Central policy approach	Proposed planning horizon	Creates a new strategic planning report	Status of distribution annual planning report	New data transparency obligations replacing existing DAPR data
1	New strategic planning report and reformed distribution annual planning report	20 years	Yes, reported every 5 years as input to capital expenditure plan	Retained, aligned to strategic planning report	Yes

Policy Option	Central policy approach	Proposed planning horizon	Creates a new strategic planning report	Status of distribution annual planning report	New data transparency obligations replacing existing DAPR data
2	Reform distribution annual planning process to incorporate strategic planning	10 years	No	Retained with improved strategic planning	Yes
3	New strategic planning report replaces distribution annual planning process	20 years	Yes, reported every 5 years as input to capital expenditure plan	Replaced with an annual update	Yes

16 Policy option 1 would allow a targeted response to be adopted for each of the shortcomings identified with the existing distribution annual planning process. At the same time, policy option 1 may result in some duplication between the planning processes, and would likely require more time and be more costly to implement than the other options.

17 Policy option 2 would likely be less costly and faster to implement as it is focused on reforming the existing distribution annual planning process. However, we anticipate the long-term planning process would be less robust than the process proposed in policy options 1 or 3 as it would remain an annual process.

18 Policy option 3 would be less costly to implement than policy option 1 as the existing distribution annual planning process would be replaced by the proposed strategic planning process. However, the removal of the annual planning process would require some changes in reporting while potentially reducing transparency on the near-term expected state of distribution planning processes.

19 A key element of each policy option is the proposal for a longer planning horizon.

20 We currently have a soft preference for policy option 1, but we acknowledge that this could be a complex change for DNSPs to implement.

21 The Commission is seeking stakeholder feedback on our evaluation of the policy options, including if there are potential modifications that would improve them.

22 The Commission is also seeking to understand if there is strong stakeholder support for one of the proposed policy options. The rationale for that support will then inform the approach we take in the draft determination.

We are also seeking your views on our proposed approach to improve reporting of distribution network data in the rules

23 We also consider that new reporting requirements are needed for distribution network data, regardless of which policy option is adopted.

24 Under our proposed approach, there would be new distribution network data reporting obligations created in the rules. This obligation would require the DNSPs to report their network data in accordance with network data reporting guidelines that we propose would be developed by the Australian Energy Regulator (AER).

25 The rules would also set out principles for the AER to follow when developing the network data reporting guidelines. These principles would require the AER to take into account different factors when determining if certain data types or data sets should be reported on by the DNSPs.

26 For example, the principles could require the AER to consider the consumer benefit of requiring DNSPs to publish particular data types or data sets and whether this benefit is sufficient to offset the costs to DNSPs of publishing the data types or sets.

27 We consider that this approach would address the identified issues with the publication and reporting of distribution network data. In particular, that it would lead to improvements in the visibility of the low-voltage distribution network.

28 Our proposed reporting approach would also provide sufficient flexibility to allow the reporting requirements to be updated so that they are aligned with the outcomes of the broader work programs currently being progressed. For example, the *Data Sharing Arrangements – M2* project that is part of the national CER roadmap.

29 We are seeking stakeholder feedback on the proposed distribution network data reporting requirements, including whether stakeholders agree it is sufficiently flexible to allow alignment with the outcomes of the broader work program.

Submissions are due by 13 November 2025

30 There are multiple options to provide your feedback throughout the rule change process.

31 Written submissions responding to this consultation paper must be lodged with Commission by 13 November 2025 via the Commission's website www.aemc.gov.au.

32 There are other opportunities for you to engage with us, such as one-on-one discussions. See the section of this paper about "How to make a submission" for further instructions and contact details.

Question 1: Does the purpose of the proposed strategic planning process in policy option 1 need to be outlined in the rules?

Do you agree that there would be benefits from outlining the purpose of the proposed strategic planning process in the rules?

What do you consider would be the benefits? Would there also be any unintended consequences?

Do you agree with our proposed purpose for the strategic planning process? If not, what do you consider should be the purpose of a strategic planning process?

Do you agree that the proposed purpose should reflect the National Electricity Objective?

Question 2: Would a 20-year planning horizon most effectively support DNSPs to strategically plan their networks?

What are the potential benefits (qualitative and quantitative) of applying our proposed 20-year planning horizon for strategic plans?

What are the potential costs (qualitative and quantitative) of applying our proposed 20-year planning horizon for strategic plans?

Are there any other broader considerations that would support or prevent DNSPs from adopting the proposed 20-year planning horizon? For example, does the planning horizon align well or poorly with other processes in the broader planning framework (e.g. RIT-D, joint planning requirements)?

Would an alternative planning horizon be more beneficial for the strategic planning of distribution networks by DNSPs (e.g. a 10-year planning horizon)? What would be the costs and benefits of these alternative planning horizons compared to the proposed 20-year planning horizon?

Question 3: Is scenario analysis the most effective approach for addressing the uncertainty in a long planning horizon?

Do you agree with our proposed requirement for DNSPs to adopt scenario analysis for the proposed strategic planning process under policy option 1?

What do you consider would be the benefits of using scenario analysis and the potential issues?

Would requiring scenario analysis improve the transparency of DNSP strategic planning?

Do you agree with the proposal for DNSPs to develop their scenarios in accordance with AER guidelines? If not, what would be the difficulties with this approach?

What would be the benefits of requiring DNSPs to instead follow the AER's existing forecasting best practice guidelines? What would be the issues with this approach, noting that the guidelines are currently produced for AEMO's ISP process?

Question 4: Does the IASR provide the right baseline inputs for the proposed strategic planning process under policy option 1?

Do you agree with our proposal to require DNSPs to use the IASR as baseline inputs for the strategic planning process?

What do you consider are the benefits of this approach? Are there any limitations that need to be addressed?

Is there sufficient flexibility in the proposed process for DNSPs to reflect local, granular requirements when preparing their strategic plans? If not, how can greater flexibility be provided, and what would be the costs and benefits?

Do you agree that DNSPs should be required to declare and justify when they adopt different inputs, scenarios and assumptions than the IASR?

Is oversight of these declarations needed? How could this be achieved, and what would be the costs and benefits of requiring greater oversight?

Question 5: Should the proposed strategic planning process be linked to the regulatory proposal process in Chapter 6 of the NER under policy option 1?

Do you agree that the proposed strategic planning process should draw on and inform the regulatory proposals that DNSPs already prepare?

What do you consider are the advantages and disadvantages of this approach? Would it be possible to address the disadvantages in our proposed process?

Do you agree with our proposal to require the proposed strategic planning process to be consistent with a DNSP's regulatory proposal, including its capital plans? What do you consider are the benefits and challenges of this approach?

Should the proposed strategic planning process use the existing consultation requirements in Chapter 6 of the NER? What do you consider are the advantages and disadvantages of this approach?

Are there others parts of the regulatory proposal process that the proposed strategic planning process should be linked to? What would be the advantages and disadvantages of creating further links than already proposed?

Question 6: Does the distribution annual planning process require an explicit purpose in the rules under policy option 1?

Do you agree that it would be beneficial to articulate the purpose of the distribution planning process in the rules under our preferred policy option?

Do you consider that the proposed purpose helps clarify how the distribution annual planning process fits into the broader planning framework in policy option 1?

Do you agree with our proposed purpose? If not, what should be the purpose of the distribution annual planning process under our proposed policy option 1?

Question 7: Does the distribution annual planning report need to be streamlined under our proposed policy option 1?

Do you agree with our proposal in policy option 1 for the DAPR to focus on reporting planning outcomes and not also report on network data (noting our proposal for separate network data reporting obligations)?

If so, what planning outcomes should be captured by the DAPR? Would it be sufficient to capture the outcomes of the annual planning review as well as the existing reporting requirements for RIT-D projects and joint planning in Schedule 5.8 of the rules? Are there any other planning outcomes that also need to be captured in the DAPR?

Is there other information that should also continue to be reported in the DAPR in policy option 1, noting that we are not proposing to make the report more dynamic?

Question 8: Does network data need to be subject to a separate reporting requirement from the DAPR?

Do you agree with our proposal for the network data currently reported in the DAPR to be subject to

separate reporting requirements?

If so, do you agree that these requirements need to be flexible to accommodate likely changes in data usage and reporting due to other work currently underway (e.g. under the national CER roadmap)?

Would this be best achieved through guidelines, such as the proposed network data and reporting guideline? If not, is an alternative approach needed, and what would be the costs and benefits of this alternative?

Is the AER the appropriate market body to be responsible for developing and maintaining the proposed network data and reporting guideline?

Do the proposed principles for the guidelines strike the right balance between encouraging transparency, innovation in data collection and reporting, and disincentivising improved data capabilities with the costs that data collection and publication create?

Should the AER, or other appropriate market body, be able to gather and report on other data that is not related to network planning? For example, inverter setting compliance that may be available to DNSPs through their CSIP-Aus connections associated with the backstop mechanism rollouts? What would be the costs and benefits of not restricting the guidelines to network data?

Question 9: Do you agree our proposed policy option 1 would best be implemented over seven years?

Do you agree that our proposed reforms would need to be implemented in stages? If not, what do you consider to be a better implementation path?

Do you consider that our proposed implementation stages for policy option 1 would likely be met? If not, what timeframes are needed? Would an alternative transition period be needed?

Do you support our proposal for DNSPs to produce an implementation plan under policy option 1? What do you consider are the advantages and disadvantages of this approach?

Question 10: Can the current distribution annual planning process be reformed to effectively deliver strategic planning and transparency?

Do you consider that the distribution annual planning process can be reformed to provide both strategic planning and transparency of the current and near term state of distribution networks?

If so, what changes are needed? Have they all been captured by our proposed reforms to:

- implement separate network data reporting requirements
- amend the planning horizon to 10 years
- clarify the purpose of the distribution annual planning process
- amend the existing stakeholder engagement obligation to explicitly require DNSPs to draw on stakeholder input from other NER processes.

Are there any additional reforms that would be needed to ensure that the distribution annual planning process would deliver strategic planning and transparency?

Do you agree that a 10-year planning horizon would be more effective in supporting long term strategic planning for policy option 2? If not, what do you consider are the advantages and disadvantages of a 10-year planning horizon?

Would a 20-year planning horizon be more effective, as proposed for policy options 1 and 3? What do you consider would be the advantages and disadvantages of this longer planning horizon under policy option 2?

Question 11: Have all the advantages and disadvantages of reforming the existing distribution annual planning process under policy option 2 been identified?

Do you agree with our assessment of the potential advantages and disadvantages of our proposed policy option 2?

Do you consider that these potential advantages outweigh the disadvantages of policy option 2, including faster and simpler implementation, and the possibility of duplication with the revenue determination process?

Question 12: Do you agree with our relative assessment of policy option 2 (reforming the distribution annual planning process) against policy option 1 (reforming the existing annual process and implementing a strategic planning process)?

Do you agree that we have captured the material relative advantages and disadvantages of this alternative approach against our preferred approach?

If not, what do you think needs to be included in our assessment of policy option 2 against our assessment criteria? Would this change the overall assessment of policy option 2 against our preferred approach, policy option 1?

Question 13: Have all the advantages and disadvantages of replacing the existing distribution annual planning process with the proposed strategic planning process under policy option 3 been identified?

Do you agree with our assessment of the potential advantages and disadvantages of our proposed policy option 3?

Do you consider that these potential advantages outweigh the disadvantages of policy option 3, including greater focus on strategic planning and the possibility of reduced transparency on the expected near-term state of distribution networks?

Question 14: Do you agree with our relative assessment of policy option 3 (replacing the distribution annual planning process with the proposed strategic planning process) against policy option 1 (reforming the existing annual process and implementing a strategic planning process)?

Do you agree that we have captured the material relative advantages and disadvantages of policy option 3 against policy option 1?

If not, what do you think needs to be included in our assessment of policy option 3 against our assessment criteria? Would this change the overall assessment of policy option 3 against policy option 1?

Question 15: Would our proposed policy options create a best practice process for strategic distribution network planning?

Have we captured the key elements of strategic distribution network planning and do these reflect best practice? Do these three proposed policy options represent the broad spectrum of options that the Commission should consider?

Do you consider that each of our proposed policy options are likely to be workable in the NEM? Are there any additional models that we should consider, including a hybrid of some of the proposed policy options?

Is there a proposed policy option you strongly support? Which feature(s) of this policy option do you consider are particularly effective? Is there a feature(s) of this option that you consider is problematic and why?

Is there a policy option that you consider is unlikely to be workable in the NEM? Which feature(s) of this policy option do you consider are particularly problematic and why?

Is there a proposed policy option you strongly disagree with? Which feature(s) of this policy option do you consider are particularly problematic and why? Are there any feature(s) of this policy option that you consider would be effective and why?

Question 16: Would our proposed policy options be consistent with the broader work programs currently underway?

Do you agree that our proposed policy options are consistent with the broader work programs?

If not, do you consider it is possible for our proposed policy options to be consistent with the other work programs? What change to the policy options do you consider would be needed and how would that address your concerns?

Are there other work programs that we have not considered that would also be impacted by our proposed policy options? What do you consider would be the impact of our proposed policy options on these other work programs? Do you believe any further reforms to the distribution planning process in the rules would be needed?

How to make a submission

We encourage you to make a submission

Stakeholders can help shape the solution by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and contributes to well-informed, high quality rule changes.

How to make a written submission

Due date: Written submissions responding to this draft determination must be lodged with the Commission by 13 November 2025.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code ERC0410.[3]

Tips for making submissions on rule change requests are available on our website.[4]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[5]

Next steps and opportunities for engagement

There are other opportunities for you to engage with us, such as one-on-one discussions.

The Commission will also hold a public forum for this directions paper on 5 November 2025. Further details, including a registration link, will be provided on the project webpage once they are available.

For more information, you can contact us

Please contact the project leader with questions or feedback at any stage.

Email:	submissions@aemc.gov.au
Telephone:	02 8296 7800

3 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.

4 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3.

5 Further information about publication of submissions and our privacy policy can be found here: https://www.aemc.gov.au/contact-us/lodge-submission.

Contents

1 Introduction

We have prepared this directions paper to test our proposed policy options to improve long-term distribution planning in the rules and support greater transparency of the electricity distribution network. We consider that there are multiple ways that this can be achieved, each of which has its own advantages and disadvantages. We are interested in stakeholder feedback on each of these proposed policy options, including if stakeholders have a strong preference for one of the proposed options or if they think one is unworkable.

We have evaluated each of these policy options against the broader backdrop of changes to the distribution network. Distribution networks are increasingly being required to support two-way energy flows due to the uptake of consumer energy resources (CER) by energy consumers. The once-clear divide between supply and demand is blurring, creating a more complex, but also more flexible system - one that opens up greater opportunities, including for CER uptake, and the potential for lower costs for consumers.

Effective distribution network planning supports this transition by ensuring Distribution Network Service Providers (DNSPs) proactively plan their networks for these ongoing, long-term changes in network usage. Such effective distribution network planning also supports DNSPs to identify new opportunities that these changes present for their networks, including through the potential for CER and other non-network options to defer network expenditure.

We have considered whether the current distribution annual planning process in the National Electricity Rules (NER) is sufficient to support ongoing effective distribution planning by DNSPs. Chapter 2 of this directions paper sets out the material issues we consider need to be addressed in this rule change based on the original rule change request from Energy Consumers Australia (ECA) and subsequent stakeholder feedback. We have also set out in section 2.3 the reasons for not addressing the other issues raised in the rule change request.

Chapter 3 outlines the three potential policy options we consider would most effectively address the issues identified in chapter 2 based on our assessment criteria. We consider each of these policy options would reform distribution-level planning to improve long-term planning of the distribution network in the rules whilst also supporting greater transparency of network hosting capacity. We have also outlined the potential implementation considerations of our proposed policy options.

Chapter 4 outlines the next steps in the rule change process. Appendix A provides our assessment of the two primary policy approaches that stakeholders supported in their submission. We considered the merits of not reforming the current distribution annual planning process in anticipation that other reforms might address the identified issues. We also considered the merits of implementing the proposed Integrated Distribution System Planning (IDSP) process.

1.1 Context and background

This project was commenced in response to a rule change request submitted by ECA on 22 January 2025. ECA expressed its concerns with the current distribution annual planning process in its rule change request and proposed reforms to address the identified issues. It considers that distribution networks are not being planned effectively under the current annual planning process in rule 5.13 of the NER (further information on the planning process is at appendix A). The planning process is conducted over a minimum five-year planning horizon, with the outcomes published in the Distribution Annual Planning Report (DAPR), per the requirements of schedule 5.8 of the NER. The DAPR also includes a high-level summary of the DNSP's regulatory investment

test for distribution (RIT-D) projects and any joint planning activities they have undertaken (schedule 5.8 of the NER).

ECA has submitted that the current planning process does not result in:

- adequate consideration of the uptake of CER
- sufficient incorporation of outcomes of the biennial Integrated System Plan (ISP)
- sufficient data to fully inform the ISP process
- proactive engagement with communities.[6]

Without reform, ECA believes these issues will lead to:

- curtailment of energy generated from CER
- lower utilisation of network assets
- active communities not contributing to the planning of local networks.[7]

ECA also considers that there is a need for greater transparency of distribution networks and network planning. It considers that the lack of transparency is preventing more rigorous benchmarking and cross-comparisons of DNSPs by the Australian Energy Regulator (AER) and interested parties. It also considers that the lack of transparency is preventing consumers, communities and other stakeholders, such as consumer agents, from making informed investment decisions in CER, to the detriment of the investor and the network.[8]

1.1.1 The proposed Integrated Distribution System Planning process and Network Data and Insights Roadmap

ECA has proposed addressing these issues by replacing the existing distribution annual planning process with a new biennial IDSP process. The IDSP process would require each DNSP to release a planning report every two years, alternating with the ISP. ECA considers that it would allow the IDSP process to both draw on and inform the modelling of the ISP.[9] The IDSP's planning horizon would be 20 years.[10]

The IDSP process would also require DNSPs to:

- undertake proactive engagement with a broader range of stakeholders, including consumers and communities
- develop more detailed forecasts on the uptake of CER
- publish (in the IDSP or via a portal) a range of data on the update of CER, network usage, and
- publish different scenarios for future network developments.[11]

These changes are intended to improve the quality and transparency of distribution network planning. ECA believes this would benefit consumers and third parties, including through improved utilisation of existing distribution network infrastructure.[12]

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6 Energy Consumers Australia, Rule change request, Integrated Distribution System Planning (IDSP RCR), pp. 8-13. Available on our website: https://www.aemc.gov.au/rule-changes/integrated-distribution-system-planning.

7 IDSP RCR, pp. 8-12.

8 IDSP RCR, pp. 9-12.

9 IDSP RCR, p. 14.

10 IDSP RCR, p. 15.

11 IDSP RCR, pp. 14-18.

12 IDSP RCR, p. 19.

The proponent has proposed a Network Data and Insights Roadmap that would support a transition to the IDSP model

ECA is also proposing to require DNSPs to produce a Network Data and Insights Roadmap. DNSPs would be required to outline in their individual roadmap how they will meet the requirements of the IDSP process over an initial seven-year period. Data to be included in the roadmap would include plans to develop the capability to collect, utilise and publish more data at greater spatial granularity.[13] This would support the transition from the existing planning process to the IDSP process while also allowing for greater accountability of DNSPs.

1.1.2 We received broad feedback from stakeholders to our consultation paper

We consulted on ECA's rule change request, including the proposed IDSP process, in our consultation paper, published on 26 June 2025. We received feedback from 30 stakeholders through written submissions and also heard further stakeholder views during our public forum on 14 August 2025.[14]

We thank stakeholders for taking the time to provide their views and relevant evidence through their submissions. It has informed our assessment of the issues set out in chapter 2 as well as our assessment of the policy options set out in chapter 3.

1.2 Related work and reform

There are several recent and ongoing rule changes that are relevant to this rule change. They include the:

- final determination and rule for *Including distribution network resilience in the National Electricity Rules* [15]
- final determination and rule for *Improving consideration of demand-side factors in the ISP* [16]
- *Real-time data for consumers* rule change request process.[17]

We note that we have considered the final determinations for the first two rule changes listed above when assessing the materiality of the issues set in chapter 2.

In addition, there are several processes led by other agencies and market bodies that may have implications for this rule change request:

- the AER's low-voltage network visibility project [18]
- the National Consumer Energy Resources (CER) Roadmap, particularly the data sharing arrangement project, which forms part of national reform priority M2 [19]
- the Australian Energy Market Operator's (AEMO's) ongoing work to develop a CER Data Exchange [20]
- the NSW Transmission Planning Review 2025.[21]

13 IDSP RCR, pp. 13-15.

14 Written submissions to the consultation are available on the project's webpage: https://www.aemc.gov.au/rule-changes/integrated-distribution-system-planning.

15 AEMC, Including distribution network resilience in the national electricity rules, Rule determination, 8 May2025.

16 AEMC, Improving consideration of demand-side factors in the ISP, Rule determination, 19 December 2024.

17 AEMC, Real-time data for consumers, Draft rule determination, 11 September 2025.

18 Australian Energy Regulator (AER), *Network visibility project*, accessed 23 September 2025.

19 Department of Climate Change, Energy, the Environment, and Water, *Energy Ministers agree to the National Consumer Energy Resources (CER) Roadmap*, accessed 23 September 2025.

20 Australian Energy Market Operator (AEMO), *Consumer Energy Resources (CER) Data Exchange*, accessed 23 September 2025.

21 NSW Government, *NSW Transmission Planning Review 2025*, accessed 23 September 2025.

We have considered how our different proposed policy approaches would interact with each of these processes (section 3.5). We consider that our proposed policy approaches are consistent with these other processes and sufficiently flexible to accommodate any potential outcomes.

2 We have identified emerging challenges for the distribution annual planning process

Network planning is an essential function for DNSPs. It enables them to anticipate and meet the future demands on their networks, and to maintain network capability. A well-functioning distribution network planning process is also in the long term interest of consumers as it helps DNSPs to ensure that their distribution networks can transport the optimum amount of energy with the right reliability at the lowest cost.

Under a well-functioning planning process, DNSPs proactively identify the parts of their networks that are likely to face challenges such as emerging supply or demand constraints, ageing infrastructure or system reliability issues. Emerging challenges would be identified with sufficient lead time to take advantage of synergies, and to inform interactions with other developments. DNSPs can then assess through their planning process the most cost-effective options for addressing these challenges while meeting future user demands. This could include network upgrades and/or non-network options, such as demand management or contracts with virtual power plants.

A well-functioning planning process also provides transparency on the current and expected future condition of the distribution network. This allows network users to understand the network's capacity now and in the future, helping to determine the best locations for proposed loads (e.g. data centres, vehicle chargers, industrial developments), generation and storage.

Consistent with this, we consider that the current distribution annual planning process in the rules has two purposes:

- **Efficient network planning**: By identifying requirements for future value-adding network services (e.g. required two-way capacity and reliability), and by delivering those services in a timely manner and at least cost.
- **Transparency and information sharing**: DNSPs provide a broad range of stakeholders with information on their network's current and near-term state, including about existing system limitations and how such limitations will be addressed, to enable them to make informed decisions and contribute to the planning process

However, our evaluation of the current distribution annual planning process is that it is no longer meeting either purpose effectively. As ECA identified in its rule change request, the ongoing changes in the usage of distribution network services by distribution service end users, particularly CER investors, means that the existing planning process does not:

1. Adequately account for the added complexity that the uptake of CER is creating for distribution network planning, including less certain demand growth than in the past (section 2.1).
2. Provide sufficient transparency or data, including for the low-voltage distribution network, to meet the increasing demands on DNSPs for local information on the current and future planned state of the low-voltage network (i.e. below the zone substation) to support the integration of CER (section 2.2).

ECA's rule change request also identified other potential issues that it considered needed to be addressed in this rule change request. We have also considered these issues and are proposing not to address them in this rule change process (section 2.3) as the:

- ongoing implementation of the *Improving consideration of demand side factors in the ISP* rule change will improve the quality of DNSPs' inputs for the ISP (section 2.3.1)

- planning process provides limited avenues for creating new incentives for DNSPs to improve network utilisation (section 2.3.2)
- *Including distribution network resilience in the National Electricity Rules* rule change considered whether new consultation requirements were needed specifically for network resilience (section 2.3.3).

2.1 The distribution network annual planning process does not address the emerging network planning challenges

Our assessment is that distribution network planning is becoming more complex and less certain than in the past. Demand growth is less certain than it was, and new technologies such as home batteries, EVs and controllable appliances mean that more options are available to provide energy and meet peak demand. Further, distribution networks now provide energy export and system services, which are impacted by export constraints.

The uptake of CER also means that distribution planning is now more integrated with both behind the meter and transmission connected resources. Distribution planning synergies have always existed between replacement and augmentation expenditure, where near end of life assets could be replaced with larger assets to meet demand growth. These synergies now extend to CER, which can displace distribution network augmentation expenditure, while simultaneously reducing demand on transmission networks and reducing the need for transmission connected resources.

While CER creates opportunities to lower network costs through improved demand management and the possibility of new non-network options, it also creates greater risks for distribution planning. Costs may increase if, for example, demand forecasts are significantly wrong due to unanticipated changes in the uptake of CER, or if CER is poorly orchestrated, prompting DNSPs to make reactive network upgrades or proactively invest in network augmentations that are not eventually needed.

CER uptake is leading to increased interaction between distribution network planning and transmission planning, flowing through to the Integrated System Plan (ISP) and the Electricity Statement of Opportunities (ESOO). This has also been identified in the NSW Transmission planning review which noted that, while transmission network planning has always relied on forecasts of demand and connections, accurate forecasts are becoming more challenging.[22] It attributes this to, among other things, CER and electric vehicles.[23]

Effectively managing the increasing complexity and uncertainty in distribution network planning creates benefits for DNSPs, the broader planning framework (e.g. transmission planning), and ultimately consumers through more effective network investment. However, it is not clear that the distribution annual planning process in the rules is sufficient to meet these challenges. While some stakeholders did consider that the current distribution planning process remains fit for purpose, most stakeholders acknowledged that it could be improved.[24]

We agree that the current process can be improved. Our assessment of the current planning framework and stakeholder feedback is that the process is not:

- Creating a standardised, transparent process for the long-term planning of distribution networks, including the integration of CER (section 2.1.1).

22 NSW Transmission planning review, *Interim Report*, June 2025, p. 85.

23 NSW Transmission planning review, *Interim Report*, June 2025, p. 85.

24 See for example Ergon Energy Network and Energex submission to the consultation paper, July 2025; Energy Networks Australia submission to the consultation paper, p. 2; AGL Energy (AGL) submission to the consultation paper, p. 3.

- Supporting the procurement of non-network options to address system limitations, reducing the pool of alternative investments available to DNSPs (for example, for RIT-D or capital expenditure proposals) (section 2.1.2).
- Sufficiently incorporating the outcomes of the ISP process to create a level of consistency in the planning process to mitigate the risk that distribution networks may not be aligned with the ISP outcomes (section 2.1.3).

2.1.1 The distribution annual planning process does not create a standardised, transparent process for strategic distribution network planning

Under the NER, DNSPs are required to follow the distribution annual planning process. This requires DNSPs to undertake an annual planning review, including industry engagement, with at least a five-year planning horizon. DNSPs are then required to report on the outcomes of their planning review in a DAPR.

ECA raised concerns with the planning horizon in its rule change request. It considered a longer timeframe is needed for a holistic assessment of the changes created by electrification and the uptake of CER.[25] It echoed these concerns in its submission to our rule change where it noted, in relation to the minimum five-year planning horizon, that:

Short DNSP expenditure proposal timeframes result in reactive investments as networks reach capacity... This is an expensive way to upgrade a network, likely resulting in higher electricity bills and potentially deterring the interest and ability of consumers to electrify and install CER, minimising the benefits this has for both participating and all consumers.[26]

Several stakeholders also expressed concerns with the minimum planning horizon and that the current planning process could result in higher network costs in the long term by not requiring DNSPs to undertake long term network planning. For example the Justice and Equity Centre said that:

There is merit in enabling strategic planning over longer time horizons than is currently standard practice. [...] Although DNSPs may be incentivised to focus on this shorter timeframe, longer-term planning is possible and should be encouraged.[27]

We acknowledge DNSPs currently adopt a longer time horizon during the RIT-D process, but this is only for the specific project being considered. DNSPs would similarly adopt a longer planning horizon when undertaking joint planning with Transmission Network Service Providers (TNSPs) as part of the joint planning process as per rule 5.14 of the NER. However, this is again limited to the parts of the DNSP's network impacted by the joint planning. There is therefore limited long term distribution network planning required under the rules.

We also recognise that the lack of long term planning requirements under the rules does not prevent DNSPs from independently engaging in long term planning. For example, Endeavour Energy submitted that:

Network planning is considerably more complex and comprehensive than what is presented in the DAPR. If the DAPR is being used ... as a proxy or "window" into network planning frameworks and decision making processes, we are deeply concerned that this is likely to result in an incomplete and distorted view on actual planning practice.[28]

25 IDSP RCR, p. 9.
26 Energy Consumers Australia (ECA) submission to consultation paper, p 2.
27 Justice and Equity Centre submission to the consultation paper, p. 5.
28 Endeavour Energy submission to the consultation paper, p 12.

It further submitted that:

[we] develop long-term projections to inform strategic planning to cater for new connection growth. In relation to CER, we have also developed forecasting tools to establish long-term CER uptake trends and forecasts consistent with ISP scenarios.

Ergon Energy Network and Energex also jointly submitted that DNSPs' annual planning processes cover much longer planning horizons and that they already develop strategic area plans with a 25-year horizon.[29]

While these submissions demonstrate DNSPs have extensive planning processes in place beyond what is required in the rules, they also highlight the very different approaches that DNSPs have adopted. This may be sensible in light of the varying local factors that DNSPs must consider when planning their networks, such as vastly different rates of rooftop solar in NSW compared to Tasmania.[30] However, it may also lead to vastly different approaches between DNSPs that will make it more difficult for CER investors and other distribution service users to navigate the strategic plans across the National Electricity Market (NEM). The lack of awareness of these strategic plans that is evident in stakeholder submissions also highlights the potential for a lack of transparency in the strategic planning undertaken by DNSPs.

We have undertaken a gap analysis of distribution network strategic planning

We considered that these potential issues warranted further investigation to ensure that they were material and warranted being addressed in this rule change. We asked Ampere Labs to undertake a targeted review of distribution network planning processes to identify potential gaps in the strategic planning of the distribution network undertaken by DNSPs.

The technical note we received from Ampere Labs is set out in appendix B. It provides examples of the types of strategic planning activities that were conducted beyond the minimum 5-year planning horizon including:

- planning for new zone substations in regard to greenfield developments and long-term load growth
- planning for strategic asset retirements beyond the 5-year time horizon
- planning the sub-transmission and dual function transmission network.[31]

Ampere Labs' technical note highlights that the level of transparency of DNSPs' strategic planning of their distribution networks varies greatly. It identifies that TasNetworks takes an integrated approach for its transmission and distribution assets, with a 15-year network strategy while Ausgrid, which also has dual function transmission assets, applies a 20-year investment outlook.[32]

Perhaps more importantly, the note highlights that there is no natural home for publicly available strategic distribution network planning information. While different parts of the distribution planning framework touch on strategic planning and, as highlighted by the DNSPs' submissions, DNSPs voluntarily publish medium to long term planning information, the information is often fragmented, inconsistent and difficult to piece together.[33] This supports the view that there is limited transparency of the strategic plans for distribution networks, limiting the available

29 Ergon Energy Network and Energex submission to the consultation paper, pp. 3-4.
30 AER, *State of the Energy Market 2025*, August 2025, p. 36.
31 Ampere Labs, *Technical Note - Distribution Network Strategic Planning Landscape and Gap Analysis,* October 2025*,* p. 7.
32 Ampere Labs, *Technical Note - Distribution Network Strategic Planning Landscape and Gap Analysis*, October 2025, p. 7.
33 Ampere Labs, *Technical Note - Distribution Network Strategic Planning Landscape and Gap Analysis*, October 2025, p 13.

information to DNSPs' stakeholders on the expected long term state of their distribution networks including the impact of the uptake of CER.

CER integration is not adequately accounted for in the distribution annual planning process

Ampere Labs also identified in its technical note that there were limitations with CER integration in the distribution annual planning process. It found that some DNSPs have begun planning for CER integration in a separate, parallel process to the distribution annual planning process based on an AER guidance note on CER integration expenditure. Ampere Labs notes that while DNSPs have adopted CER hosting capacity definitions, this has been partly to justify CER integration expenditure.[34] It has also led to DNSPs having very different methods for modelling hosting capacity. This can include:

- the underlying calculation method
- forecasting approaches for CER and EV uptake
- scenario development and selection for investment planning.

Ampere Labs also notes that:

Given the relative immaturity of CER hosting analysis (compared to standard planning), it remains unclear how robust and accurate different modelling approaches and assumptions are in developing justifiable investment plans.[35]

Finally, Ampere Labs notes that it is currently difficult to tell how this parallel planning process is reconciled with the distribution annual planning process. Not only is CER integration not a requirement in the NER, but it considers there is a disconnect between the forecasting approach and spatial granularity of the standard planning process and CER hosting capacity analysis.[36] We consider that this is consistent with the issues raised in ECA's rule change request and makes it difficult for distribution service users to understand how a DNSP's network plan relates to its CER hosting analysis. This is before consideration is given to the additional complexity of undertaking this reconciliation across multiple DNSPs in the NEM (e.g. for CER investors operating across jurisdictions).

2.1.2 The existing process is not revealing non-network options that could address identified system limitations

One of the functions of the current distribution annual planning process is to provide an opportunity for DNSPs to draw out proposals for non-network solutions to address identified network limitations. However, we heard from several stakeholders that this is not occurring in the current planning process. AGL, the Clean Energy Council and Endeavour Energy all expressed concerns that the current distribution planning process has not led to a notable upturn in proposals for non-network options.[37] As Endeavour Energy wrote in its submission:

An emerging issue with the DAPR is that it is administratively burdensome to develop, attracts only limited interest from customers and does not generally elicit solutions from non-network proponents to alleviate constraints.[38]

34 Ampere Labs, *Technical Note - Distribution Network Strategic Planning Landscape and Gap Analysis*, October 2025, pp. 9-11.

35 Ampere Labs, *Technical Note - Distribution Network Strategic Planning Landscape and Gap Analysis*, October 2025, p. 11.

36 Ampere Labs, *Technical Note - Distribution Network Strategic Planning Landscape and Gap Analysis*, October 2025, p. 14.

37 AGL submission to the consultation paper, pp. 1, 3 and 5; Clean Energy Council submission to the consultation paper, p. 5; Endeavour Energy submission to the consultation paper, p. 12.

38 Endeavour Energy, submission to the consultation paper, p. 12.

This view was not shared by some DNSPs, such as AusNet which felt that the existing process was sufficient for considering and obtaining non-network options and integrating CER.[39]

Whilst we acknowledge that some DNSPs may feel the current process is working effectively, it is clear that a broad range of stakeholders do not share this view. We consider that there is sufficient evidence that the current process is no longer working as intended in drawing out a range of non-network options across the NEM. It is also not clear that the industry engagement obligations in the distribution annual planning process are facilitating new non-network options as new technology emerges.[40] For example, Ampere Labs noted that while demand management is incorporated into the distribution annual planning process, it has typically been used to alleviate limitations identified at the high voltage level.[41] The uptake of new technologies, such as home batteries and electric vehicles, will create opportunities for cost-effective demand curtailment on the low-voltage network. It is important that the distribution annual planning process operates effectively for these opportunities to be realised and to minimise costs for consumers. This includes encouraging higher rates of network utilisation by minimising the need for new network augmentations.

2.1.3 Distribution network planning is not sufficiently coordinated with the ISP or other network plans

ECA raised concerns with the amount of coordination between the distribution planning process and the ISP in its rule change request. It was concerned that this risked the future distribution system failing to meet the assumptions of the ISP.[42] ECA raised similar concerns in its submission to our consultation paper.[43]

We received feedback from a broad range of stakeholders that provided support for ECA's position that DNSPs do not sufficiently coordinate their plans with the ISP or other DNSPs' distribution network plans including the:

- Business Council of Co-operatives and Mutuals
- Energy Efficiency Council
- Australian Renewable Energy Alliance.[44]

Other stakeholders provided nuanced views. For example, Ausgrid, supported closer integration between DNSP planning and the ISP, but cautioned this needed to be pursued in a way that is consistent with the *Improving consideration of demand side factors in the ISP* rule change. Ausgrid also said that it cannot rely alone on the ISP scenarios for its planning requirements as the ISP scenarios are created at a broad level to provide a common baseline for industry across the NEM. Ausgrid then noted that this means the ISP scenarios do not cater to the level of intra-regional detail needed for distribution network planning.[45]

AEMO also provided similar feedback in its submission. It submitted that:

...there is a limit to the degree of alignment of assumptions and inputs between transmission network planning and distribution network planning as the scenarios used for the ISP will never be

39 AusNet submission to the consultation paper, p. 3.

40 NER clause 5.13.1(e)-(j).

41 Ampere Labs, *Technical Note - Distribution Network Strategic Planning Landscape and Gap Analysis, October 2025*, p. 14.

42 IDSP RCR, p. 13.

43 ECA submission to the consultation paper, p. 2.

44 Business Council of Co-operatives (BCCM) submission to the consultation paper, pp. 2 and 3; Energy Efficiency Council submission to the consultation paper, p. 6; RE-Alliance, submission to the consultation paper, p 2.

45 Ausgrid submission to the consultation paper, pp. 3-4.

granular enough to accommodate the types of local considerations required for distribution network planning.[46]

A practical example of these limitations was provided by Evoenergy, the DNSP for the ACT. It submitted that it faces challenges in drawing on the ISP's scenario as the ACT is part of the NSW NEM region. Evoenergy further submitted that the inputs, scenarios and assumptions prepared by AEMO for the relevant NSW NEM region do not align with its own bottom-up planning assessment for its network. For example, it anticipates much higher rates of EV ownership in the ACT than assumed for the corresponding NSW NEM region.[47]

Other stakeholders also questioned the benefits of closer alignment of the distribution network planning process with the ISP. For example, AGL, agreed there is a need for consistency and transparency in network planning and is supportive of a process that leads to this outcome. However, it considers pursuing a distribution network planning process that leads to greater integration with the ISP needs careful consideration. AGL instead suggested that there could be value in having separate forecasts from the planning processes and validating these against each other.[48]

Our assessment is that the *Improving consideration of demand side factors in the ISP* rule change will strengthen the ISP as a guide for distribution network planning. However, there will still be no requirement in the rules for the DNSPs to consider how their annual distribution network plans align with the ISP. This process gap creates a risk (real and perceived) that the distribution annual planning process will not align with the ISP and its projected futures, even after accounting for demand diversity across the DNSPs. Lack of scenario alignment also makes it difficult to compare distribution and transmission expenditure on a like for like basis, or to determine the impact of forecast updates, where demand might be tracking to a different scenario.

2.2 The distribution annual planning process and the low-voltage network is not sufficiently transparent with the increasing uptake of CER

ECA identified issues with the transparency of distribution network planning and with low-voltage network visibility in its rule change request. It was concerned that these issues would hinder:

- consumers, communities and non-network participants from making informed investments in CER[49]
- the AER and interested parties from ensuring distribution networks are being appropriately judicious when assessing their network capacity, undermining trust in these assessments[50]
- consumers and communities from meaningfully engaging in the planning process.[51]

We received submissions from a range of stakeholders that agreed with ECA's views that there is a lack of transparency of distribution network planning and a lack of visibility of the low-voltage network. This was particularly pronounced around network hosting capacity data.

46 AEMO submission to the consultation paper, p.2.
47 Evoenergy submission to the consultation paper, p. 3.
48 AGL submission to the consultation paper, p. 3.
49 IDSP RCR, pp. 11-12.
50 IDSP RCR, p. 10.
51 IDSP RCR, p. 7.

For example, Cotton Australia supported:

the principle of consumers having access to CER hosting capacity information, particularly if it prevents the energy consumer (and by inference the CER installer) from over-capitalising the installation or becoming hampered by local network constraints.[52]

It also noted that this information had been provided by Essential Energy and Ergon Energy for Cotton Australia's energy research projects.[53]

The South Australian Council of Social Services (SACOSS) similarly provided its strong support for improving transparency of network utilisation by requiring DNSPs to collect and publish greater amounts of more granular data.[54] SACOSS then raised specific concerns with SA Power Networks' "*current approach to managing volatility through tariff design which is based on opaque data analysis pointing to 'system benefits' not founded in transparent localised modelling of network constraints or the reality of human behaviour.*"[55]

Other stakeholders, such as the Clean Energy Council and Red and Lumo Energy, also provided their support for greater network transparency.[56] Red and Lumo also submitted that improved visibility would assist competing service providers to identify and respond to constraints through non-network solutions.[57]

In comparison, submissions from several DNSPs and their industry representatives rejected the proposition that they understate capacity of their network infrastructure in order to justify increased capital expenditure.[58] However, they broadly acknowledged that there were opportunities for further improvements in transparency, particularly for the low-voltage network, though DNSPs have already made improvements.[59] For example, Ausnet stated that it has:

observed increasing demand for low-voltage (LV) network data from communities exploring local energy solutions... As a result, we have already significantly evolved our network data sharing frameworks in line with the proposed outputs from the consultation paper.[60]

Ausnet further notes that it has established a portal that provides extensive network data and visibility to help users understand areas of network constraints.[61]

Some stakeholders, including some DNSPs and their representatives, also thought that other processes would be better positioned to address the identified issues.[62] For example, AEMO pointed to the *Data Sharing Arrangements – M2* and *CER Data Exchange - M2* projects of the national CER roadmap.[63]

Whilst other projects are investigating data, there is a large data component to the current distribution annual planning process that is ultimately reported via the DAPR. As such, there remains a risk of current or emerging duplication and gaps in data reporting between the DAPR

52 Cotton Australia submission to the consultation paper, p. 1.
53 Cotton Australia submission to the consultation paper, p. 1.
54 South Australian Council of Social Services (SACOSS) submission to the consultation paper, p. 5.
55 SACOSS submission to the consultation paper, p 5.
56 Clean Energy Council submission to the consultation paper, p. 4; Red and Lumo Energy submission to the consultation paper, pp. 1-2.
57 Red and Lumo Energy submission to the consultation paper, p 1.
58 See for example, Energy Networks Australia submission to the consultation paper, p 1; Jemena Electricity Networks (Jemena) submission to the consultation paper, pp. 1-2.
59 Energy Networks Australia submission to the consultation paper, p. 1; Jemena, submission to the consultation paper, pp.1-2.
60 Ausnet submission to the consultation paper, p. 1.
61 Ausnet submission to the consultation paper, p. 1.
62 See for example, Energy Networks Australia submission to the consultation paper, pp. 1-2 and 5-6; Ausnet submission to the consultation paper, p. 4; AEMO submission to the consultation paper, pp. 2-3.
63 AEMO submission to the consultation paper, p. 3.

and other processes, unless they also lead to a rule change request to amend rule 5.13 of the NER. The voluntary publication of data, including existing data reported in the DAPR, in other formats also demonstrates that stakeholders are demanding this data in alternative formats. Some stakeholders also highlighted the benefits that the publication will create.[64] However, such publications are currently not required by the distribution annual planning process, or the rules more broadly. This is creating a material risk that the DNSPs are adopting inconsistent processes, making it difficult to assess the information across the NEM (e.g. for customer agents and CER investors). Energy consumers may also have inconsistent access to network planning information outside of the distribution annual planning process and may experience different levels of low-voltage network data transparency, depending on the network and location.

We consider there is a need to address these issues in this rule change. This will ensure that the distribution planning process in the rules continues to provide transparency of distribution network planning and improved visibility of the low-voltage network. However, we acknowledge stakeholder concerns that there are other processes exploring these issues and have considered this when developing our proposed policy options in chapter 3.

2.3 We are not proposing to address the other issues raised in the rule change request

ECA also raised three other issues that it had identified with the current distribution annual planning process in its rule change request. We have carefully evaluated each of these issues following our consultation paper. Our assessment, which has been informed by stakeholder submissions, is that each of these issues does not need to be addressed in this rule change process. Specifically, we consider that:

- the *Improving the considerations of demand-side factors in the ISP* rule change will improve the quality of data provided by DNSPs to the ISP process (section 2.3.1).
- there is limited ability to create or amend incentives for DNSPs to improve network utilisation in the planning process, though we have considered this issue when developing our policy positions (section 2.3.2).
- engagement on network resilience does not need to be specifically carved out in the planning process (section 2.3.3). Distribution network resilience is now explicitly required under the NER due to the *Including distribution network resilience in the National Electricity Rules* rule change, and we did not receive feedback for any further changes.

2.3.1 The ongoing implementation of the Improving consideration of demand side factors in the ISP rule change will improve the quality of DNSP inputs to the ISP

We set out in section 2.1.3 that there is currently no requirement in the rules for the distribution annual planning process to be aligned with the planning inputs and outputs of the ISP. ECA also raised similar issues with how the distribution annual planning process is integrated in the ISP to achieve whole-of-system-planning.[65] In particular, that there remains a disconnect between the planning frequencies, inputs and planning horizons for the distribution annual planning process and the ISP. While ECA acknowledged that the *Improving considerations of demand side factors in the ISP* rule change would improve the granularity of data provided, it did not consider that it would address the other gaps (e.g. the difference in planning horizons).[66]

64 Nexa advisory submission to the consultation paper, p. 2.
65 IDSP RCR, pp. 12-13.
66 IDSP RCR, p 13.

We acknowledge that there was broad in principle support for improving integration between distribution planning and the ISP.[67] As discussed in section 2.1.3 above, we think that there is a case for requiring DNSPs to better incorporate AEMO's ISP assumptions in to their forecasting. However, our assessment is that there is limited evidence at this stage to support the reverse - i.e. further changes to the distribution planning process to improve DNSPs' inputs to the ISP - at this stage.

We understand that AEMO is still implementing the *Improving considerations of demand side factors in the ISP* rule change. As part of this, AEMO is developing Demand Side Factors Information Guidelines to establish and drive a consistent approach for collecting distribution network information from DNSPs.[68] We understand AEMO also aims to harmonise data collection and reporting standards across all DNSPs for the purpose of improving consideration of demand side factors in the ISP, by implementing a gradual approach for DNSPs to meet data requirements and developing standardised processes and templates.[69]

We consider it is important to provide AEMO with an opportunity to implement the *Improving considerations of demand side factors in the ISP* rule change before making further changes. This would allow for the effectiveness of our rule change and AEMO's new processes to be evaluated. It is also consistent with our assessment criteria, most notably the principles of good regulatory practice. We also note that we consider the process AEMO has outlined, including the methodology for distribution network opportunities in the *2025 Electricity Network Options Report*, is sufficient to address the issues ECA raised with DNSP inputs to the ISP.[70]

2.3.2 The planning process provides limited avenues for creating new incentives for DNSPs to improve network utilisation

Multiple stakeholders provided submissions supporting ECA's view that DNSPs have an incentive to choose network options over non-network options, which could result in non-optimal network outcomes, including limited network utilisation.[71] However, this view was not shared by all stakeholders, including DNSPs and their industry representatives.

We have considered how our proposed policy positions can support DNSPs planning their networks to promote the most efficient investments for the long-term interest of consumers. One item considered was whether the existing distribution planning process could be changed to support DNSPs procuring non-network options more easily, where it is in the long-term interest of consumers (chapter 3).

We have also considered how our proposed positions fit within the broader planning framework and other reforms. This includes our pricing review initiated on 25 July 2024, the national CER Roadmap initiated on 19 July 2024 and previous work by us, such as consideration of total expenditure, or totex, as an option in 2019.[72]

After considering these other processes, we are not proposing to make any further changes. While we note the concerns, we have received limited specific evidence to support broader changes to the planning framework. We also anticipate that any broader changes would likely require

67 See for example, BCCM submission to the consultation paper, p. 3; Justice and Equity Centre submission to the consultation paper, p. 8; Clean Energy Council submission to the consultation paper, p. 5.

68 AEMO submission to the consultation paper, p. 1.

69 AEMO submission to the consultation paper, p. 1.

70 AEMO, *2025 Electricity Network Options Final Report*, August 2025, pp. 60-72.

71 IDSP RCR, pp. 6 and 9-10.

72 The pricing review: Electricity pricing for a consumer-driven future (EPR0097), accessed on 3 October 2025, Energy Ministers agree to the National Consumer Energy Resources (CER) Roadmap, accessed on 3 October 2025, AEMC, Integrating distributed energy resources for the grid of the future, Economic regulatory framework review, 26 September 2019, section 7.1.1.

amending Chapter 6 of the NER, which is out of scope for this rule change. Amending Chapter 6 of the NER would be complex and require broader consideration of the economic regulatory framework for distribution networks, which goes beyond the current distribution annual planning process.

We note that the Commission has begun scoping and pre-work for a network regulation review as outlined in our high-level work program. While the Commission is still determining the scope of the review, we expect that the balance of financial incentives between network options and non-network options is likely to be considered. This may provide an opportunity to consider the issues stakeholders have raised in their submissions.

We also note the AER's intention to commence a review of incentive schemes for export services in 2026.[73]

2.3.3 The *Including distribution network resilience in the National Electricity Rules* rule change

ECA also raised concerns in its rule change request about the lack of requirements for DNSPs to engage with communities at risk of extreme weather events in the distribution annual planning process.[74] As noted in our consultation paper, we recently made a final determination to include network resilience in the NER, including an assessment of the current engagement framework between DNSPs and communities in the context of resilience.[75]

We determined that the assessment of resilience expenditure would utilise existing consultation processes in distribution determinations.[76] We further stated in our consultation paper that we were not proposing to reconsider this issue as part of this rule change process unless stakeholders provided new information or raise new issues.[77] We did not receive either evidence of new issues or additional evidence from stakeholders that changes to the distribution annual planning process are needed to improve engagement with communities at risk of extreme weather events. As such, we are proposing not to take any further action on this specific issue.

73 AER, *Low-voltage Network Visibility Phase 3 Final Report*, 31 March 2025, p.18.
74 IDSP RCR, p. 14.
75 AEMC, Including distribution network resilience in the national electricity rules, Rule determination, 8 May 2025.
76 AEMC, Including distribution network resilience in the national electricity rules, Rule determination, 8 May 2025, pp. 28-29.
77 AEMC, Integrated Distribution System Planning, Consultation Paper, 26 June 2025, p. 8 and p. 17.

3 Our proposed policies to address the identified issues

We evaluated different policy approaches to reform the current distribution annual planning process in the rules to address the two overarching issues identified in chapter 2. We considered that the issues lent themselves to three potential policy options:

Policy option 1 - implement a new strategic planning process to directly address the emerging challenges in distribution planning, while also reforming the distribution annual planning process to improve transparency and data availability (Figure 3.1).

Policy option 2 - reform the distribution annual planning process to not only improve transparency and data availability, but also provide a longer term plan for DNSPs' distribution networks (Figure 3.2)

Policy option 3 - replace the distribution annual planning process with a new strategic planning process, while also improving transparency and data availability (Figure 3.3).

We expand on the detail of each of these policy options below.

On balance, we currently have a soft preference for policy option 1 as it allows a targeted response to each of the issues identified in chapter 2. However, we acknowledge that this could be a complex change for DNSPs to implement and may lead to duplication between the planning processes. We think this is less likely with policy options 2 and 3, which rely on a single planning process to address the identified issues. Additionally, policy option 2 may be significantly quicker to implement than policy option 1.

Figure 3.1: Overview of policy option 1

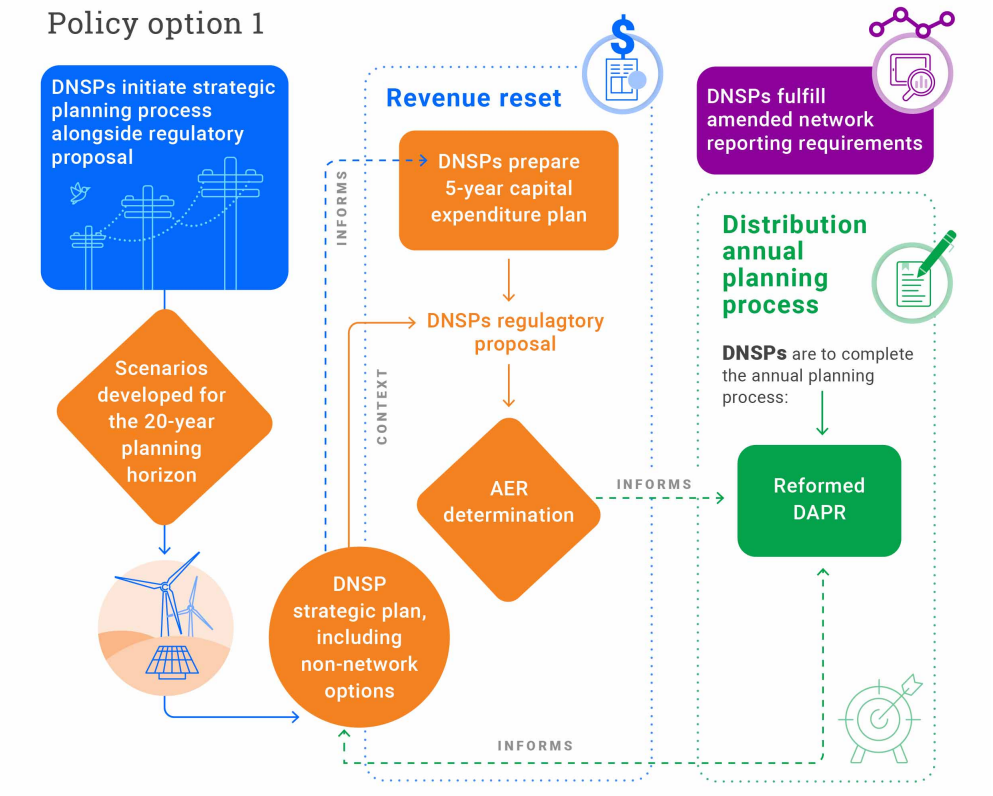


Figure 3.2: Overview of policy option 2

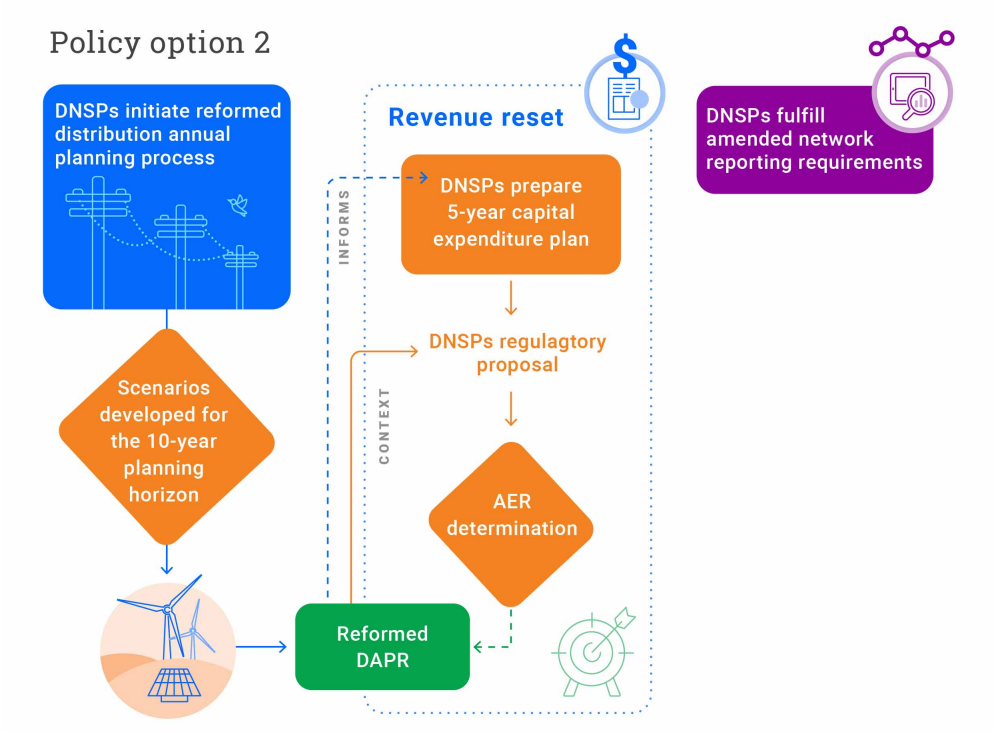
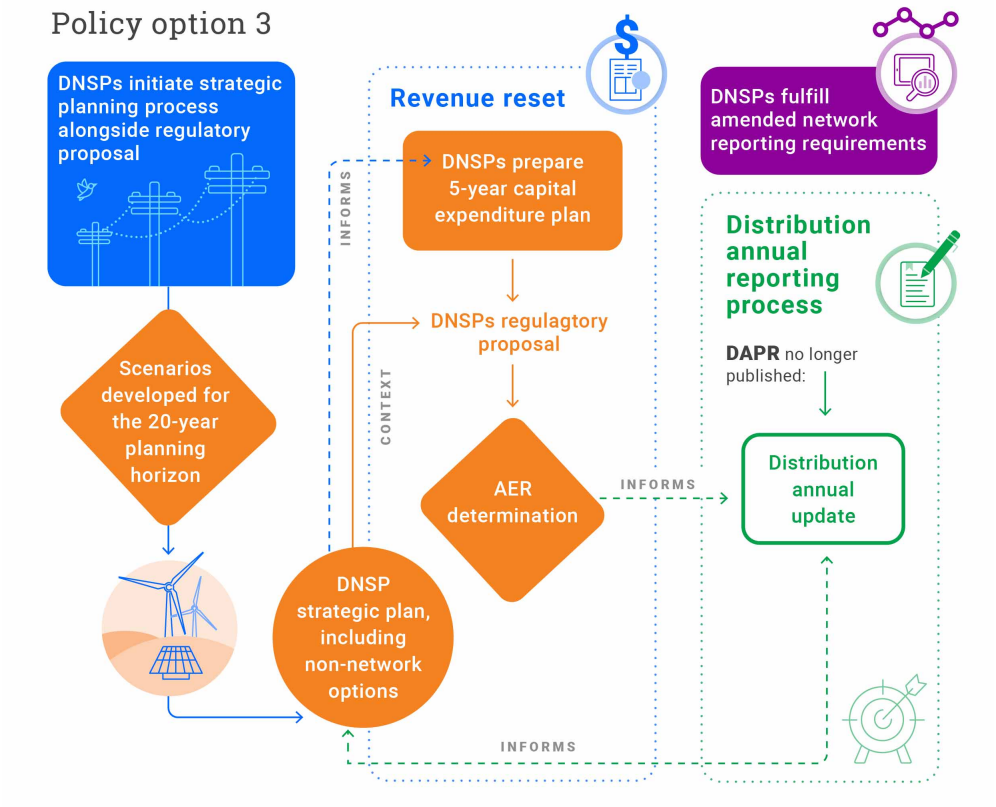


Figure 3.3: Overview of policy option 3



We also considered the two main policy approaches that were supported by stakeholders, specifically:

- Make no changes to the distribution annual planning process.
- Implement the proposed IDSP process in full.

However, our analysis of these approaches indicates that they would not sufficiently address the identified issues or meet our assessment criteria as fully as our proposed policy options (see appendix A for detailed assessments). In comparison, our proposed policy options would:

- promote efficient investment in networks in the long-term interest of consumers (addressing the safety, security and reliability assessment criterion)
- require DNSPs to improve transparency of their distribution networks and planning processes, and reduce transaction costs for third parties (addressing the principles of market efficiency assessment criterion)
- help build trust and social licence by improving oversight of how DNSPs are planning their networks, while also creating a clear implementation plan that aligns with other reforms (addressing the implementation considerations assessment criterion)
- be consistent with the broader direction of reform, providing a predictable and stable planning framework, and promote transparency for stakeholders (addressing the principles of good regulatory practice assessment criterion).

We would like to explore with stakeholders whether they agree with our evaluation of the three policy options we have outlined above. We would also like to confirm if stakeholders strongly support one of these options, as the rationale for that support will then inform the approach we take in the draft determination.

We would also like to understand whether stakeholders believe that modifications to the policy options could better deliver the intended policy outcomes, or if any of the policy options are unworkable in the NEM.

This chapter sets out for consultation with stakeholders:

- Policy Option 1 : implementing a new strategic planning process while reforming the existing annual planning process (section 3.1)
- Policy option 2 : reforming the current distribution annual planning process (section 3.2)
- Policy option 3 : replacing the current planning process with a new strategic planning process (section 3.3).

3.1 Policy option 1 - Implementing a strategic distribution planning process and reforming the existing distribution annual planning process to improve network transparency

As noted above, our current preferred policy option would create two distinct planning processes in the rules:

1. A standardised strategic distribution network planning process that can draw on and inform the regulatory proposals process in Chapter 6 of the NER.
2. A reformed distribution annual planning process to improve transparency on the expected, near-term state of the distribution network.

We have adopted this as our preferred policy option as we consider using two planning processes allows for targeted, tailored solutions to the distinct issues we have identified during

consultations. This section provides more information on each of the underpinning elements of our preferred policy approach (policy option 1) for consultation with stakeholders. It sets out:

- our proposal to implement a strategic planning process for distribution networks in the NER (section 3.1.1)
- how we are proposing to amend the existing distribution annual planning process (section 3.1.2)
- a potential implementation plan for these proposed changes (section 3.1.3).

3.1.1 Our proposed new strategic planning process would create a standardised, transparent approach for DNSPs in the NEM

A new strategic planning process would be created in the NER under our proposed policy option 1. We consider that its role would be to:

1. provide a transparent, consistent strategic planning process for distribution networks, addressing stakeholder concerns that DNSPs are not currently strategically planning their networks especially for the increasing uptake of CER
2. create clearer links between DNSPs' network plans and the broader planning framework (e.g. the RIT-D process and AER revenue determinations)
3. clarify how network planning aligns with the National Electricity Objective.

We provided an overview of how the process would operate in Figure 3.1. We consider that this approach, when combined with our proposed reforms to the distribution annual planning process (section 3.1.2), would support effective network planning in a high and increasing CER environment, improving consumer outcomes over the long term.

This section provides greater information on the different aspects of our proposed strategic planning process, for stakeholder feedback. It sets out our proposed:

- purpose for the strategic planning process
- adoption of a 20 year planning horizon, consistent with the ISP
- requirement for DNSPs to use scenario analysis, with the scenarios reflecting likely future states of the DNSP's networks
- adoption of AEMO's IASR as baseline inputs for the strategic planning process, while providing DNSPs the flexibility to use alternative inputs that better reflect their distribution networks
- reporting approach, requiring DNSPs to submit their strategic plan as a supporting document with their regulatory proposals
- use of the existing consultation process for regulatory proposals to conduct stakeholder engagement for their strategic plans.

Under policy option 1, the strategic planning process would have its purpose established in the rules

We propose to include the purpose of the preferred strategic planning process in the rules. This would assist stakeholders to understand how this process is intended to fit within the broader planning framework. We anticipate this would then make it easier for DNSPs to implement the planning process to achieve its intended outcomes. Stakeholders would also be better placed to review the strategic plans.

We consider that the purpose should align with the National Electricity Objective. This will help assure stakeholders that DNSPs must prioritise the long term interest of consumers when planning their networks. As such, we propose the following purpose:

To require DNSPs to plan efficient investment in those electricity network services that maximise the long term interests of consumers under a credible range of scenarios.

This framing is consistent with the National Electricity Objective. It also reflects our proposed process for the strategic plan, including the use of scenario analysis, which will further encourage consistency in planning approaches between DNSPs.

We are seeking stakeholder feedback on the proposed purpose of the strategic planning process under policy option 1, including whether it should be stated in the rules.

Question 1: Does the purpose of the proposed strategic planning process in policy option 1 need to be outlined in the rules?

Do you agree that there would be benefits from outlining the purpose of the proposed strategic planning process in the rules?

What do you consider would be the benefits? Would there also be any unintended consequences?

Do you agree with our proposed purpose for the strategic planning process? If not, what do you consider should be the purpose of a strategic planning process?

Do you agree that the proposed purpose should reflect the National Electricity Objective?

The proposed strategic planning process would have a 20-year planning horizon

We are proposing to adopt a 20-year planning horizon for the strategic planning process in policy option 1. We have considered the arguments for and against this long planning horizon, namely that it:

- aligns with the ISP[78]
- requires DNSPs to consider the most likely future of their distribution network, including system constraints[79]
- encourages DNSPs to proactively consider how they will manage changing demands on their networks[80] (ECA, CEC)
- would produce forecasts that are more uncertain than for five or ten years [81]
- may not be directly usable by consumers.[82]

On balance, we consider a 20-year planning horizon to be most beneficial for a strategic plan. It would encourage all DNSPs to proactively consider how their networks will look in future (noting that some DNSPs already have 20+ year network plans). Adopting the same planning horizon as the ISP will also make it easier to compare the DNSPs' strategic plans against the ISP's projected future and outcomes (section 2.1.3). This would then contribute to greater transparency for stakeholders, providing assurance that the DNSPs are planning for the increasing uptake of CER. We also acknowledge that the 20-year planning horizon may be of limited value to some stakeholders, though it is not apparent if it would be of any less benefit than a 10-year or 15-year planning horizon.

78 IDSP RCR, p. 17.
79 Clear Energy Council submission to the consultation paper, pp. 4-5.
80 IDSP RCR, pp. 8-9; Clean Energy Council submission to the consultation paper, pp. 4-5.
81 Ergon Energy Network and Energex submission to the consultation paper, pp. 16-17.
82 Ergon Energy network and Energex submission to the consultation paper, pp. 16-17.

We also think that a 20-year planning horizon has advantages beyond those cited above. It will show how the current 5-year development plan fits within the context of long term network reconfiguration, including future new and replacement transmission and subtransmission infrastructure. It will indicate sites, routes and easements that will need to be acquired over time, and show network projects that can be brought forward if demand increases more rapidly than currently anticipated, and it will provide investors in large long term assets, such as batteries or wind generators, insight into where constraints might materialise or be mitigated in future.

We would welcome stakeholder feedback on the likely costs and benefits for strategic planning of our proposed 20-year planning horizon. We are also interested in understanding the costs and benefits of alternative planning horizons for strategic plans. For example, adopting a 10-year planning horizon, as required for transmission planning.

Question 2: Would a 20-year planning horizon most effectively support DNSPs to strategically plan their networks?

What are the potential benefits (qualitative and quantitative) of applying our proposed 20-year planning horizon for strategic plans?

What are the potential costs (qualitative and quantitative) of applying our proposed 20-year planning horizon for strategic plans?

Are there any other broader considerations that would support or prevent DNSPs from adopting the proposed 20-year planning horizon? For example, does the planning horizon align well or poorly with other processes in the broader planning framework (e.g. RIT-D, joint planning requirements)?

Would an alternative planning horizon be more beneficial for the strategic planning of distribution networks by DNSPs (e.g. a 10-year planning horizon)? What would be the costs and benefits of these alternative planning horizons compared to the proposed 20-year planning horizon?

The proposed strategic planning process would require DNSPs to use scenario analysis as part of their planning methodology

We propose requiring DNSPs to adopt scenario analysis as part of their planning methodology for the proposed strategic planning process in policy option 1. Under this approach, DNSPs would be required to robustly analyse different scenarios that represent likely future states of their distribution networks. Requiring DNSPs to consider a range of likely scenarios would:

- partly address the uncertainty of the 20-year planning horizon, by requiring DNSPs to plan for different potential futures
- encourage DNSPs to consider how they would address different contingencies (e.g. lower and higher rates of electric vehicle uptake across their network area)
- be consistent with the approach for the ISP and the forecasting best practice guidelines for the ISP.[83]

We note that there was limited commentary on the use of scenario analysis in submissions to our consultation paper. We would like to better understand what the potential costs and benefits would be of DNSPs using scenario analysis in the proposed strategic planning process. We ask stakeholders to consider not only the quantitative costs and benefits, but also the qualitative ones. For example would it provide stakeholders with greater transparency of likely future states of the distribution networks, noting that DNSPs have little certainty over a 20-year planning horizon. We

83 Rule 5.22 (5.22.8(a)) and AER, *Forecasting best practice guidelines, August 2020*, p. 14.

are not proposing to change the way scenarios are dealt with as contingent projects during the five-year revenue determination period.

We consider guidelines would be required to create a consistent approach to scenario analysis across the DNSPs

Under our proposed approach, DNSPs would consider a range of likely scenarios for their strategic network plans in accordance with the above requirements. However, there would still be a high-level of uncertainty for DNSPs when deciding how best to meet these requirements. For example, what would be considered a likely scenario may be open to interpretation.

Implementing a requirement in the rules for DNSPs to follow guidelines (e.g. forecasting and planning guidelines) would help to address this uncertainty. It would also create a consistent approach in the NEM and provide assurance to stakeholders that DNSPs are implementing our proposed process with the appropriate rigour. We consider that the rules would need to set out principles that the guidelines should meet or factors to be taken into account.

The rules would also clarify which market body would be responsible for producing the guidelines. We consider that there would be benefits from requiring the AER to produce forecasting and planning guidelines. It currently produces similar guidelines for the ISP framework, the forecasting best practice guidelines.[84] As such, it has the relevant expertise to develop and maintain a new set of similar guidelines for distribution network planning. It may also be preferable to draw on the existing forecasting best practice guidelines for our proposed process, rather than requiring new guidelines to be produced to limit regulatory duplication.

We are interested in stakeholder views on the need for forecasting best practice guidelines to standardise DNSP scenarios analysis and forecasting under this policy approach, including the merits of adopting the existing AER forecasting best practice guidelines.

Question 3: Is scenario analysis the most effective approach for addressing the uncertainty in a long planning horizon?

Do you agree with our proposed requirement for DNSPs to adopt scenario analysis for the proposed strategic planning process under policy option 1?

What do you consider would be the benefits of using scenario analysis and the potential issues?

Would requiring scenario analysis improve the transparency of DNSP strategic planning?

Do you agree with the proposal for DNSPs to develop their scenarios in accordance with AER guidelines? If not, what would be the difficulties with this approach?

What would be the benefits of requiring DNSPs to instead follow the AER's existing forecasting best practice guidelines? What would be the issues with this approach, noting that the guidelines are currently produced for AEMO's ISP process?

DNSPs would be required to adopt AEMO's IASR as baseline inputs for the proposed strategic planning process

We propose to require DNSPs to adopt the relative inputs, assumptions and scenarios from AEMO's Inputs, Assumptions and Scenarios Report (IASR) as baseline inputs for the proposed strategic planning process under policy option 1. We have adopted this proposal to help address concerns that DNSPs are not planning for a future that is consistent with the ISP (section 2.1.3).

84 AER, Forecasting Best Practice, accessed 6 October 2025.

At the same time, we acknowledge stakeholder feedback that the scenarios used for the ISP will not fully align with the scenarios for distribution network planning. In particular, that they are not granular enough to accommodate the types of local considerations required.[85] We also acknowledge that there may not be suitable scenarios for some DNSPs.[86]

As such, we consider that the IASR would only be the starting point for DNSPs when developing their scenarios, assumptions and inputs for their own models. DNSPs would have the flexibility under our proposed process to develop local, granular scenarios and assumptions as needed. However, this would have to be declared and justified in their strategic plans to ensure transparency of the planning process is maintained.

We are interested in understanding if stakeholders consider our proposed approach has sufficiently addressed the concerns with aligning DNSP planning to the ISP. In particular, whether it is sufficiently flexible and transparent to allow DNSPs to effectively plan their distribution networks.

Question 4: Does the IASR provide the right baseline inputs for the proposed strategic planning process under policy option 1?

Do you agree with our proposal to require DNSPs to use the IASR as baseline inputs for the strategic planning process?

What do you consider are the benefits of this approach? Are there any limitations that need to be addressed?

Is there sufficient flexibility in the proposed process for DNSPs to reflect local, granular requirements when preparing their strategic plans? If not, how can greater flexibility be provided, and what would be the costs and benefits?

Do you agree that DNSPs should be required to declare and justify when they adopt different inputs, scenarios and assumptions than the IASR?

Is oversight of these declarations needed? How could this be achieved, and what would be the costs and benefits of requiring greater oversight?

Under policy option 1 the strategic planning process would have a clear line of sight to the regulatory proposal process

As noted above, we consider there are benefits from the strategic planning process being able to draw on and inform the regulatory proposals. It would allow DNSPs to draw on a body of existing work that is resource and time intensive to prepare and consult on, and already rigorously reviewed by the AER. It would also create a clear line of sight in the rules between the network plans DNSPs are required to develop and their regulatory proposal.

We recognise that the regulatory proposal and determination will always inform the capital projects that a DNSP decides to progress for the forward five-year period, with implications for the future state of the network. At the same time, we expect DNSPs capital plans are also informed by their long-term projections for their networks. While project lead times may not be as long as for transmission assets, DNSPs would still be considering if their capital projects will remain fit for purpose over the life of the new assets in the context of load growth scenarios, foreseeable network developments and asset retirements.

85 Australian Energy Market Operator, submission to the consultation paper, p 2.

86 Evoenergy submission to the consultation paper, p3

As such we propose to require DNSPs to commence their strategic plan at the same time as they begin work on their regulatory proposal. It would draw on the regulatory proposal for the first five years of the planning period, while creating a level of consistency across the remaining 15-year period. The strategic plan would then be submitted as part of the regulatory proposal and could act as supporting evidence for the DNSP's proposed capital plan.

The strategic plan would also be refreshed every five years, so that an updated strategic plan is prepared with the next regulatory proposal. We also propose that the strategic plan be updated once the AER has made its determination. This would help ensure that the strategic plan:

- reflects any changes the DNSP makes to its capital plans as a result of the regulatory outcomes for capital expenditure, including approved contingent projects
- is updated over its five-year lifespan so that it remains relevant.

Our proposed approach would require DNSPs to align their scenarios with the regulatory proposals

We consider that, under policy option 1, the DNSPs should be required to produce scenarios for their strategic plans that are consistent with their regulatory proposals. The regulatory proposal and subsequent AER determination provide a strong indicator of the capital expenditure for the next 5 years. As such, a DNSP's capital plan, including contingent projects, should be reflected in the scenarios that are used for strategic planning. This would help to reduce the uncertainty in the near term while ensuring alignment between the regulatory proposals and long-term planning.

We also consider that aligning the strategic plan with the regulatory proposal will help remove a level of duplication that may otherwise be created. The regulatory proposals DNSPs develop are detailed and rigorously reviewed. It would be inefficient to ignore this information, and we expect DNSPs would naturally want to draw on it when planning their networks.

Our proposed approach would draw on existing stakeholder engagement requirements in Chapter 6 of the NER

An additional benefit of linking the strategic planning process to the regulatory proposal process is the ability to draw on DNSPs' existing consultation processes. DNSPs provided evidence in their submissions of the robustness of these processes, including the wide range of stakeholders that they consult.[87] We consider under policy option 1 that the strategic planning process would benefit from similar robust consultations to ensure the plans not only consider engineering and economic requirements, but also community preferences. We also consider that this approach will help address some stakeholder concerns that creating a new, robust consultation process would impose costs on stakeholders and increase stakeholder fatigue with limited potential benefits.[88]

While we note that some stakeholders raised concerns with the outcomes of stakeholder engagement, it is unlikely that implementing a new process would address this issue.[89] However, we are interested in better understanding stakeholder concerns. In particular, whether there are issues with the current stakeholder engagement processes, including in Chapter 6 of the NER, that are leading to these issues. We are also seeking feedback on our proposal for DNSPs to use their existing consultation process for strategic planning under policy option 1.

87 See for example, Jemena submission to the consultation paper, p. 3; CitiPower, Powercor and United Energy submission to the consultation paper, pp. 5-6; Ergon Energy Network and Energex submission to the consultation paper, p. 20; TasNetworks submission to the consultation paper, p. 2.

88 See for example, Jemena submission to the consultation paper, p. 3; Justice and Equity Centre submission to the consultation paper, pp. 7-8.

89 See for example Justice and Equity Centre, submission to the consultation paper, pp. 7-8; Coalition for Community Energy and Changing Weather submission to the consultation paper, p. 1; Clean Energy Council, submission to the consultation paper, p. 6; SA Power Networks submission to the consultation paper, p. 5.

Our proposed approach is intended to incentivise best practice distribution planning

We acknowledged in chapter 2 that some DNSPs are publishing their strategic planning activities already. This can include submitting it to the AER as part of their regulatory proposals. Our intent under policy option 1 is not to add additional regulatory burden on DNSPs for these activities. Rather, it is to incentivise best practice strategic distribution planning by all DNSPs.

While the process outlined above may appear extensive, it is broadly consistent with our planning processes, such as the ISP. We consider that this is necessary to ensure that the NER continues to create an appropriate benchmark for strategic distribution planning in the NEM. However, this would not preclude DNSPs from exceeding this standard. We also anticipate it would be aligned with the approach many DNSPs are already taking.

Creating a clear line of sight between the proposed strategic planning process and regulatory proposal process is also consistent with the existing practice of some DNSPs. While it may seem to make the process AER (rather than consumer) facing, we consider that this is not a material risk. DNSPs would need to engage extensively with their stakeholders both when developing their strategic plans and when developing their revenue proposals. This means that they must be able to communicate their past and proposed plans effectively to a wide range of audiences.

Question 5: Should the proposed strategic planning process be linked to the regulatory proposal process in Chapter 6 of the NER under policy option 1?

Do you agree that the proposed strategic planning process should draw on and inform the regulatory proposals that DNSPs already prepare?

What do you consider are the advantages and disadvantages of this approach? Would it be possible to address the disadvantages in our proposed process?

Do you agree with our proposal to require the proposed strategic planning process to be consistent with a DNSP's regulatory proposal, including its capital plans? What do you consider are the benefits and challenges of this approach?

Should the proposed strategic planning process use the existing consultation requirements in Chapter 6 of the NER? What do you consider are the advantages and disadvantages of this approach?

Are there others parts of the regulatory proposal process that the proposed strategic planning process should be linked to? What would be the advantages and disadvantages of creating further links than already proposed?

3.1.2 Our proposed reforms to the distribution annual planning process

We are proposing to retain the existing distribution annual planning process under our preferred policy approach. Under this approach, the distribution annual planning process would have a distinct purpose from the strategic planning process to minimise any potential overlap and clarify its role in the broader planning framework. We consider that its purpose would be to provide information to stakeholders on the current state of the DNSP's distribution network and expected near-term constraints. This information would be more detailed and accurate than is possible under the strategic plan and could be used for different purposes, most notably to assist with connection requests and identify potential opportunities for non-network options.

However, we note that multiple stakeholders provided feedback that the current planning process does not currently meet these goals and in particular, that it is not leading to the procurement of non-network options (chapter 2). As such, we are proposing under policy option 1 to reform the

distribution annual planning process to ensure it remains fit for purpose, while limiting the potential duplication with the strategic planning process. We are proposing to achieve this by:

- establishing the purpose of the distribution annual planning process in the NER
- streamlining the distribution annual planning report so that it is focused on reporting planning outcomes
- requiring DNSPs to separately report on many of the data elements from the current DAPR
- requiring DNSPs to provide greater visibility of the low-voltage network.

This section provides more information on each of these proposed changes and seeks stakeholder feedback.

We propose under policy option 1 to clarify the purpose of the distribution annual planning process in the rules

As noted above, we consider that the distribution annual planning process has a clear purpose in our proposed planning framework under policy option 1. However, the distribution annual planning process does not currently have its purpose established in the rules. This means that different stakeholders may have different interpretations of the purpose of the process, which then informs how they evaluate its performance and proposed solutions. For example, an IDSP process may lead to more robust network planning, but may be too onerous for providing transparency on the current and near term constraints of a network.

Setting a clear purpose for the distribution annual planning process in the rules would create a shared understanding of the intent of the process amongst all stakeholders. We are proposing the following framing for the purpose under policy option 1:

To inform stakeholders of the current state of a DNSP's distribution network and the expected near-term changes.

This purpose makes it clear that the distribution annual planning process has a distinct role from the proposed strategic planning process under our preferred approach (policy option 1). It is also consistent with the intent of the DAPR that SA Power Networks submitted.[90] We note that we have avoided including how the information is to be used in the purpose as we do not want to limit the potential use cases. It is possible that the distribution annual planning process may be used by stakeholders in different ways in future.

We are seeking stakeholder feedback on our proposed purpose for the distribution annual planning process under policy option 1. When responding, we ask stakeholders to consider how the distribution annual planning process fits within the broader planning framework including with the regulatory proposal process set out in rule 6.8 of the NER.

Question 6: Does the distribution annual planning process require an explicit purpose in the rules under policy option 1?

Do you agree that it would be beneficial to articulate the purpose of the distribution planning process in the rules under our preferred policy option?

Do you consider that the proposed purpose helps clarify how the distribution annual planning process fits into the broader planning framework in policy option 1?

Do you agree with our proposed purpose? If not, what should be the purpose of the distribution

90 SA Power Networks submission to the consultation paper, p 2.

annual planning process under our proposed policy option 1?

We are proposing in policy option 1 to streamline the current distribution annual planning report

The outcomes of the distribution annual planning process are currently reported on in the distribution annual planning report. While rule 5.13 of the NER establishes the reporting mechanism, the detailed requirements for the DAPR are set out in Schedule 5.8. These requirements are quite detailed and prescriptive. We acknowledge stakeholder feedback that many of these requirements may no longer be as relevant (section 2.2). For example, forecast load limits may be more beneficial if they are reported on in a dynamic format that is regularly updated every 3 months.

We propose to address this under policy option 1 by focusing the DAPR on reporting annual planning outcomes and removing much of the network data from the report. The DAPR would continue to provide a central location for reporting on joint planning outcomes and RIT-D projects. It would also continue to provide transparency on the expected state of the distribution networks over the forward five-year planning period. We expect this information will still be needed by stakeholders even with the separate reporting of network data (see below). For example, for a commercial business planning an expansion or new connection to check if an existing network constraint will be addressed before submitting a formal connection request.

We are seeking stakeholder views on whether this is the right approach for the DAPR under policy option 1 and if other information should be retained or removed. In responding to the questions below, we ask that you consider the separate reporting requirements that we are also proposing to establish for network data in policy option 1 (see below).

Question 7: Does the distribution annual planning report need to be streamlined under our proposed policy option 1?

Do you agree with our proposal in policy option 1 for the DAPR to focus on reporting planning outcomes and not also report on network data (noting our proposal for separate network data reporting obligations)?

If so, what planning outcomes should be captured by the DAPR? Would it be sufficient to capture the outcomes of the annual planning review as well as the existing reporting requirements for RIT-D projects and joint planning in Schedule 5.8 of the rules? Are there any other planning outcomes that also need to be captured in the DAPR?

Is there other information that should also continue to be reported in the DAPR in policy option 1, noting that we are not proposing to make the report more dynamic?

We propose to implement separate reporting requirements for distribution network data

We acknowledge that DNSPs have already begun making changes to the way they report network data in response to stakeholder feedback. However, this is not currently reflected in the rules and there remains a high likelihood that the DNSPs will each adopt a different approach, making it difficult for stakeholders to compare and use data across the DNSPs. This is not only relevant for businesses working across state and territory borders, but also within the same jurisdiction. We also acknowledge that there are other processes that will also inform the approach to network data and reporting, such as the workstreams and national reform priorities under the national CER

roadmap (section 3.5). We have considered these factors when deciding how best to enable improvements in network data and its reporting, to address stakeholder concerns (section 2.2).

Our current position is that appropriate, up to date and consistent data can best be determined through an AER guideline, such as a network data reporting guideline. Under our proposed approach, the rules would establish an obligation on the DNSPs to publish network data in accordance with the guideline. The rules would not stipulate what data is to be published or captured in the guidelines, or the format of that data, so as not to preempt any changes in the DNSPs' data capabilities. This would be left to the AER determine, in accordance with principles for the guidelines that would also be established in the rules. We envisage that the AER would strengthen the guideline requirements as DNSPs' data capabilities improve, and would also evolve the requirements in line with stakeholder needs.

We currently anticipate the principles would require the AER to consider:

- the consumer benefit of requiring DNSPs to publish particular data types or data sets
- whether the consumer benefit is sufficient to offset the cost to DNSPs publishing the data
- the feasibility of collecting and publishing the data in the proposed format
- the potential use cases for the data
- differences in DNSP data capabilities, and how this can be managed (e.g. transition periods for some DNSPs)
- feedback provided by stakeholders during the consultation period.

We consider that these principles would allow the AER to make guidelines that support ongoing improvements in network data publication and transparency. The principles would also acknowledge that DNSPs incur costs collecting and publishing data, so that any data published should be useful and provide a net benefit. We anticipate that the principles would provide the AER with the flexibility needed to draw on data sets from existing and future processes, such as the AER's existing performance monitoring and reporting,[91] and the proposed CER data exchange,[92] without having to duplicate them. These data sets will have established use cases and including them in any potential guideline would reduce duplication and reporting costs for DNSPs.

We are interested in stakeholder feedback on our proposed network data reporting requirements, including our proposed principles for the AER. In responding we ask stakeholders to consider the need for flexibility so that any reforms made as part of this rule change process can seamlessly integrate with the potential future outcomes of other processes examining network data. For example, the CER data exchange that AEMO is currently progressing[93] and any recommendations that will result from the *Data Sharing Arrangements - M2* project of the national CER roadmap.[94]

Our proposed approach would also improve visibility of the low-voltage network

We consider that there is no need to separately address the issue of low-voltage network visibility. Our proposed approach will provide the AER with the flexibility to adjust the network data reporting guidelines as DNSPs' capability improves. It could also be used as a mechanism to drive DNSPs to improve their data capabilities, though this will need to be balanced against the potential costs involved such as expenditure on new back office processes and software development. However, we consider the AER is well-placed to consider these tradeoffs as it currently considers these

91 Further information on the AER performance monitoring is available on the AER website, accessed 3 October 2025.

92 Further information on the CER data exchange proposal is available on AEMO's website, accessed 3 October 2025.

93 More information on the CER data exchange is available on AEMO's website, accessed 3 October 2025.

94 More information on the recent consultations for Data Sharing Arrangements - M2 on the Commonwealth Department of Climate Change, Energy, the Environment and Water's website, accessed 3 October 2025.

types of expenditure during the revenue determination process for DNSPs. We also note that the AER has existing knowledge on the limited visibility of the low-voltage network due to its recent work on low-voltage network visibility and the publication of its phase 3 final report.[95] It will be able to draw on this when preparing our proposed guidelines.

We are interested in understanding whether stakeholders agree with our initial assessment. In particular, whether there is a gap between our proposed approach and the process needed to improve low-voltage network visibility.

Question 8: Does network data need to be subject to a separate reporting requirement from the DAPR?

Do you agree with our proposal for the network data currently reported in the DAPR to be subject to separate reporting requirements?

If so, do you agree that these requirements need to be flexible to accommodate likely changes in data usage and reporting due to other work currently underway (e.g. under the national CER roadmap)?

Would this be best achieved through guidelines, such as the proposed network data and reporting guideline? If not, is an alternative approach needed, and what would be the costs and benefits of this alternative?

Is the AER the appropriate market body to be responsible for developing and maintaining the proposed network data and reporting guideline?

Do the proposed principles for the guidelines strike the right balance between encouraging transparency, innovation in data collection and reporting, and disincentivising improved data capabilities with the costs that data collection and publication create?

Should the AER, or other appropriate market body, be able to gather and report on other data that is not related to network planning? For example, inverter setting compliance that may be available to DNSPs through their CSIP-Aus connections associated with the backstop mechanism rollouts? What would be the costs and benefits of not restricting the guidelines to network data?

3.1.3 We propose that policy option 1 would be implemented over seven years

We anticipate that our proposed reforms under policy option 1 would require a transition period to be implemented. Not only have we proposed establishing a new strategic planning process, albeit we expect it to draw on existing internal planning processes, but also broad changes to the distribution annual planning process. Some of our proposed changes also rely on DNSPs following guidelines to be produced by the AER, or potentially another market body.

Nonetheless, not all of these changes will require the same amount of time to be implemented. We consider that the maximum time needed to implement policy option 1 would be seven years so that all DNSPs can prepare their strategic plans with their next regulatory proposals. However, we anticipate other elements could be implemented sooner, such as changes to the reporting requirements for the DAPR.

As such, we are proposing a seven year, staged transition be adopted:

1. 1 year: DNSPs to meet new publication requirements (section 3.1.2).
2. 1-2 years: DNSPs to meet new network data reporting requirements (section 3.1.2), subsequent to the AER publishing data reporting guidelines.

95 AER, Network visibility, accessed 9 October.

3. 1-2 years: the AER to prepare best practice forecasting guidelines for distribution network strategic planning
4. 2-5 years: DNSPs to have prepared likely scenarios in accordance with the AER guidelines
5. 5-7 years: DNSPs to have submitted their strategic plans with their revenue proposals
6. End of 7 years: DNSPs to be fully compliant with all requirements.

This would be supported by requiring each DNSP to produce an implementation plan. The plan would require DNSPs to outline how they will prepare for each of the implementation stages. DNSPs would then update the plan each year to demonstrate how they have progressed and will meet future stages. This will provide transparency to stakeholders on each DNSPs implementation plan and their progress to date.

We are interested in stakeholder views on our proposed implementation approach for policy option 1 and in particular, whether it strikes the right balance between supporting DNSPs to implement the changes at least-cost to consumers.

Question 9: Do you agree our proposed policy option 1 would best be implemented over seven years?

Do you agree that our proposed reforms would need to be implemented in stages? If not, what do you consider to be a better implementation path?

Do you consider that our proposed implementation stages for policy option 1 would likely be met? If not, what timeframes are needed? Would an alternative transition period be needed?

Do you support our proposal for DNSPs to produce an implementation plan under policy option 1? What do you consider are the advantages and disadvantages of this approach?

3.2 Policy option 2 - reforming the existing distribution annual planning process without implementing a new planning process.

We acknowledge that our current preferred policy approach to create two distribution planning processes would have associated implementation challenges. It will take time to fully implement and would likely impose a greater regulatory burden (albeit we expect these costs would be offset by the likely benefits of improving the rigour of distribution planning in the rules). These challenges led us to also consider the merits of amending the existing distribution annual planning process without implementing a strategic planning process, i.e. our second proposed policy option.

This section provides more details, for stakeholder consultation, on how the distribution annual planning process could be reformed to establish a more rigorous strategic planning approach. It provides:

- an overview of the proposed reforms to the distribution annual planning process (section 3.2.1)
- the potential advantages of this approach over the other policy options (section 3.2.2)
- the potential disadvantages of this approach compared to the other policy options (section 3.2.3)
- an initial assessment of how this policy option aligns with our assessment criteria (section 3.2.4).

3.2.1 We consider that many of our proposed reforms to the distribution annual planning process in policy option 1 are still required for policy option 2

Under this proposed approach we would not tie the existing annual planning process to the regulatory proposals that DNSPs prepare. We consider the proposed data reporting reforms outlined in section 3.1.2 would still be needed to improve the distribution annual planning process. In particular, making data more relevant and moving data reporting in a more accessible and dynamic format would remain relevant.

However, the above changes do not address the gap in strategic planning stakeholders have raised (section 2.1.1). We consider further changes would be needed to address this gap if a strategic planning process is not implemented, namely:

- adopting a new minimum planning horizon (either 10, 15 or 20 years)
- clarifying the purpose of the distribution annual planning process to reflect its role as the strategic planning process
- changes to stakeholder engagement requirements, to explicitly require DNSPs to draw on stakeholder input from other NER processes (notably the consultation requirements in Chapter 6 of the rules).

We note that DNSPs provided mixed views on the benefits of adopting a longer planning horizon for the distribution annual planning process. While some highlighted that the current minimum remains appropriate,[96] others were supportive of a longer planning horizon.[97] We consider that a 10-year planning horizon would be most effective for policy option 2 as it:

- Creates alignment between the distribution and transmission planning processes in the NER.
- Reduces duplication for DNSPs that already adopt a 10-year planning horizon when planning their transmission assets or engaging in joint planning.
- Would be more certain than a 20-year planning horizon, reducing the need for multiple scenarios and more robust planning processes which may be difficult to implement in an annual process.

We also consider that there is merit in clarifying the purpose of the distribution annual planning process. It is not currently clear that stakeholders agree on what the purpose of the distribution annual planning process should be. For example, Energy Consumers Australia notes that one benefit of reforming distribution planning would be the cost-effective integration of CER and increased electrification to avoid unnecessary future distribution network costs.[98] It further notes that:

... the lack of frequent, comprehensive and transparent planning and data creates information asymmetries between DNSPs and third-party participants, hindering CER uptake and resulting in less optimal outcomes for consumers.[99]

In comparison, SA Power Networks consider that:

The intent of the DAPR is to provide industry with clear information on current and forecast constraints on the distribution network to inform efficient location of new connections, as well as where opportunities may exist to support efficient network management through the supply of non-network solutions.[100]

96 See for example Ergon Energy Network and Energex submission to the consultation paper, p 4; Tasnetworks submission to the consultation paper, p 3.
97 See for example Ausnet submission to the consultation paper, p 4; Citipower submission to the consultation paper, p 4.
98 Energy Consumers Australia submission to consultation paper, p 1.
99 Energy Consumers Australia submission to consultation paper, p 1.
100 SA Power Networks submission to the consultation paper, p 2.

Given this, we propose that the following purpose would be adopted for the distribution annual planning process under policy option 2:

To require DNSPs to plan efficient investment in those electricity network services that maximise the long term interests of consumers under a credible range of scenarios.

We note that this is the proposed purpose for the strategic planning process in policy option 1, and reflects the different role of the distribution annual planning process under policy option 2.

We would also propose a new requirement for DNSPs to draw on stakeholder input from other processes. We acknowledge that some DNSPs submitted that they have robust consultation processes due to the requirements under Chapter 6 of the NER.[101] However, this is not reflected in the current planning process. We consider that this should be addressed under policy option 2 to assure stakeholders that DNSPs are drawing on this input when preparing their annual plans. This would be an additional requirement and would not replace the existing industry engagement process.

Question 10: Can the current distribution annual planning process be reformed to effectively deliver strategic planning and transparency?

Do you consider that the distribution annual planning process can be reformed to provide both strategic planning and transparency of the current and near term state of distribution networks?

If so, what changes are needed? Have they all been captured by our proposed reforms to:

- implement separate network data reporting requirements
- amend the planning horizon to 10 years
- clarify the purpose of the distribution annual planning process
- amend the existing stakeholder engagement obligation to explicitly require DNSPs to draw on stakeholder input from other NER processes.

Are there any additional reforms that would be needed to ensure that the distribution annual planning process would deliver strategic planning and transparency?

Do you agree that a 10-year planning horizon would be more effective in supporting long term strategic planning for policy option 2? If not, what do you consider are the advantages and disadvantages of a 10-year planning horizon?

Would a 20-year planning horizon be more effective, as proposed for policy options 1 and 3? What do you consider would be the advantages and disadvantages of this longer planning horizon under policy option 2?

3.2.2 Policy option 2 would result in fewer changes and be quicker to implement in full

We consider that policy option 2 would be quicker to implement than either our preferred approach (policy option 1) or policy option 3. It would result in less significant changes to distribution planning in the NER, reducing implementation costs. It would also still streamline the DAPR while improving the quality and transparency of data reporting by DNSPs. As such, we do not consider a 7-year staged implementation would be needed. Instead, we anticipate all the changes could be implemented by the end of 2-3 years, subject to the AER developing new network data reporting guidelines.

101 Ausgrid submission to the consultation paper, p. 8; Ergon Energy Network and Energex submission to the consultation paper, p. 20.

We acknowledge that DNSPs will need to undertake further work beyond the 2-3 years, depending on how the network data reporting requirements (section 3.1.2) evolve over time. However, we do not consider it is necessary to capture this in the transition period. We consider it is important to be clear when the changes to the distribution annual planning process should be completed so that the benefits of the reforms can commence as quickly as possible. Our proposed network data reporting requirements are intended to be evolutionary so that they can continue to reflect changes in DNSPs' capabilities and data use cases. As such, we do not anticipate that there will be a clear end date for this work, and that this will need to be managed by the DNSPs and the AER accordingly.

We note that we would also expect that the regulatory burden of policy option 2 would be lower than the other policy options we have proposed. It does not result in as significant changes from the status quo than either policy option 1 or 3 and does not result in two planning processes as we have proposed in policy option 1. However, we also do not expect that policy option 2 would necessarily reduce compliance costs for DNPSs from the current distribution annual planning process.

3.2.3 This alternative approach may reduce transparency on the expected near-term state of distribution networks

While policy option2 would be quicker to implement, as noted above, it would still result in a single planning process. The distribution annual planning process would now be used to both transparently share information on the expected near-term state of the distribution network and transparently share information on DNSPs' strategic plans.

For example, the change in planning horizon to address the gap in strategic planning may result in the distribution planning process providing less precise information on the near state of distribution networks. The 10-year planning horizon may limit the ability of DNSPs to provide a more certain, granular outlook across their network. While some of our other proposed changes may address this gap for CER investors, particularly changes to reporting on network capacity, we note that there may also be less transparency.[102] The 10-year planning horizon may also not be long enough to facilitate proactive strategic planning, which many stakeholders expressed as a concern with the existing process (section 2.1.1). Alternatively, adopting a 20-year planning horizon or scenario analysis may be sufficient to address these issues. However, as noted above, a 20-year planning horizon would be less certain, and it is currently unclear if the level of rigour needed for the scenarios could be repeated regularly in an annual cycle.

Perhaps, more importantly, there would be a potential loss of synergy with the revenue determination process, including clarifying how the annual planning process fits within the broader planning framework. The revenue determination process requires extensive resourcing from DNSPs to undertake rigorous consultation, forecasting and planning. These elements are also needed in the annual planning process, creating a real risk of duplication between the two processes. The consultation, forecasting and planning undertaken for the revenue determination is also reviewed and ultimately informs the capital expenditure for the proceeding five years.

We note that we are still considering how this alternative will interact with the Victorian Electricity Distribution Code of Practice (the Code), as it will depend on the extent of changes to the distribution annual planning process.[103] Currently, the Code's requirements are similar to the

102 See for example Ergon Energy Network and Energex submission to the consultation paper, pp. 3-4.

103 The Victorian Electricity Distribution Code of Practice requires Victorian DNSPs to prepare a distribution system planning report with a five-year planning horizon (clause 19.4 of the Code). This is broadly similar to the distribution annual planning report though there are some differences, such as requiring Victorian DNSPs to detail how they are using advanced metering infrastructure technology.

distribution annual planning process. However, some of the proposed changes under this alternative, most notably the 10-year planning horizon, would create differences that may prevent Victorian DNSPs from satisfying both the process and the Code in one report. We will consider this issue further if stakeholders strongly support this alternative approach over the other proposed policy approaches.

We are interested in understanding if stakeholders agree with our assessment of the advantages and disadvantages of only reforming the distribution annual planning process. We would also like to understand if stakeholders consider that the distinct purposes of strategic planning and annual planning can be achieved in a reformed annual planning process. In responding, we ask stakeholders to consider how the distribution annual planning process would be reformed, including the proposed changes to network data reporting and the planning horizon.

Question 11: Have all the advantages and disadvantages of reforming the existing distribution annual planning process under policy option 2 been identified?

Do you agree with our assessment of the potential advantages and disadvantages of our proposed policy option 2?

Do you consider that these potential advantages outweigh the disadvantages of policy option 2, including faster and simpler implementation, and the possibility of duplication with the revenue determination process?

3.2.4 Initial evaluation against our assessment criteria

We consider that this alternative approach, relative to our preferred policy option, would also:

- Equally require DNSPs to improve transparency of their distribution networks and planning processes, and reduce transaction costs for third parties (addressing the principles of market efficiency assessment criterion).
- Be consistent with the broader direction of reform, providing a predictable and stable planning framework, and promote transparency for stakeholders (addressing the principles of good regulatory practice assessment criterion).
- Be less costly and complex to implement and administer for DNSPs, the market bodies and market participants (addressing the implementation considerations assessment criterion).
- Lead to the more timely realisation of benefits from the reformed planning process as it will be quicker to implement this alternative (addressing the implementation considerations assessment criterion).

However, it may not as successfully:

- Promote efficient investment in networks in the long-term interest of consumers (addressing the safety, security and reliability assessment criterion) as the reformed distribution annual planning process will not be as clearly aligned with the broader planning framework as our proposed strategic planning process.
- Help build trust and social licence as it may not provide as much oversight of the strategic planning DNSPs currently undertake, though it will still create a clear implementation plan that aligns with other reforms (addressing the implementation considerations assessment criterion).

Question 12: Do you agree with our relative assessment of policy option 2 (reforming the distribution annual planning process) against policy option 1 (reforming the existing annual process and implementing a strategic planning process)?

Do you agree that we have captured the material relative advantages and disadvantages of this alternative approach against our preferred approach?

If not, what do you think needs to be included in our assessment of policy option 2 against our assessment criteria? Would this change the overall assessment of policy option 2 against our preferred approach, policy option 1?

3.3 Policy option 3 - implementing the proposed strategic planning process while removing the distribution annual planning process

Under our final proposed policy option, we considered the merits of replacing the existing distribution annual planning process with our proposed strategic distribution planning process. We are aware that some stakeholders provided support for the IDSP process and saw merit in requiring greater strategic planning of distribution networks under the rules. While this could be achieved by reforming the distribution annual planning process as outlined in policy option 2, we considered that stakeholders views on its limitations and the support for the IDSP process warranted exploring the creation of a dedicated strategic planning process.

This section provides more details, for stakeholder consultation, on how a strategic planning process could be implemented in order to replace the current distribution annual planning process. It provides:

- an overview of the option (section 3.3.1)
- the potential advantages of this approach over the other policy options (section 3.3.2)
- the potential disadvantages of this approach compared to the other policy options (section 3.2.3)
- an initial assessment of how this option aligns with our assessment criteria (section 3.3.4).

3.3.1 Replacing the current distribution annual planning process with our proposed strategic distribution planning process would require some reporting changes

Under this policy option, the strategic planning process we outlined in policy option 1 (section 3.1.1) would be implemented in the rules to replace the existing distribution annual planning process. The new strategic distribution planning process would still be tied to the regulatory proposal process and have its own reporting requirements. As such, the DAPR and its supporting requirements in the rules would no longer exist.

We anticipate that this change will create a gap in reporting that will reduce transparency unless addressed. We propose to partly address this gap by implementing our proposed reforms to network data reporting. In particular, that the collection and publication of network data would still be reported on independently of the proposed strategic plan, and that these reporting obligations would be managed through guidelines prepared by the AER (section 3.1.2).

However, these changes are not sufficient to fully address the reporting gap. There are elements of the DAPR that would not be captured by the proposed network data reporting requirements and are not suitable for reporting in the strategic plan. For example, the annual summaries of a DNSP's completed and in progress RIT-D projects or of their joint planning. We consider these elements

should still be reported on annually as they provide transparency to stakeholders, particularly on the expected near-term state of the distribution network.

We propose to provide this transparency by requiring DNSPs to annually publish (e.g. on their website):

- a high level summary of completed, progressing and anticipated RIT-D projects for the past and future year
- an overview of the joint planning the DNSP undertook with other DNSPs or TNSPs over the past year
- any changes to planned network projects since the strategic plan or previous year
- any changes in the likelihood of the scenarios that were considered in the DNSP's strategic plan.

We expect that under this approach the rules would provide guidance on how the annual publication would occur. However, we do not have a firm view on this and would welcome stakeholder feedback on how this could be best provided by DNSPs without being an onerous requirement. Potential options include, but are not limited to, reporting on their website or in conjunction with any regulatory information notice that the AER has issued to the DNSP.

3.3.2 Policy option 3 would allow DNSPs and stakeholders to focus on implementing the proposed strategic planning process

We consider that policy option 3 would allow for a stronger focus to be placed on strategic planning than our preferred approach. There would only be one planning process in the rules, allowing DNSPs to focus on implementing the new process. This would also remove the need for DNSPs to dedicate resources to maintaining the distribution annual planning process or the DAPR (albeit with more streamlined reporting). As such, we expect that the ongoing administrative burden of policy option 3 would be lower than policy option 1.

Policy option 3 also reduces the likelihood of duplication in reporting as DNSPs would not have to prepare both the DAPR and a strategic plan. This not only reduces reporting costs for DNSPs, but also clearly indicates to stakeholders that the strategic plan would be the central distribution network planning process in the rules. The strategic plan would also continue to be linked to the regulatory proposal process, providing greater clarity on how the distribution planning process could relate to a DNSP's regulatory proposal.

3.3.3 Policy option 3 may reduce transparency of the near term state of distribution networks

We consider that the reporting and administrative cost benefits of policy option 3 outlined above may be tempered for Victorian DNSPs. We expect that they would still need to produce an annual planning report even if the DAPR is removed, due to the requirements of the Victorian Electricity Distribution Code of Practice. As such, there would also be some inconsistency between the specific jurisdictional planning requirements in Victoria and the broader NEM.

We also acknowledge that the removal of the DAPR under policy option 3 may reduce transparency on the near-term state of distribution networks. While the strategic plan would provide similar insights into the forward five-year period as the revenue determination, it would not be updated every year. We also expect that the strategic plan would not be at the same granular level as the DAPR. However, we expect maintaining the proposed network data reporting requirements would ensure ongoing transparency of the current state of the distribution network even without a DAPR.

Removing the distribution annual planning process would also remove the industry engagement obligations for non-network options. While similar obligations could be included in the strategic planning process, it would be as part of the proposed five-yearly planning cycle. As such, there would be less annual engagement than under the current distribution annual planning process. This could potentially lead to fewer non-network options being proposed, particularly if a proposed network solution does not fall within the requirements of the RIT-D process. There is therefore a potential case for incorporating an industry engagement process for non-network options in the strategic planning process should stakeholders prefer policy option 3.

Question 13: Have all the advantages and disadvantages of replacing the existing distribution annual planning process with the proposed strategic planning process under policy option 3 been identified?

Do you agree with our assessment of the potential advantages and disadvantages of our proposed policy option 3?

Do you consider that these potential advantages outweigh the disadvantages of policy option 3, including greater focus on strategic planning and the possibility of reduced transparency on the expected near-term state of distribution networks?

3.3.4 Initial evaluation against our assessment criteria

We consider that policy option 3, relative to our preferred policy option 1, would also:

- Promote efficient investment in networks in the long-term interest of consumers (addressing the safety, security and reliability assessment criterion).
- Require DNSPs to improve transparency of their distribution networks and planning processes, and reduce transaction costs for third parties (addressing the principles of market efficiency assessment criterion).
- Help build trust and social licence by improving oversight of how DNSPs strategically plan their networks, while also creating a clear implementation plan that aligns with other reforms (addressing the implementation considerations assessment criterion).
- Be consistent with the broader direction of reform, providing a predictable and stable planning framework, and promote transparency for stakeholders (addressing the principles of good regulatory practice assessment criterion).

We also consider that this policy option would be less complex to implement than and impose lower ongoing regulatory costs as there would only be one planning process in the rules (addressing implementation considerations assessment criterion).

However, it may reduce transparency over the current and expected near-term state of distribution networks as the DAPR would no longer exist (addressing safety, security, and reliability and principles of market efficiency assessment criteria). The potential removal of the industry engagement process would also reduce the availability of non-network option proposals for DNSPs to consider, reducing dynamic and allocative efficiency in distribution network investment and planning (addressing principles of market efficiency).

Question 14: Do you agree with our relative assessment of policy option 3 (replacing the distribution annual planning process with the proposed strategic planning process) against policy option 1 (reforming the existing annual process and implementing a strategic planning process)?

Do you agree that we have captured the material relative advantages and disadvantages of policy option 3 against policy option 1?

If not, what do you think needs to be included in our assessment of policy option 3 against our assessment criteria? Would this change the overall assessment of policy option 3 against policy option 1?

3.4 We are seeking broad stakeholder feedback on our proposed policy options

We have outlined our proposed policy options in detail above and have sought targeted feedback on each of their proposed processes and relative advantages and disadvantages. We are also seeking broader feedback from stakeholders on all three policy options. For example, whether our proposed policy options would support best practice distribution network planning by the DNSPs or if another policy approach than the ones in this directions paper (including the appendices) is needed. As noted at the beginning of this chapter, we also want to understand whether stakeholders strongly support or object to one, or all of our, proposed policy options. This feedback will then help inform the policy positions we adopt for our draft determination and draft rule.

Question 15: Would our proposed policy options create a best practice process for strategic distribution network planning?

Have we captured the key elements of strategic distribution network planning and do these reflect best practice? Do these three proposed policy options represent the broad spectrum of options that the Commission should consider?

Do you consider that each of our proposed policy options are likely to be workable in the NEM? Are there any additional models that we should consider, including a hybrid of some of the proposed policy options?

Is there a proposed policy option you strongly support? Which feature(s) of this policy option do you consider are particularly effective? Is there a feature(s) of this option that you consider is problematic and why?

Is there a policy option that you consider is unlikely to be workable in the NEM? Which feature(s) of this policy option do you consider are particularly problematic and why?

Is there a proposed policy option you strongly disagree with? Which feature(s) of this policy option do you consider are particularly problematic and why? Are there any feature(s) of this policy option that you consider would be effective and why?

3.5 We have considered how our proposed approach aligns with the broader reforms currently being considered

We are mindful of the number of other work programs currently being progressed that are also considering network data and distribution planning. We consider that it is critical that any changes made as part of this rule change process are consistent with the broader direction of these reforms. This is not only needed to meet our assessment criteria, particularly the principles of good regulatory practice, but also to reduce the regulatory cost of any reforms while ensuring they can be successfully implemented.

The main programs of work we have considered when developing our policy options are:

- the national CER roadmap projects, including:
  - *Data Sharing Arrangements – M2*
  - *CER data exchange – M2*
  - *Redefine roles for market and power system operations – M3/P5*
- *The pricing review: Electricity pricing for a consumer-driven future.*

This section outlines, for stakeholder consultation, how we consider our policy options align with each of the above projects. It sets out:

- how our proposed network data reporting reforms would interact with the potential outcomes of the *Data Sharing Arrangements – M2* and *CER data exchange – M2* projects (section 3.5.1)
- the potential for our proposed policy options to support the *Redefine roles for market and power system operations – M3/P5 project* (section 3.5.2)
- how our proposed policy options could support more dynamic network pricing approaches that are being considered in our *The pricing review: Electricity pricing for a consumer-driven future (*section 3.5.3*)*

We note that this section reflects an initial assessment based on the current phase of each of these projects, including this rule change process. However, the *Data Sharing Arrangements – M2* and *Redefine roles for market and power system operations – M3/P5* projects are currently on track to provide recommendations for the Energy and Climate Change Ministerial Council (ECMC) to consider by end of 2025.[104] We will reflect the outcomes of these projects, including any decisions by the ECMC, for our draft determination that will be published in March 2026.

3.5.1 Our proposed network data reporting requirements would be sufficiently flexible to accommodate the outcomes of the national CER roadmap projects

We are proposing to implement new network data reporting requirements as part of all three proposed policy options. As outlined in section 3.1.2, we have considered how the proposed reporting requirements would interact with the recommendations of the national CER roadmap projects. This informed our approach to the reporting requirements, including proposing that they would be implemented through network data reporting guidelines that would be developed by the AER.

Our view is that the guidelines would be more flexible than prescribing the reporting requirements in the rules. The AER would be able to update the guidelines as it deems appropriate, without requiring a rule change request to instigate any change. This provides our proposed reporting requirements with flexibility to be updated as significant milestones in the national CER roadmap projects are achieved, such as the next phase of the CER data exchange. We note that the AER

104 National CER Roadmap Implementation Plan Update, August 2025, pp. 27-30

would also have the benefit of the recommendations from the *Data Sharing Arrangements – M2* project when preparing our proposed guidelines. We consider that the earliest anticipated implementation of our proposed guidelines by the AER would be the second half of 2026, which is well after the *Data Sharing Arrangements* project is expected to report to the ECMC.[105]

We note that several stakeholders raised the potential for our proposed reforms to contradict or address the same issues being considered by the *Data Sharing Arrangements - M2* project. We would like to understand if stakeholders agree that our proposed policy options would address these concerns and if not, what changes to our policy options would be needed.

3.5.2 Our proposed planning reforms would enhance long-term distribution network planning under the rules

The *Redefine roles for market and power system operations – M3/P5* has identified long-term planning as an essential function of Distribution System Operators. For example, it is noted in the Consultation Paper to progress M3/P5 workstreams of the National CER Roadmap that:

Integrated Distribution Planning: Perform long-term distribution system planning, in consultation with the system operator (AEMO in the NEM) and relevant transmission network, as an integral part of advanced whole-system planning. CER growth scenarios play an integral role in ensuring the necessary system capacity and capabilities are in place, conventional network and non-network solutions are equally considered, and beneficial system services are sourced from CER where more efficient. [106]

The Consultation Paper also states that:

We need to accurately account for CER in our planning and operating frameworks and harness CER to help balance supply and demand, manage congestion and contribute to system security. [107]

While our proposed policy options do not go as far as integrated distribution planning, they would improve the quality of long-term distribution planning in the regulatory planning process established in the rules. We expect that our proposed network data reporting requirements would also lead to better quality network information to support DNSPs to account for CER in their planning and operating frameworks. As such, we consider that our policy options are broadly consistent with, and would support the work of, the *Redefine roles for market and power system operations – M3/P5* project.

We are interested in understanding if stakeholders agree with this assessment and if any changes to our policy options would be needed.

Our proposed planning reforms would also be consistent with the recommendations of the NSW transmission planning review interim report

The NSW Government commissioned a review of transmission planning in NSW in February 2025.[108] This Review was a recommendation of the Electricity Supply and Reliability Check Up report, which identified reform and further work needed to deliver the NSW Electricity Infrastructure Roadmap.[109] The interim report for the NSW transmission planning review made

105 National CER Roadmap Implementation Update, August 2025, p. 27.

106 Department of Climate Change, Energy, the Environment and Water, *Consultation Paper to progress M3/P5 workstreams of the National CER Roadmap*, July 2025, p. 32.

107 Department of Climate Change Energy, the Environment and Water, *Consultation Paper to progress M3/P5 workstreams of the National CER Roadmap*, July 2025, p. vi.

108 NSW transmission planning review, *Interim Report*, 27 June 2025, p. 10.

109 NSW Government Climate and Energy Action website, NSW Transmission Planning Review 2025, accessed 3 October 2025.

several recommendations that are relevant to distribution network planning.[110] For example, draft recommendation B.3:

Expand planning report processes so they are informed by comprehensive information on transmission, distribution and non-network options and can assess their relative benefits.[111]

We consider that our proposed policy options would be consistent with the draft recommendations set out in the Interim Report. They are intended to improve the robustness of distribution planning in the rules, including enabling more rigorous assessments of the relative costs and benefits of non-network options by DNSPs. The proposed changes in distribution network planning and data reporting may also assist in assessing the relative benefits of transmission and distribution options.

We are interested in understanding if stakeholders agree with this assessment and if any changes to our policy options would be needed.

3.5.3 Our proposed network data reporting requirements would support DNSPs to adopt more dynamic network pricing approaches

Our Pricing review is currently considering how retailer offerings and network tariffs together support consumers' future requirements and lower overall cost.[112] In the Pricing review discussion paper we noted that:

Current network tariff approaches may not accurately reflect marginal costs. The current network tariff framework was designed when consumers, their agents, and CER technology were much less able to respond to dynamic short-run signals. The long-run marginal cost basis for setting tariff's produces consistent and predictable signals being broadcast to network customers. Customers face these signals and corresponding costs regardless of the likelihood that their individual or collective responses, in a particular place and time, could contribute to network cost reductions. In practice, the current network tariff framework may not accurately reflect marginal costs given today's context. This is a question we have identified for exploration, with these issues discussed in more detail in Appendix D.[113]

We further note in Appendix D that:

Networks are moving towards allocating consumers in the same tariff classes onto the same time-of-use tariffs, and occasionally the same demand tariffs. These time-of-use tariffs will 'broadcast' the same peak periods and charges to all consumers across the network, even though not all parts of a network experience peaks at the same time or are equally close to requiring augmentation. Our analysis shows that most parts of distribution networks are however not close to experiencing constraints. Networks for whom a greater proportion of their assets have a greater level of headroom are less likely to need to augment in response to peak demand growth.[114]

Our proposed policy options will improve the quality and availability of network data, including on network capacity and constraints. This could potentially facilitate alternative network pricing approaches by providing more accurate insights across the distribution network of the long run marginal costs for relevant areas (e.g. each zone substation). More accurate pricing signals would then help consumers make more informed choices about their energy usage that better reflect the

110 NSW transmission planning review, *Interim Report*, 27 June 2025, p. 93.
111 NSW transmission planning review, *Interim Report*, 27 June 2025, p. 93.
112 AEMC, The pricing review, *Discussion paper*, p 3.
113 AEMC, The pricing review, *Discussion paper*, p 57.
114 AEMC, The pricing review, *Discussion paper*, pp. 77-78.

impact on distribution networks, potentially reducing the need for network augmentations in the long term.

We would like to understand if stakeholders consider our proposed policy options would be sufficient to support dynamic network pricing approaches. We ask stakeholders to not only consider the proposed changes in network data reporting, but also the proposed distribution planning reforms. We note that distribution planning allows DNSPs to consider the trade-offs between network and non-network options, and identify which approach would be in the long term interest of consumers.

Question 16: Would our proposed policy options be consistent with the broader work programs currently underway?

Do you agree that our proposed policy options are consistent with the broader work programs?

If not, do you consider it is possible for our proposed policy options to be consistent with the other work programs? What change to the policy options do you consider would be needed and how would that address your concerns?

Are there other work programs that we have not considered that would also be impacted by our proposed policy options? What do you consider would be the impact of our proposed policy options on these other work programs? Do you believe any further reforms to the distribution planning process in the rules would be needed?

4 Next steps

We invite stakeholder submissions to the Directions Paper for four weeks until 13 November. We will consider all views and evidence raised in the submissions and may conduct further targeted stakeholder engagement where required. We also plan to continue working with the other market bodies, the AER and AEMO, through a working group.

If we decide to propose changes to the NER, the next formal step of our rule-making process will be the publication of a draft determination and draft rule in March 2026. Stakeholders will be invited to comment on the draft determination.

We will finalise our rule change process and publish a final determination and final rule (if made) in June 2026.

A We have assessed the two main policy approaches proposed by stakeholders

We undertook a detailed assessment of the two main alternative approaches that stakeholders proposed in their submissions to our consultation paper. These were:

- No changes to the current planning process in anticipation that other reforms will address the identified issues (appendix A.1)
- Implementing the proposed IDSP process, as set out in the rule change request, in full (appendix A.2)

This appendix provides further information on the assessments of each option.

A.1 We have considered the merits of making no changes to the distribution annual planning process

This section of appendix A sets out our evaluation of the merits of making no changes. It provides:

- an overview of the current distribution annual planning process in the rules (appendix A.1.1)
- an overview of the arguments for not reforming the distribution annual planning process appendix A.1.2)
- analysis on how the broader processes being progressed may address some of the identified issues that we set out in Chapter 2 (appendix A.1.3)
- analysis of how some of the issues identified would not be addressed by the broader planning processes (appendix A.1.4)
- our evaluation of the case for not making changes to the distribution annual planning process against our assessment criteria for this rule change request (appendix A.1.5).

A.1.1 The current distribution annual planning process

Currently, each DNSP is required to analyse the expected future operation of its network and report this in a Distribution Annual Planning Report (DAPR).[115] A forward planning period of at least five years is specified.[116] The review must include all assets which are expected to have a material impact on the network over the forward planning period.

Forecasts must be prepared covering maximum load demand and embedded generation demand for sub-transmission lines, zone substations, and primary distribution feeders (to the extent practicable), and have regard to the number of customer connections, energy consumption and the estimated total output of known embedded generation.

DNSPs must consider:

- network limitations caused by forecast load and embedded generation
- asset refurbishment or replacement
- supply security or reliability improvement
- fault level exceedance
- voltage regulation

115 Rule 5.13, National Electricity Rules.
116 Rule 5.13, National Electricity Rules.

- regulatory compliance.

DNSPs must also identify corrective actions.

The Regulatory investment test for distribution (RIT-D) must (with some exceptions) be applied to projects expected to exceed a value determined by AER, currently set at $7M.[117]

A RIT-D is a cost-benefit analysis of feasible options for distribution augmentation projects triggered by the identification of network limitations in the planning process above and is subject to a stakeholder consultation process. The AER is required to publish a RIT-D consultation guideline in accordance with the distribution consultation procedures in Rule 6.16 of the NER.[118] The guideline published by the AER offers DNSP's some flexibility in how they approach stakeholder consultation but sets minimum requirements including minimum consultation periods and social licence considerations.[119] The AER makes a determination against each RIT-D and publishes relevant information on their website.

Additionally, demand-side obligations must be met, including an engagement strategy for non-network providers and consideration of non-network options.

The outcomes of the planning review are reported in the DAPR

As noted above, each licensed DNSP must prepare a Distribution Planning Annual Report (DAPR) that reflects the outcomes of the annual planning review of each network. The DAPR, which may be presented in both a publicly accessible document and condensed portal form by some DNSPs, informs network participants and stakeholder groups of the proposed development of the DNSP's network, including potential opportunities for non-network solutions and possible investments. Customer and stakeholder groups provide input into the DAPR under an engagement strategy prepared by each DNSP.

The DAPR is intended to provide an understanding of the various investment programs and projects being undertaken and provides a "snapshot" of network investment expected by each DNSP over the following five years.

Coinciding with the issue of the DAPR, a DNSP must also publish distribution system limitation information in a template published by the AER as specified in clause 5.13.3 of the NER. This is intended to provide information in the DAPR in a "useable, consistent, accessible format to assist third parties to propose alternative options to address system limitations". The template must include the:

- name (or identifier) and location of substations, sub- transmission lines, zone substations and, where appropriate, primary feeders, where there is a system limitation or a projected system limitation during the forward planning period that has been identified in a Distribution Network Service Provider's Distribution Annual Planning Report
- estimated timing (months(s) and year) of the system limitation or projected system limitation
- Distribution Network Service Provider's proposed option to address the system limitation
- estimated capital or operating cost of the proposed option
- amount by which peak demand at the location of the system limitation or projected system limitation would need to be reduced in order to defer the proposed solution
- dollar value to the Distribution Network Service Provider of each year of deferral.

117 Australian Energy Regulator (AER), *2024 RIT and APR cost threshold review –final determination*, November 2024; Rule 5.17, Regulatory investment test for distribution, National Electricity Rules; AER, *Regulatory investment test for distribution application guidelines*, November 2024.

118 Clause 5.17.2, National Electricity Rules.

119 Clause 4, *Regulatory investment test for distribution application guidelines*, AER, November 2024.

A.1.2 There is sufficient evidence to demonstrate that the distribution annual planning process is no longer fit for purpose

Several stakeholders suggested that there was no need to make changes to the distribution annual planning process under this rule change. Some thought that there was insufficient evidence to support changing the planning process or that it remained fit for purpose.[120] However, we consider that our analysis in chapter 2 demonstrates that the current distribution annual planning process is no longer fit for purpose, particularly given the ongoing uptake of CER.

A.1.3 Some of the identified issues may be addressed by other work programs

Other stakeholders also argued that the distribution annual planning process should not be amended or only subject to very limited changes under this rule change. They considered that the issues that the ECA raised were already being explored in other programs of work, particularly the various national CER roadmap projects. They argued that making changes now may pre-empt the outcomes of these other processes and create inconsistencies. Instead, they considered it would be better to wait until after these other processes to make changes to the distribution annual planning process.[121]

For example, Energy Networks Australia suggested that "DNSPs will continue to improve data sharing as more data becomes accessible … through the smart meter accelerated rollout" and recognised several other initiatives underway while expressing caution about additional stakeholder consultation and low-value, high-cost data, each of which may increase customer costs without any direct benefit (in their view).[122]

AEMO also submitted that:

There is a large body of work underway under the National CER Roadmap that is examining how best to design and implement CER data sharing arrangements to inform planning and enable future markets. This includes a proposed action for the development of a National CER Data Strategy and Coordination Plan as well as work to resolve challenges including transmission-distribution coordination and interfaces, CER asset registration and commissioning and detailed design and implementation of the CER Data Exchange. This work has been a collaborative process between jurisdictions, market bodies and industry over multiple years…. AEMO encourages the AEMC to consider how the work underway on data collection and sharing can be leveraged to address the issues raised by the ECA.[123]

We agree with stakeholders that some of the data challenges we identified in chapter 2 could potentially be addressed by the national CER roadmap projects. There are several programs under way that are exploring data issues, including:

- *Data Sharing Arrangements – M2*
- *Redefine roles for market and power system operations – M3/P5.*[124]

The Redefine roles for market and power system operations – M3/P5 project may also identify new planning requirements for DNSPs. It is currently exploring the Distribution System Operator role, including whether this role should be assigned to the DNSPs. This may lead to changes in planning requirements and processes under the rules.

120 See for example, Ergon Energy Network and Energex submission to the consultation paper, p. 1.
121 See for example, Energy Networks Australia submission to the consultation paper, pp. 1-2; AEMO submission to the consultation paper, pp. 2-3.
122 Energy Networks Australia submission to consultation paper.
123 AEMO submission to consultation paper, p. 3.
124 National CER Roadmap, July 2024.

We note that the above projects are partially related to the information component of this rule change request, but they are unlikely to change the rules directly. Any changes to the rules as a result of these processes would rely on future rule changes to be implemented. Waiting for these would delay the benefits flowing from this rule change request. Further, it would also delay any changes to the existing distribution planning process.

Instead of waiting for these processes and the subsequent rule change processes to complete, we propose making rules in a manner that can incorporate the outcomes of the above processes and potentially provide some quick wins for them. As noted in chapter 3, we expect to have the benefit of the final first stage reports for the above M2 and M3/P5 workstreams prior to making a draft determination. We intend to propose rules that complement and support these workstreams and the report outcomes in the long term interests of consumers.

We would also expect that the DNSPs would continue building their data reporting capabilities during this period. However, as set out in chapter 2, there is a material risk that independent DNSP action will lead to different levels of data transparency and reporting across the NEM, as well as diverse data and information formats. This will continue to be the case until there are standardised requirements for data reporting.

A.1.4 It is not clear how other programs would reform the planning process to address the identified issues

It is not clear how the non-data distribution network planning challenges identified in chapter 2 would be addressed by other reform programs. The availability of more comprehensive datasets under the current rules, accompanied by enhanced presentation platforms, does not result in any direct changes to the process underlying the preparation of a DAPR.

Further, the other reform programs underway may ultimately produce considerable information that is outside the data specification for the DAPR in the current rules, so once (and if) these come to fruition they would exist side-by-side with the DAPR with no direct coordination in the preparation or presentation of planning information.

The AER low-voltage network visibility project included a trial to provide data to support the Victorian Neighbourhood Battery Initiative (NBI).[125] The trial found that "*information available to NBI participants from DNSPs did not meet their needs*". The project final report supports aspects of the ECA proposal through the provision of distribution network import and export capability, and voltage and reliability data at the high voltage feeder and distribution substation level. A preference was expressed for network data to be presented in the form of a geographic map where possible, and in the longer term, incorporation into the proposed CER Data Exchange using standardised data formats. These recommendations are instructive in terms of the data specification required to support the adoption of CER.

If we acknowledge that the DAPR in its current form does not meet the needs of one or more of its target audiences, or, indeed, the DNSPs themselves in their proposed future role as a DSO, then data sharing outside the DAPR process intended to compensate for deficiencies in the DAPR does little to correct the underlying problem. Over time, the risk of parallel processes, duplicated effort, conflicting and inconsistent datasets, multiple deadlines and versions and the regulatory burden of assessing compliance all increase with the amount of data available in the absence of a single-point of regulation and coordination. This may in turn degrade the content of the DAPR, decrease its relevance, and result in inaccuracies or delays in its preparation. Changes to the DAPR process

125 AER, Low-voltage Network Visibility, *Phase 3 Final Report*, 31 March 2025.

should be considered as complementary to the reforms currently underway and ultimately, form a key enabling mechanism.

A.1.5 Relying on other reform processes does not sufficiently address our assessment criteria

We have examined the case for relying on other reform processes and not proceeding with a rule change, and concluded that this does not sufficiently align with our assessment criteria, as follows:.

- ***Safety, security and reliability****: to assess incentives for efficient system service capability to deliver (these) outcomes, as well as the grid's resilience to the impacts of climate change.*

  The absence of a rule change will not further promote efficient investment in networks and other system service capability.

- ***Principles of market efficiency:*** *to assess how we can best use competition, transparency, incentives and risk allocation to deliver more efficient outcomes for consumer benefits.*

  The absence of a rule change will not improve transparency or create incentives that improve competition in downstream markets (e.g. EV charging).

- ***Emissions reduction:*** *to assess whether the proposed reforms would efficiently contribute to achieving government targets for reducing, or that are likely to reduce, Australia's greenhouse gas emissions*

  The absence of a rule change will not efficiently contribute to achieving government targets as it will not promote improved integration of CER.

- ***Implementation considerations:*** *to assess cost and complexity, timing and uncertainty, and the ability of the approach to apply across jurisdictions to achieve consumer benefits*

  We anticipate that the absence of action will not help build trust and social licence, nor will it assist in achieving the consumer benefit objectives of the reforms underway.

- ***Principles of good regulatory practice****: to assess whether the proposed reforms would better balance tradeoffs between regulatory considerations like the predictability of prescriptive rules and the flexibility and future-proofing of adopting simple, principles-based rules*.

  We anticipate that the absence of a rule change will result in greater complexity and expense over time while not supporting the consumer benefit outcomes of reforms already underway

The absence of a rule change would partially satisfy:

- ***Implementation considerations:*** The absence of a rule change will not create additional cost and complexity while other reforms are being considered, and will not add further uncertainty. However, we consider that this outcome would only be in the short term and that additional cost and complexity will be incurred over time in the absence of a rule change.

Overall, we consider that the case for retaining the current rules without change is not strong, but we acknowledge the need to ensure any changes are aligned with the broader reform processes currently underway and those being considered for future adoption.

A.2 Implement the proposed IDSP process in full

As noted in chapter 3 and above, we have assessed the merits of implementing ECA's proposed Integrated Distribution System Planning (IDSP) process as a means of addressing the identified issues. We undertook this assessment as we agreed with many of the issues ECA raised in their rule change request (chapter 2) and multiple stakeholders provided their support for an IDSP process.

While ECA put forward a broad ranging proposal, there were still elements of the process that were unclear in the rule change request. For example, it was unclear how the proposed biennial cycle would practically integrate with the ISP process. We have attempted to clarify these elements when developing our assessment so that we can carefully consider the advantages and disadvantages of the proposed IDSP.

This section of Appendix A provides more information on our assessment of the proposed IDSP process. It sets out:

- how we consider the proposed IDSP process would operate (appendix A.2.1)
- the advantages and disadvantages of the proposed IDSP (appendix A.2.2)
- our assessment of the proposed IDSP against our assessment criteria (appendix A.2.3).

A.2.1 The proposed IDSP process would replace the current distribution annual planning process

The distribution annual planning process is a mature and well-understood technical process, as submitted by some stakeholders.[126] Effectively replacing this process, as ECA has proposed with the IDSP, would require the new process to be clearly set out in the rules. We consider that for this to occur, the proposed IDSP process would need to look similar to the following:

- replace the current annual planning review with a biennial IDSP review
- require DNSPs to conduct the IDSP review down to at least the zone substation level
- require DNSPs to develop CER hosting capacity and distribution network constraints down to the low-voltage transformer or distributor level over a five-year horizon, using different scenarios that align overall with the ISP unless a variation can be justified
- replace the current minimum planning horizon of five years for the annual planning review with a 20-year project horizon and a 10-year action period for the IDSP review
- require DNSPs to incorporate smart meter and other data into their network planning processes
- require DNSPs to incorporate modelling inputs from the most recent ISP
- require DNSPs to conduct a risk assessment of its network's vulnerability to severe weather and assess how it can support consumer electricity resilience
- establish new stakeholder engagement obligations for DNSPs to consult with a broad range of stakeholders during the IDSP review, with a particular focus on local communities
- also establish an obligation for DNSPs to consult with local gas networks during the IDSP review to understand the impact on local electricity demand from gas network disconnections.

The DAPR would be replaced by a biennial IDSP report

New reporting obligations would also be needed for the IDSP process. We consider that the first change would be to replace the DAPR with an IDSP report that captures the outcomes of the IDSP review. This would potentially require DNSPs to:

- continue reporting on the current DAPR information
- publish significantly more data about current and anticipated CER uptake and low-voltage hosting capacity
- provide demand-side factor data for the next ISP (i.e. the IDSP reports would therefore act as inputs into AEMO's Inputs, Assumptions and Scenarios Report (IASR), a key component of AEMO's ISP development process)

126 Endeavour Energy submission to the consultation paper, p. 14; Ausgrid submission to the consultation paper, p. 3.

- report on any variations the DNSP adopted from the ISP scenarios used for the IDSP review
- publish aggregated smart meter data and other low-voltage data where available
- provide an overview of "lessons learned" from the DNSPs stakeholder engagement during the IDSP review
- publish identified distribution network areas with the greatest need for energy storage
- report on the outcomes of the DNSP's risk assessment of its network's vulnerability to severe weather and how it would support consumer electricity resilience.

The proposed IDSP would require DNSPs to publish and regularly update CER hosting capacity maps

DNSPs would also be required to publish some information and data outside of the IDSP report so that it can be provided in a more dynamic and timely manner. To start with, DNSPs would be required to provide their network's CER hosting capacity data in an online opportunity map, at least to the zone substation level of granularity, within two years. The maps would then need to be updated at least every three months by the DNSPs, and not necessarily in real-time.[127]

In preparing this data, the DNSPs would be required to protect the privacy and confidentiality of individual energy consumer data. This would include information about energy consumption and CER uptake, which would be protected through appropriate tools and methods, such as data aggregation. Information from sensitive facilities, such as defence installations, would also be protected through provisions in the guidelines that standardise the IDSP process (see below).

The proposed IDSP would require DNSPs to prepare a Network Data and Insights Roadmap

In addition to the IDSP report, the DNSPs would also be required to develop and publish a Network Data and Insights Roadmap by July 2027. The date of July 2027 would be about one year after the expected release of the final rule(s) of this project. This roadmap would need to be updated by the DNSPs every two years and released with their IDSP report. While the roadmap would be used to support the DNSPs' transition to the IDSP process, it would not have a clear end date. Instead, it would evolve into a continuous improvement tool to provide transparency on how DNSPs are improving their data collection and publication capabilities.[128]

In the proposed Network Data and Insights Roadmap, DNSPs are required to outline their methods and calculations used. The roadmap provides its data in a consistent form across all DNSPs and outlines each DNSP's process to improve data collection and publication.

We expect the proposed IDSP report would also need to capture the outcomes of DNSP's joint planning activities and RIT-D projects

While it was not mentioned in the rule change request, DNSPs would still be required to conduct joint planning with TNSPs (NER clause 5.14.1) and other DNSPs where there are issues that affect more than one network (NER clause 5.14.2). DNSPs are currently required to report on these joint planning activities in the DAPR.[129] We consider that, under the IDSP process, these joint planning activities would need to be captured in the biennial IDSP report given it would replace the DAPR. We note that this would reduce the publication frequency of joint planning outcomes.

Similarly, DNSPs are also required to provide a high-level summary of each RIT-D project it has completed in the previous year or is in progress in its DAPR.[130] While it was not mentioned in the

127 ECA submission to the consultation paper, p. 5.
128 ECA submission to the consultation paper, p. 9.
129 NER Schedule 5.8, clauses (h) and (i).
130 NER Schedule 5.8, clause (e).

rule change request, we consider that this summary would also need to be captured in the IDSP report as the DAPR's replacement and in line with Schedule 5.8 of the NER. We note that this would also reduce the publication frequency of RIT-D summaries.

The proposed IDSP process would require changes to multiple rules in the NER

Based on our understanding of how an IDSP process would work, we expect that multiple rules in Chapter 5 of the NER would need to be changed. Specifically, changes would be needed for Rules 5.13, and 5.13A, schedules 5.8 and 5.9. These rules and schedules establish the distribution annual planning process, its consultation and reporting requirements, and also reporting requirements for distribution zone substation information.

The proposed IDSP would require the AER to create guidelines and templates to standardise the IDSP process' implementation

The proposed IDSP process would require the AER to play a larger role in the distribution planning process. The AER would be expected to create consistency in the IDSP's implementation by the DNSPs. ECA proposed to achieve this by requiring the AER to:

- develop guidelines for data collection to create standardised datasets
- develop guidelines for the methodology and outputs for IDSP modelling
- prepare guidelines and templates for the proposed Network Data and Insights Roadmap
- perform regular benchmarking of DNSP planning methodologies, IDSP inputs and outputs.

We also consider that the AER would also need to produce guidelines for the proposed stakeholder engagement obligations for the IDSP review. The guidelines would be intended to create the standardised formats for the stakeholder engagement by the DNSPs that ECA proposed in its rule change.

Similarly guidelines would also be needed to assist DNSPs in establishing robust processes for protecting privacy (individuals and sensitive facilities) when collecting and publishing data. This could be as part of the proposed AER guidelines for data collection or as a separate guideline that is specifically focused on privacy issues.

ECA also proposed standardising the definition and calculation of CER hosting to allow comparisons between different IDSPs. As ECA outlines in their rule change request:

Careful definition of these terms must be undertaken by the AER or another body independent of DNSPs and standardised across DNSPs and IDSPs to ensure consistency.[131]

While this could be addressed in the NER, we consider that this standardisation would likely be most efficiently delivered through an AER guideline.

A.2.2 We consider that the disadvantages and costs for the proposed IDSP model are likely to be more significant than its benefits

We have considered the likely benefits as well as the likely disadvantages and costs of the proposed IDSP model, as outlined below. On balance, we consider that the disadvantages and costs outweigh the benefits. While the proposed IDSP would address some of the issues raised in chapter 2, we do not consider that it would be more effective than our proposed policy options in chapter 3 but it would be more difficult to successfully implement.

131 IDSP RCR, p. 4.

We consider the proposed IDSP would address some of the issues identified in Chapter 2

We consider the proposed IDSP would be well placed to address some of the issues we have identified in chapter 2. Its proposed data reporting requirements are comprehensive and would improve the information available to consumers, and other stakeholders, on the state of the distribution network. As ECA submitted, this can create benefits such as reduced curtailment of rooftop solar and helping large energy users to optimise their approach to network connection.[132] We note that we anticipate similar benefits from our proposed policy options in chapter 3.

The proposed Networks Data and Insights Roadmap would also establish a clear requirement on DNSPs to improve the quality of data collected, used and published in greater spatial granularity over time. This would provide energy consumers with confidence that the quality of distribution network data available to them would reach a consistently high level across all DNSPs, not dissimilar to our proposed network data reporting requirements in chapter 3.

The more granular network data being made available as part of the IDSP process would likely not be utilised by energy consumers, but by their agents. It would also support the activities of companies and other organisations in the CER space, for example, as operators of virtual power plants or community batteries. Having this more granular network data could lead to better location of such resources within the distribution network based on hosting capacity. However, given that the proponent does not propose a requirement for DNSPs to publish real-time data, the benefits for operating such resources from more granular network data is likely very limited.

The proposed IDSP would also address some of the shortcomings identified with the strategic planning of distribution networks identified in chapter 2. It would require DNSPs to adopt a longer planning horizon than the current distribution annual planning process. There would also be closer alignment between the ISP scenarios, particularly the identified optimal development path, and the distribution-level planning done by DNSPs. This potential benefit would need to be balanced against the need for DNSPs to address specific local factors in their strategic planning, such as high local uptake of CER and industrial developments such as data centres. As the Australian Energy Council outlines in its submission:

In this way systematic biases become visible, helping prevent costly coordination failures between transmission and distribution planning and exposing forecast biases before they translate into reliability or cost blowouts.[133]

A further potential benefit of establishing the proposed IDSP, would be increased stakeholder consultation. This covers engagements with local communities, particularly in the lead-up to each IDSP every two years. DNSPs would be required to share "lessons learned" from their stakeholder engagements. Stakeholder engagements would also follow a standardised process, which would allow consumers and consumer representatives a consistent engagement experience if they are dealing with multiple DNSPs. As outlined in the disadvantages section below, these benefits from increased consultation could be mitigated by the additional costs and stakeholder fatigue created.

We consider that the IDSP would be difficult to implement in practice

We consider that while the IDSP does address some of the short comings identified in chapter 2, it does not address them as fully our proposed policy options in chapter 3. In particular, while it would improve the strategic planning of distribution networks under the rules it is not clear that it is sufficiently robust to address the uncertainties created by the longer planning horizon, limiting its usefulness. For example, the use of scenario analysis would be limited to CER hosting capacity

132 IDSP RCR, p. 21.

133 Australian Energy Council submission to the consultation paper, p. 4.

and network constraints over a five-year planning horizon rather than more broadly used over the 20-year planning period.

The proposed IDSP would also place more stringent requirements on the interactions between distribution planning and the ISP than needed to address the issues identified in chapter 2. As noted there, we consider that DNSPs' distribution network plans can be better aligned with each other and the ISP. However, we do not consider further changes are needed to improve the quality of DNSP's inputs to the ISP for the IASR.

We expect making the IDSP a formal input to the ISP as ECA has proposed would likely impact AEMO's implementation of the *Improving consideration of demand side factors in the ISP* rule change. We expect it would lead to duplication with AEMO's current evolving process for incorporating DNSPs data into the ISP unless there are significant changes as noted above. It would also provide AEMO with less flexibility to tailor DNSPs' inputs to meet the requirements of the ISP than its current approach. There are also practical limitations with implementing this requirement as:

- Any input into the ISP would need to be provided during the IASR development phase of the ISP's two-yearly cycle.[134] As is shown on AEMO's ISP webpage, the draft IASR is released about 16 months prior to each ISP.[135] This would make the IDSP's proposed function as an ISP input impossible within the current ISP development framework.
- Changing the current ISP process to utilise an IDSP being published in the gap year between ISPs as an input would, at the very least, require very substantial and consequential changes to the ISP process, if it is possible at all. This could potentially have material consequences for the quality of the ISP, including the number of candidate paths and scenarios considered and/or opportunities for stakeholders to provide feedback to draft documents.

Another potential disadvantage compared with our proposed policy options would be reduced transparency about joint planning activities between DNSPs and TNSPs and, where required, between neighbouring DNSPs. Currently, such activities under NER clause 5.14.1 and NER clause 5.14.2 must be published by DNSPs in their annual DAPR. Under the IDSP model proposed by ECA, such joint planning would still take place, but reporting would occur only every two years in the IDSP and no longer annually. This applies similarly to transparency about the RIT-D summary, as per NER schedule 5.8.

The proponent also claims that the IDSP process would assist non-network options that may be least-cost options to address identified distribution network needs.[136] However, we have not received evidence to indicate that implementing the proposed IDSP would lead to increases in non-network option proposals for DNSPs to consider, compared to the current consultative arrangements.[137]

We also consider the proposed stronger stakeholder consultation requirements likely to result in significantly higher consultation costs for DNSPs and stakeholders. In addition, they present a high risk of stakeholder fatigue, as this new process would, in practice, duplicate the current extensive NER Chapter 6 consultation process.

We note that while we are supportive of greater transparency and data reporting, we expect that the proposed IDSP requirements would be more onerous than our proposed policy options. The

134 AEMO submission to the consultation paper, p. 2.
135 AEMO, 2026 Integrated system Plan, accessed 3 October 2025.
136 IDSP RCR, p. 20.
137 NER, clauses 5.13.1(e) to (j).

data requirements are more prescriptive and we anticipate that this will lead to higher reporting and collection costs. We also expect that the greater level of prescription would make the proposed IDSP less flexible than our proposed policy options. This increases the risk of duplication with the other work programs underway, most notably the *Data Sharing Arrangements – M2* project. It will also make it difficult to align the proposed IDSP with any recommendations or outcomes of the national CER roadmap compared to our proposed approach.

A.2.3 Alignment against the assessment criteria

As outlined in the consultation paper, we are considering the NEO and are applying five assessment criteria to this rule change. Our assessment of the IDSP process against these criteria is that:

- **Safety, security and reliability**: In our view, an IDSP process would potentially better enable the reliable, secure and safe provision of energy at an affordable cost to consumers over the long term, but this depends heavily on the final IDSP design chosen and would need to be balanced against the costs associated with establishing an IDSP process. The proposed IDSP's biennial frequency could present a worse outcome compared to the current distribution annual planning process, given that the frequency of publication would be less frequent. Due to timing constraints in the development of the ISP, the IDSP process would not be able to be used as inputs into the IASR in the current ISP process. Therefore, the market efficiency of integrated ISP and IDSP planning, as outlined by the proponent, is not likely to be realised.
- **Emissions reduction**: While the IDSP process could potentially result in more effective integration of CER in the distribution system compared with the status quo, this improvement in the planning process itself would not directly reduce emissions, though it may indirectly contribute.
- **Principle of market efficiency**: Requiring DNSPs to report greater amounts of distribution network information could help consumers and non-network stakeholders plan their investment in distributed energy resources. Currently, the information on distribution network hosting capacity available to energy consumers varies greatly between DNSPs beyond the current DAPR requirements.
- **Implementation considerations**: In our view the proposed IDSP is difficult to implement in practice. Its biennial approach will not align with the ISP process, preventing it from acting as an input for the IASR as intended. We expect it would also be more onerous to implement than our proposed policy options as there are more prescriptive reporting requirements. We note, that like some of our proposed policy options, the proposed IDSP may also lead to conflicting reporting requirements for Victorian DNSPs as they will also need to meet the requirements of the Victorian Electricity Distribution Code of Practice (the Code).
- **Principles of good regulatory practice**: The proposed IDSP is less flexible than our proposed policy options and we anticipate that this will make it challenging to align it with the outcomes of other reforms currently underway, such as the National CER Roadmap. We also consider that it will conflict with AEMO's ongoing implementation of the *Improving consideration of demand-side factors in the ISP* rule change into the ISP.

B Ampere Labs Technical Note Distribution Network Strategic Planning Landscape and Gap Analysis

Distribution Network Strategic Planning Landscape and Gap Analysis

This technical note provides an overview of the distribution network strategic planning landscape and an analysis of gaps in the strategic planning framework. The scope of this note is as follows:

- Summary of the current NER framework for distribution network planning, as well as relevant ongoing reviews
- Overview of the standard distribution network planning process
- Current framework for strategic planning relevant to distribution networks
- CER integration in the distribution planning process
- Implications and gaps

Current NER Framework and Ongoing Reviews

A summary of the relevant sections of the NER for distribution network planning is shown below in Table 1.

Table 1: NER sections relevant to distribution network planning

NER Clause	Relevant Content
NER 5.13: Distribution annual planning process	This rule covers the governance of the distribution annual planning process. It includes: • The forward planning period (minimum of 5 years) • Forecasting requirements • Network limitation identification • Corrective action identification • A requirement to consider jurisdictional electricity legislation. For example, this would include the Victoria Electricity Distribution Code of Practice (EDCoP). • Account for the general power system risk review • Consider frequency control schemes and protection and control systems and their interactions. • Consultation obligations • Reporting
NER 5.17: Regulatory investment test for distribution (RIT-D)	This rule covers the requirements for a RIT-D.

NER Clause	Relevant Content
	A RIT-D is used as a tool by the DNSPs to address an identified need that has a cost of greater than $5 million, for example, a zone substation limitation. In the context of electrification and CER, a limitation may arise for a variety of reasons including if forecasted demand and/or CER uptake would see a breach of equipment ratings or hosting capacity limits.
NER S5.1: System standards	Schedule 5.1 provides the technical requirements for which network service providers (including DNSPs) need to plan their networks.

NER S5.8: Distribution Annual Planning Report	Schedule 5.8 prescribes the minimum content required to be in the DAPRs
	Key items where it pertains to CER, EVs and electrification are as follows:
	• NER S5.8(a)(4) methodologies used in preparing the DAPR, including methodologies used to identify system limitations
	• NER S5.8 (a)(5) significant changes to forecasts and information provided in the preceding year's DAPR
	• NER S5.8(b) forecasts to include:
	  ○ (b)(2) load
	  ○ (b)(4) performance against any targets in a service target performance incentive scheme (STPIS)
	  ○ (b)(5) a description of factors that may have a material impact on its network
	• NER S5.8(c) information on system limitations for sub-transmission lines and zone substations
	• NER S5.8(d/d1) information of any feeder that is experiencing an overload/system limitation under maximum demand
	• NER S5.8(e) a summary of RIT-Ds from the preceding year or in progress.
	• NER S5.8(j)(5) performance of network including descriptions of processes that ensure compliance against reliability and relevant codes/standards/guidelines
	• NER S5.8(l) information on the DNSP's demand management activities

NER 5.22.6(a)(9): Demand Side Factors	The final determination on 19 December 2024 introduced demand side factors to be included in AEMO's ISP. The final rule: • Provides a broad definition of demand side factors

NER Clause	Relevant Content
	• Require AEMO to provide a statement that covers the expected development of demand side factors • Require AEMO to produce a demand side factors information guideline by 19 December 2025 (a year from the final determination) • Does not require information provided by DNSPs to AEMO to be published in the DAPRs, but instead to be published in the ISP database. The purpose of the rule change is to increase transparency into distribution developments and identify opportunities for distribution network developments. More information will be provided when AEMO produces their demand side factor statement and guidelines (currently in consultation stage).
NER 6.3.3: Demand management incentive scheme	Incentive to undertake efficient expenditure in non-network options for use in demand management, with an obligation on the AER to develop the scheme.
NER 6.3.3A: Demand management innovation allowance mechanism	Mechanism to allow DNSPs to fund research and development projects in demand management that have the potential to reduce long term costs, with an obligation on the AER to develop the mechanism.

NSW Transmission Planning Review 2025

The NSW transmission planning review is primarily focused on transmission network planning, but section 3 of the interim report touches on how distribution network planning, CER and consumer needs could be better integrated with transmission planning.

To this end, the draft recommendations include:

- Expanding distribution network assessment in the NSW System Plan and Infrastructure Investment Objectives reports, for example requiring the NSW System Plan to "*evaluate how distribution-level solutions such as demand response, distributed storage, voltage management or local network augmentation could defer or avoid the need for strategic transmission investments*".

- Expand non-network solution assessment as an alternative to strategic transmission projects, including demand response, BESS, virtual power plants and industrial load management.
- Integrated forecasting coordination to "*incorporate forecasts of major new load connections to the distribution network, CER uptake, distributed generation and demand growth*".

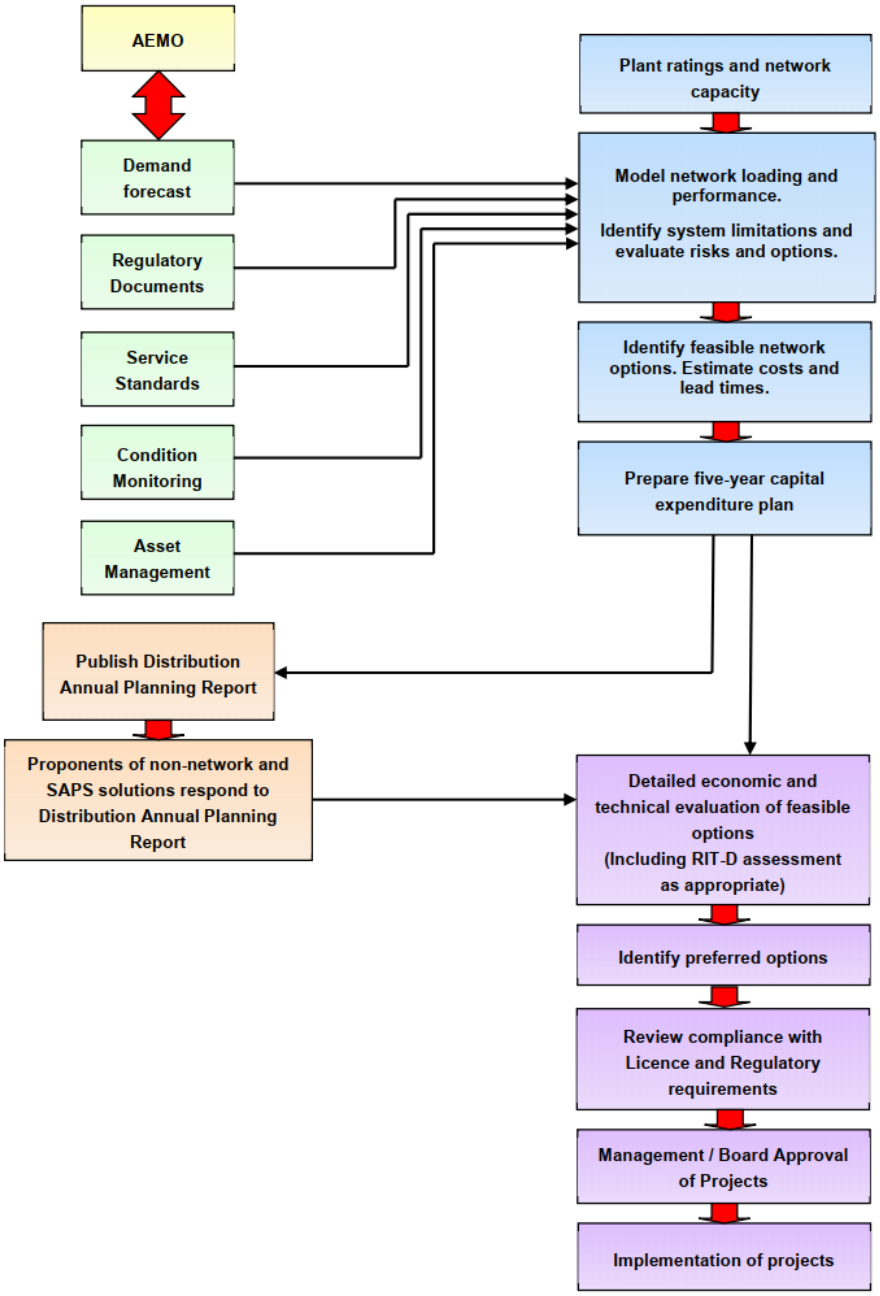
These recommendations reflect several key IDSP concepts laid out by Berkeley Lab, such as:

- The coordination of different planning processes in generation, transmission, distribution and operation that may be conducted by different entities (in this case AEMO, EnergyCo, Transgrid and the DNSPs); and
- The holistic consideration of all options to alleviate system limitations (including non-network solutions at both transmission and distribution level).

Standard Distribution Network Planning Process

DNSPs tend to follow a '*standard*' distribution network planning process based on engineering planning principles that have largely remained unchanged for several decades (i.e. planning the network for maximum demand). The following flowchart illustrates inputs and processes (Figure 1). This is representative of how DNSPs approach distribution network planning.

Figure 1: Representative DNSP annual planning process [Source: Jemena 2024 DAPR]



The distribution network planning process is used to determine replacement expenditure (repex) and augmentation expenditure (augex).

Replacement planning process

The condition of existing network assets drives the need for replacement expenditure and involves an assessment of ageing and end-of-life assets, as well as degraded and/or unreliable assets. Assessments are also undertaken to inform the potential decommissioning of existing assets. For example, the cost of replacing the assets in an ageing substation may be too high to justify, and it may be more efficient to decommission the substation and transfer the loads to other nearby substations.

Augmentation planning process

Planning for network augmentations is driven by demand forecasts (including major customer growth) and service performance.

The impact of future (forecasted) demand over the 5-year forecast outlook on the existing network infrastructure is analysed using power system models, typically for system normal (N) and contingency (N-1) cases[1]. This analysis is conducted to identify limitations such as:

- **Capacity limitations:** thermal overloading of network assets (for example, lines, cables, transformers, etc)
- **Voltage limitations:** voltages outside of the acceptable voltage range articulated in the planning criteria (for example, 90% to 110% of nominal voltage).

The analysis has traditionally been conducted solely for maximum demand scenarios (summer or winter peak demand events), but minimum demand scenarios are increasingly being studied, particularly in jurisdictions with high CER uptake. As per NER S5.8, DNSPs are obliged to report on limitations for sub-transmission lines, zone substations and primary distribution feeders.

Network augmentation options are developed to alleviate the identified limitations. Examples of network augmentations include upgrading a line or transformer, installing a new line and transferring load from one substation to another.

The risks arising from any limitations identified are quantified (for example, in terms of unserved demand) and assessed against the network augmentation options. It is noted that

[1] In contingency (N-1) cases, the power system analysis is performed with the assumption that one network asset is out of service (whether for maintenance or due to a forced outage, for example, lightning, fire, asset failure, etc).

DNSPs may approach the risk quantification in a deterministic manner (based on whether the limitation will materialise given the demand forecast, irrespective of whether the outage conditions that would cause the limitations are likely to occur) or in a probabilistic manner (which consider the probability of asset failures that leads to limitations arising). DNSPs applying the probabilistic approach include the Victorian DNSPs, EvoEnergy and Endeavour Energy.

Non-network options (such as demand management) are solicited from the industry and any proposed options are evaluated together with the network options in a techno-economic assessment, which could include a public Regulatory Investment Test for Distribution (RIT-D) for projects above a cost threshold (currently $7m).

Preferred options are selected from the techno-economic assessment and once approved, the projects are implemented.

Strategic Planning in Distribution Networks

Current DNSP approaches

In addition to the standard planning approach, DNSPs *may*[2] also conduct strategic planning over a longer horizon than the mandatory 5-year DAPR forward outlook. Strategic planning could include activities such as:

- Planning for new zone substations (and load transfer capability), particularly for greenfield developments and medium- to long-term load growth
- Planning for strategic asset retirements, e.g. to coincide with planned upgrades and consolidations
- Planning the sub-transmission and dual function transmission network

TasNetworks, as both the TNSP and DNSP of Tasmania take an integrated approach to planning both the transmission and distribution network, including 15-year network strategies. Ausgrid, which owns and operates a significant number of dual function transmission assets, also plans over a longer horizon (Ausgrid Area Plan strategies are considered over a 20-year investment outlook).

While not always explicit in their publicly available documents, other DNSPs conduct longer term strategic planning, particularly for greenfield developments and area-based strategies. A good example of this type of strategic planning is Endeavour Energy's Western Sydney

[2] There is no explicit NER requirement, but it is generally expected that DNSPs will plan over a longer horizon than 5-years.

Aerotropolis Area Plan that was submitted to the AER as part of their 2024-2029 regulatory proposal. The Aerotropolis is a greenfield 11,200 ha development in the area surrounding the new Western Sydney airport, with plans for development out to 2046. However, this long-term strategic information is typically not covered in the DAPR (beyond immediate developments falling within the 5-year forward outlook).

Moreover, DNSPs are required to report on joint planning activities with TNSPs and other DNSPs undertaken over the preceding year (NER S5.8(i) and(j)). By implication, joint planning exercises with TNSPs would be strategic in nature and have at least a 10-year forward outlook.

AEMO Integrated System Plan (ISP)

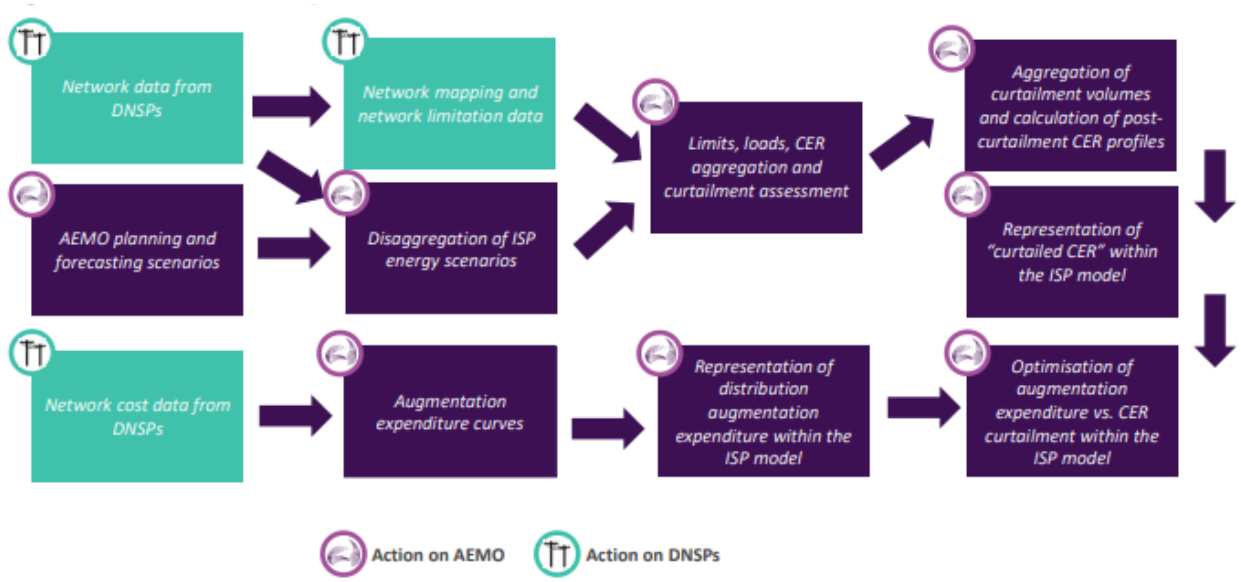
In previous ISPs, the distribution network has not been explicitly considered. AEMO developed long-term forecasts for CER (including EVs) and distribution-level electrification, but it was assumed that these can be integrated into distribution networks in an unconstrained manner, i.e. either the distribution networks are assumed to have sufficient capacity or they would be augmented to facilitate the CER and electrification forecasts.

Under the new demand side factors process for the 2026 ISP, AEMO will be collecting information from DNSPs on the capability and limits of the distribution network, as well as augmentation costs to unlock distribution network transfer capacity (in $/MW). The Demand Side Factors Information Guidelines is currently under consultation, but the consultation report and Electricity Network Options report indicate that most DNSPs have opted for the "standard pathway" of data collection (see Figure 2). In this pathway, AEMO are responsible for estimating the distribution network import/export transfer capacity at each sub-region (in MW), calculating the aggregate volume of CER curtailment that will be seen by the ISP model and determining the augmentation cost curves for alleviating curtailment.

Therefore, the 2026 ISP model will for the first time attempt to **optimise CER curtailment against distribution augmentation investment** (albeit in a coarse manner as there are only 15 sub-regions / nodes representing the NEM in the ISP model). The 2026 ISP is expected to provide a rough distribution network augmentation investment value for each sub-region, which may guide DNSP planning, but does not provide specific details on the augmentations required. For example, the ISP model outputs may recommend that a sub-region's distribution networks increase their export transfer capacity by 250 MW to alleviate CER curtailment at a blended cost of $0.6m per MW, resulting in an aggregate investment cost of $160m (to be shared across the DNSPs in the sub-region).

The 2026 ISP also considers larger scale distributed generation and storage (up to 30 MW) in a similar way to CER, with a notional distribution network transfer capability for distributed generation and storage at each sub-region (in MW) and a distribution network augmentation cost (in $/MW).

Figure 2: Standard pathway for DNSP asset data collection [source: AEMO]



CER Integration in the Distribution Planning Process

The large-scale integration of CER[3] into distribution networks poses a philosophical quandary for the distribution planning framework as it does not neatly fit within the standard distribution planning process described earlier. The consideration of CER integration is currently applied by DNSPs such as Ausgrid, AusNet and SAPN as a separate planning process (in parallel with the standard process), based on an AER guidance note on CER integration expenditure.

CER hosting capacity analysis has emerged as the de facto approach for considering CER in the distribution planning process

CER hosting capacity refers to the maximum amount of CER that can be connected to a specific part of the distribution network (typically reported by DNSPs at zone substation or primary distribution feeder level).

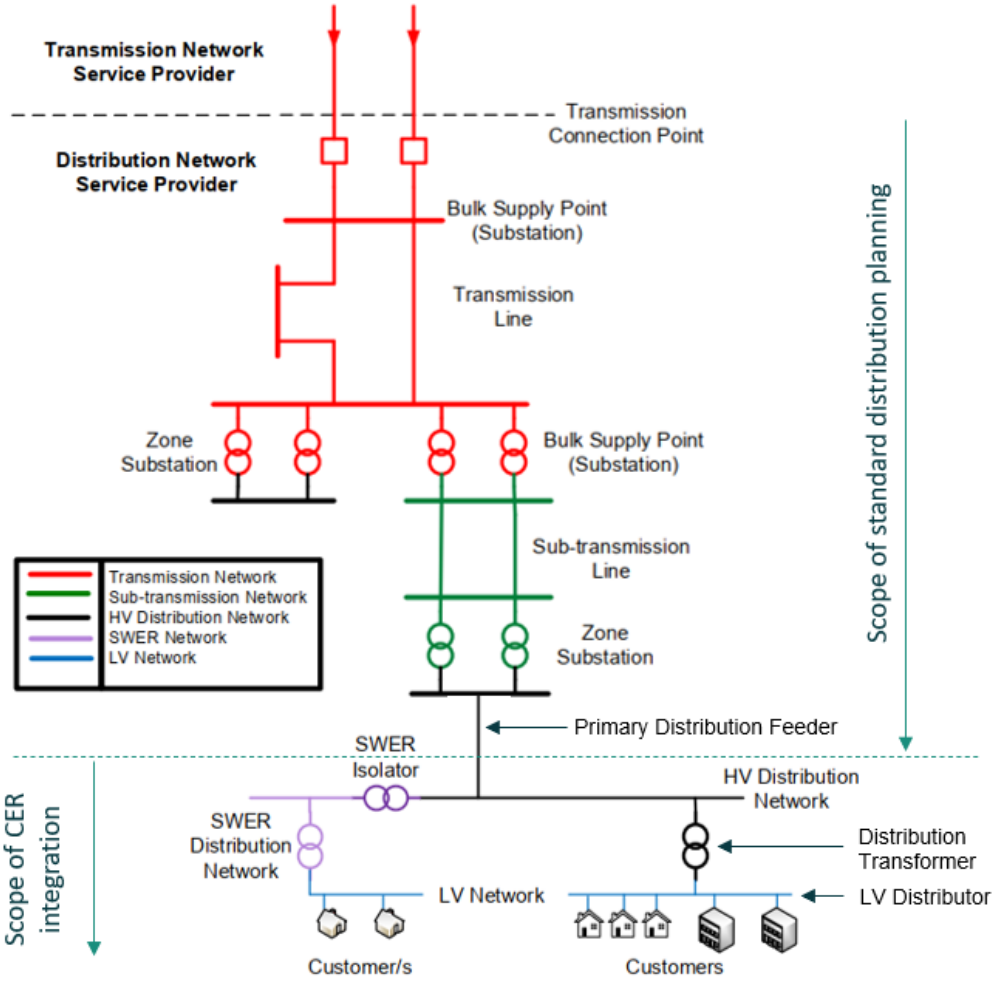
In principle, CER hosting capacity limitations are predominantly driven by either voltage (most common), thermal overloading or power quality issues. However, DNSPs have flipped the framing of these issues as limitations on CER hosting capacity, rather than network constraints (for example, voltage or thermal overloading issues) that need to be addressed through standard distribution network planning. In other words, the first action taken by DNSPs in

[3] Including customer-level devices such as rooftop solar PV, small-scale BESS, EV chargers and controllable loads like hot water systems, air conditioners and pool pumps.

response to voltage or thermal overloading issues due to CER is to restrict the connection of new CER.

Limitations that drive CER hosting capacity typically occur at the medium and low voltage level, e.g. primary distribution feeders, LV distribution transformers or LV distributors, which DNSPs perceive as sufficient justification to functionally separate the standard planning and CER integration processes (even though there would be unavoidable overlaps).

Figure 3: Scopes of standard planning and CER integration processes [source: Energy Queensland]



There is currently no obligation in the NER for DNSPs to develop (and publish) CER hosting capacity. However, DNSPs with high rates of CER installation are increasingly adopting more sophisticated approaches to calculate CER hosting capacity at higher levels of spatial resolution (i.e. down to the LV consumer level). For example, SAPN have been performing CER hosting capacity analysis since before 2020 but have continually evolved and improved their approach into a powerful internally developed software tool (called the LV Planning Engine).

For some DNSPs, such efforts are partly in response to the AER's CER integration expenditure guidance note, that explicitly refers to CER hosting capacity analysis as a means for justifying expenditure. DNSPs can specifically propose expenditure for CER integration purposes that is distinct from more traditional planning expenditures (i.e. addressing network limitations to increase hosting capacity in lieu of limiting new CER entry).

The AER listed a set of CER "value streams" that the proposed expenditure needs to be compared against, including wholesale market benefits (avoided generation operational and capital investment costs), reliability, avoided or deferred network capex, avoided greenhouse gas emissions, etc. It is noted that the optimisation of CER curtailment against distribution network augmentation planned for the 2026 ISP will only quantify wholesale market benefits.

There are currently multiple different approaches for calculating CER hosting capacity

The standard distribution network planning process is mostly shared across all DNSPs, with differences mainly relating to the economic assessment of investments (for example, deterministic or risk-based). All DNSPs adopt the same fundamental technical approach[4], which has evolved over the past 50+ years.

However, as CER hosting capacity analysis is still relatively nascent (roughly a decade old), there is no standard or universally accepted approach for performing the analyses. DNSPs have developed or adopted different methods for modelling hosting capacity (see Table 2), some of which are from commercial third-party vendors (e.g. Zepben and GridQube).

Differences in approach include:

- The underlying calculation method, for example, power flow model-based vs model-free approaches.
- Forecasting approaches for CER and EV uptake.
- Behavioural and coordination assumptions for BESS, EVs and controllable loads.
- Treatment of existing uncontrolled CER stock that are coming to their end of life, for example, is there progressive replacement of existing uncontrolled CER with new controllable CER?
- Scenario development and selection for investment planning.

Given the relative immaturity of CER hosting analysis (compared to standard planning), it remains unclear how robust and accurate different modelling approaches and assumptions are in developing justifiable investment plans.

[4] The shared approach uses power flow analysis to determine thermal and voltage limitations in system normal (N) and contingency (N-1) conditions for peak and minimum demand scenarios.

Table 2: Hosting capacity modelling approaches

DNSP	Hosting capacity modelling approach
Ausgrid	Hosting capacity analysis based on a CER integration forecast using an agent-based model.
AusNet	Internally developed hosting capacity analysis tool using an Excel spreadsheet-based model with actual measurement data (for example, voltages, loads, flows, etc) from SCADA and smart meter infrastructure to identify network limitations. "Model-free" approach was developed in conjunction with the University of Melbourne.
CitiPower / Powercor / United Energy	Deployed software vendor Zepben's Energy Workbench platform as the underlying hosting capacity model, which uses open-source software OpenDSS as the power flow engine.
Endeavour Energy	Developed a hosting capacity assessment and simulation tool conjunction with the University of Wollongong's Australian Power Quality and Reliability Centre, using open-source software OpenDSS as the power flow engine.
Essential Energy / Energy Queensland	Use a power flow based approach developed by GridQube / Luceo Energy (described in the ARENA-funded Project SHIELD).
SAPN	Hosting capacity estimates using an internal software tool (LV Planning Engine), which uses a power flow solver to identify network constraints and evaluate potential investment solutions.

Implications and Gaps

The medium- to long-term network impacts of rapid electrification, CER and EV growth are not publicly visible over the 5-year distribution planning horizon

DNSP forecasts in the 2024 DAPRs indicate accelerating growth of EVs after 2030. Similarly, the 2024 ISP is expecting CER storage (both passive and coordinated) to grow significantly from 2029-30, while rooftop solar capacity is expected to continue growing through to 2050. Victoria and the ACT are also expecting material electrification of natural gas demand (via state government initiatives like Victoria's Gas Substitution Roadmap).

These forecast trends will have an impact on distribution network demand and power flows over the medium- to long-term. However, these medium- to long-term impacts are generally not visible in the DAPRs, where DNSPs typically only publish investment plans for the minimum 5-year planning horizon (with the exception of Ausgrid and TasNetworks as mentioned above).

There is no natural "home" for publicly available strategic distribution network planning information

Different parts of the distribution planning framework touch on strategic planning (e.g. joint planning with TNSPs, the ISP, etc) and some DNSPs also voluntarily publish medium- to long-term planning information (e.g. in regulatory reset proposals), but the information is fragmented, inconsistent and difficult to piece together. There is no single place where DNSPs can provide this information in a more coherent manner (e.g. either as a separate publication or as part of the DAPR).

Strategic distribution planning processes may not be coordinated with other planning processes

There is currently no requirement for DNSPs to apply consistent inputs (e.g. forecasts) that are aligned with upstream processes such as the ISP, TNSP and state-based plans, as well as including planning outcomes from these processes. This may not be material over the shorter 5-year DAPR planning horizon, but can potentially lead to uncoordinated strategic planning over a longer-term horizon.

The 2026 ISP will only provide coarse guidance to DNSPs on the optimal investment pathway for the integration of CER and distributed generation/storage

For the first time, the 2026 ISP will consider investment planning of the distribution network in the optimisation process. However, as noted above, it will only provide rough investment costs at sub-regional level, e.g. $160m distribution network investment to increase CER hosting capacity in a specific sub-region by 250 MW. The investment cost would then need to be apportioned to the DNSPs in the sub-regions and then specific network projects would need to be identified to achieve the required CER hosting capacity.

There is currently no obvious venue where DNSPs would publish their detailed investment plans on a regular basis (except perhaps in regulatory reset proposals, but this is 5-yearly).

CER integration and LV demand flexibility are not yet integrated into the standard planning process

While most DNSPs have a CER integration and/or demand management strategy, these strategies are generally not integrated into the standard distribution network planning process.

As noted above, several DNSPs have created separate parallel planning processes exclusively for CER integration. However, it is unclear to what extent these two processes are reconciled as there is a disconnect between the forecasting approach and spatial granularity of the standard planning process (top down to primary distribution feeder level) and CER hosting capacity analysis (bottom up to distribution transformer level). A more comprehensive approach would integrate the planning process across the entire distribution network from sub-transmission down to LV end-use customer.

Moreover, planning for CER integration is not a requirement in the NER, so while some DNSPs (like SAPN) publish hosting capacity maps, this is purely voluntary and updates are at the whim of the DNSP. The ECA rule change request also pointed out that there are no requirements for the DAPR to report on CER integration, and so to the extent that DNSPs report on CER integration at all, it is typically only done during the 5-year regulatory reset proposal process.

Similarly, there is little consideration of demand flexibility at the LV level in the standard planning process. An exception is Energy Queensland, which have a large broad based and targeted demand management portfolio (including controllable assets at the LV level), and the use of this portfolio is integrated into Energy Queensland's standard peak demand planning process.

It is noted that demand management is incorporated into the standard planning process, but typically only to alleviate limitations identified at the HV level. In the typical demand management engagement strategy, DNSPs provide information on network limitations in the DAPR and then solicit proposals from external providers to offer non-network alternatives, i.e. DNSPs do not tend to actively search out non-network alternatives. Where applicable, these proposals are evaluated as part of the RIT-D process and procured if deemed to be the most efficient option. Most DNSPs do not procure demand management solutions as non-network alternatives, but of the few DNSPs that do (for example, AusNet and United Energy), the solutions tend to be for larger commercial and industrial loads directly connected to the HV network.

C Ampere Labs high-level review of the US Frameworks for Integrated Distribution System Planning

Ampere Labs

Integrated Distribution System Planning

Review of US Frameworks

September 2025

Introduction

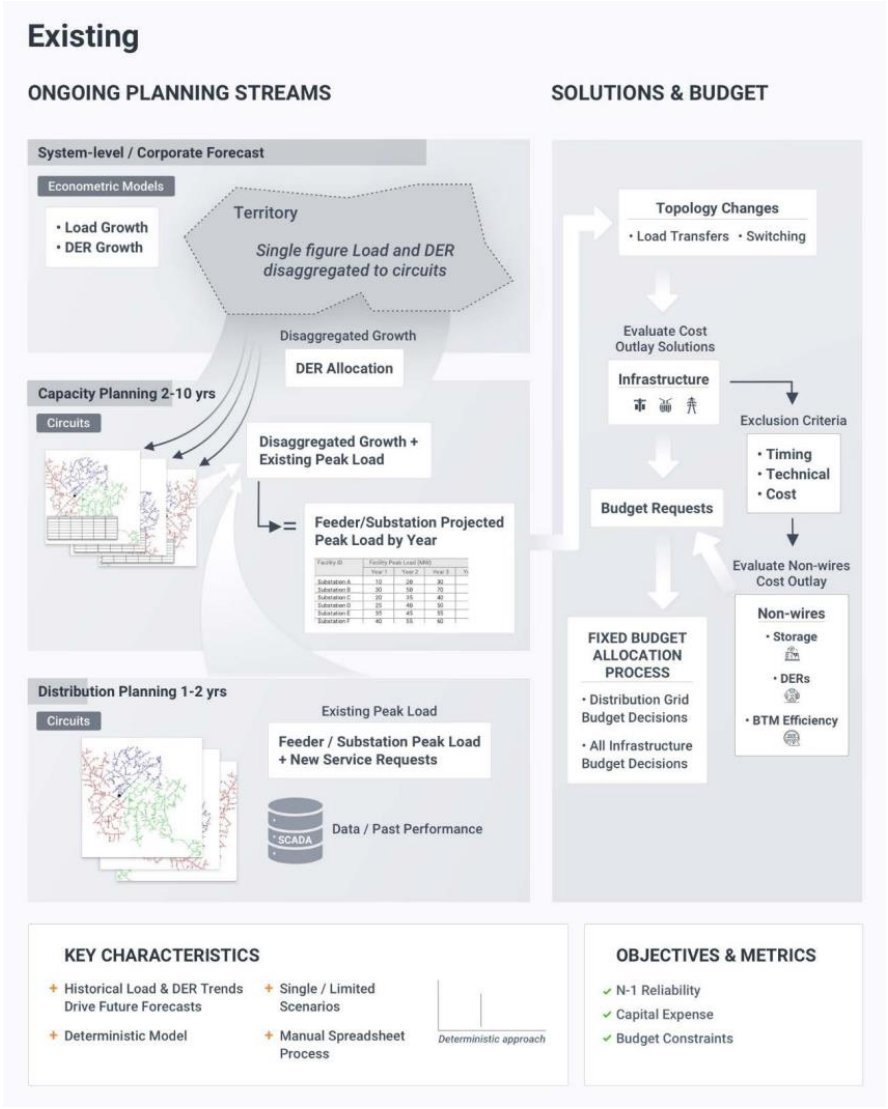
- This slide pack provides a high-level review of the integrated distribution system planning (IDSP) frameworks that have been applied in the United States, and their relevance to the integrated distribution system planning rule change (ERC0410), including:
  - What the IDSP framework is and how it evolved
  - How IDSP concepts are implemented in different US jurisdictions
  - Applicability of IDSP concepts to the NEM

.01
IDSP in the United States

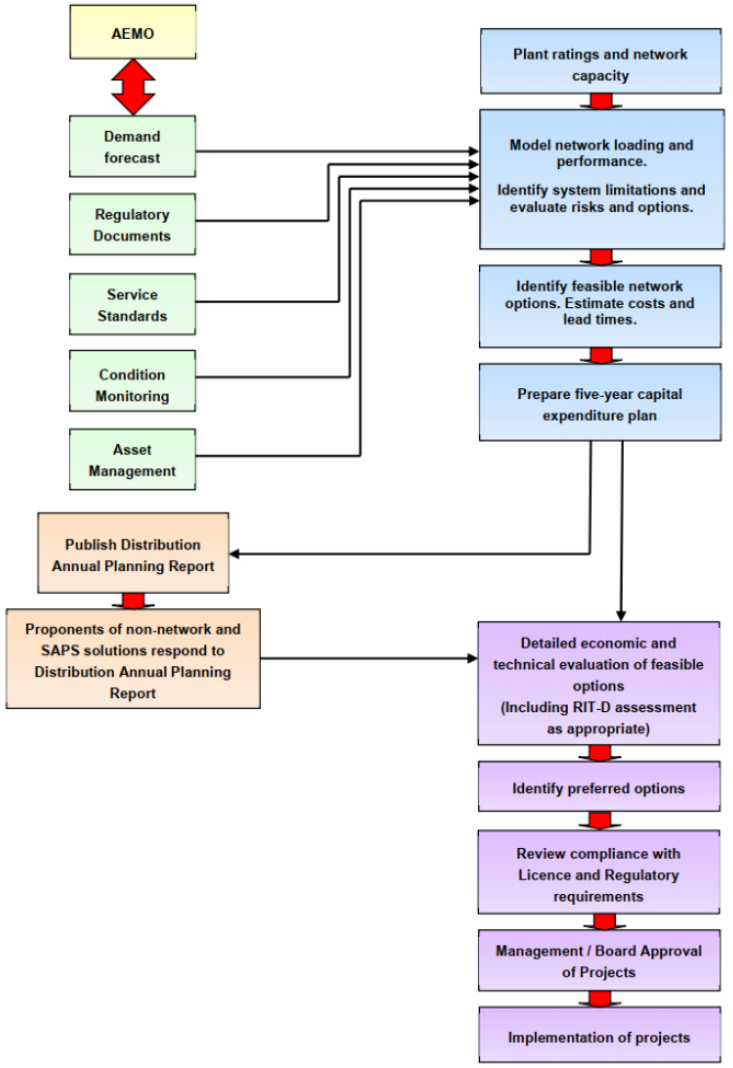
The “standard” planning process in the US and Australia are similar

Shared characteristics:

- Goal of planning is to ensure network reliability at least cost.
- Network centric approach with a focus on peak demand.
- Non-network options / non-wires alternatives are only evaluated after network options are identified (i.e. not integrated in the initial options analysis).



Source: NREL (2022)



Source: Jemena 2024 DAPR

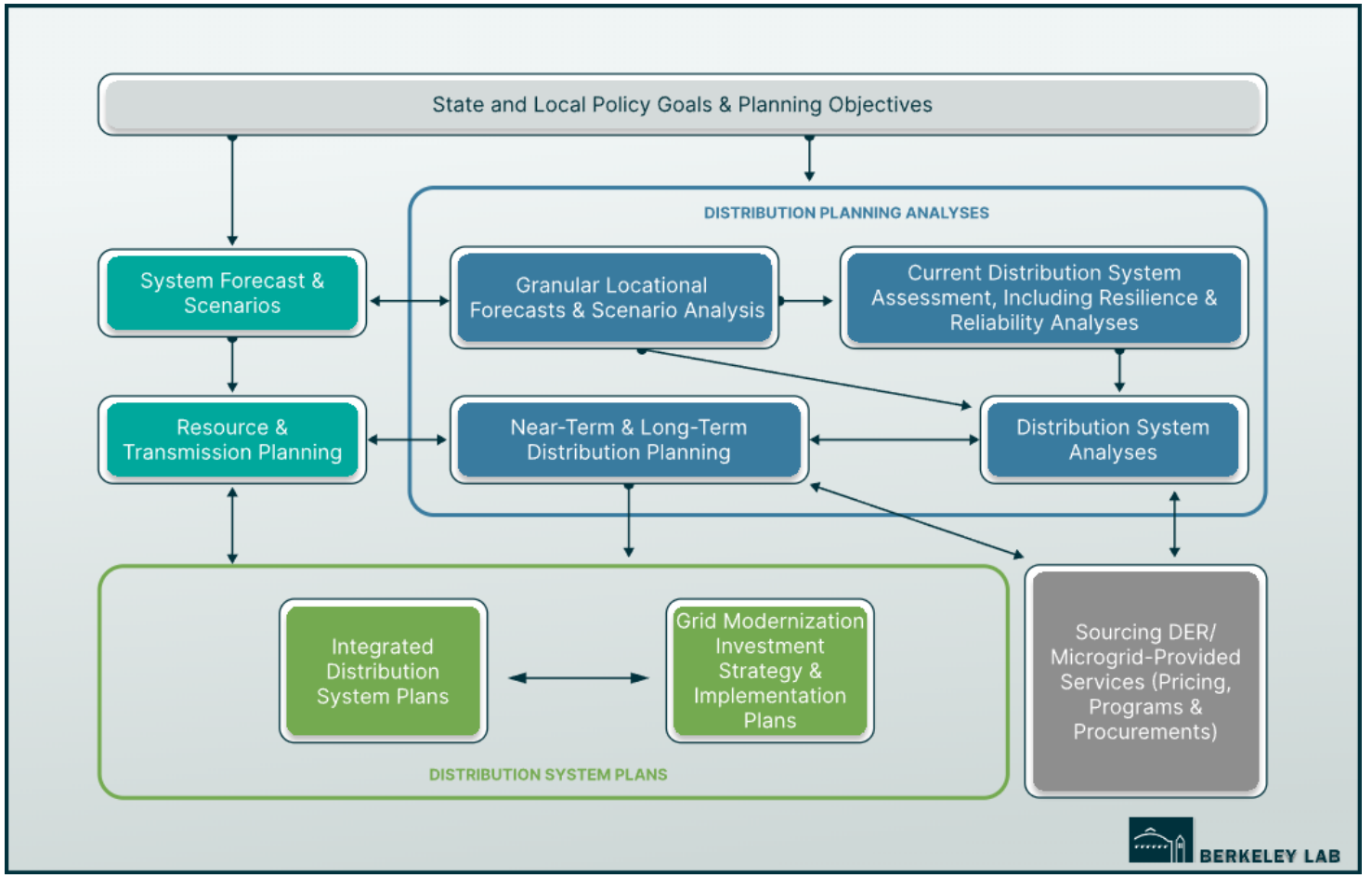
IDSP is essentially a set of interrelated ideas that the "standard" process does not cover

- Integrated distribution system planning (IDSP) is fundamentally an organised collection of different ideas that have been floating around in the distribution planning space (and network planning more broadly) over the last 20 years, but are not otherwise part of the "standard" planning process, for example:
  - **Integrated resource planning processes:** commonly used for bulk transmission and generation planning but extended to distribution network planning. This would typically follow a structure similar to the ISP, with elements including multiple future scenario analysis to manage uncertainty and risk, long time horizons (>15 years), rigorous stakeholder engagement and coordination with other planning processes.
  - **Multi-objective decision-making:** considering goals other than reliability and cost in the planning process, e.g. state government objectives such as resilience, affordability, equity, customer choice, DER integration, economic development, emissions reduction, etc.
  - **Effective DER utilisation:** applying hosting capacity, value of DER and locational benefits analyses to incorporate DER services into the planning process, as well as providing opportunities for customer empowerment (e.g. prosumer behaviour).
  - **Worst-performing circuits analysis and threat-based assessments:** systematically addressing the distribution feeders with the lowest reliability and feeders vulnerable to specific threats (e.g. natural disasters).

The IDSP concept has been formalised by two US national labs

- While instantiations of IDSP have been around in various guises over the years (e.g. Hawai'i Integrated Grid Planning), the IDSP concept has more recently been formalised by Lawrence Berkeley National Laboratory (Berkeley Lab) and Pacific Northwest National Laboratory (PNNL).

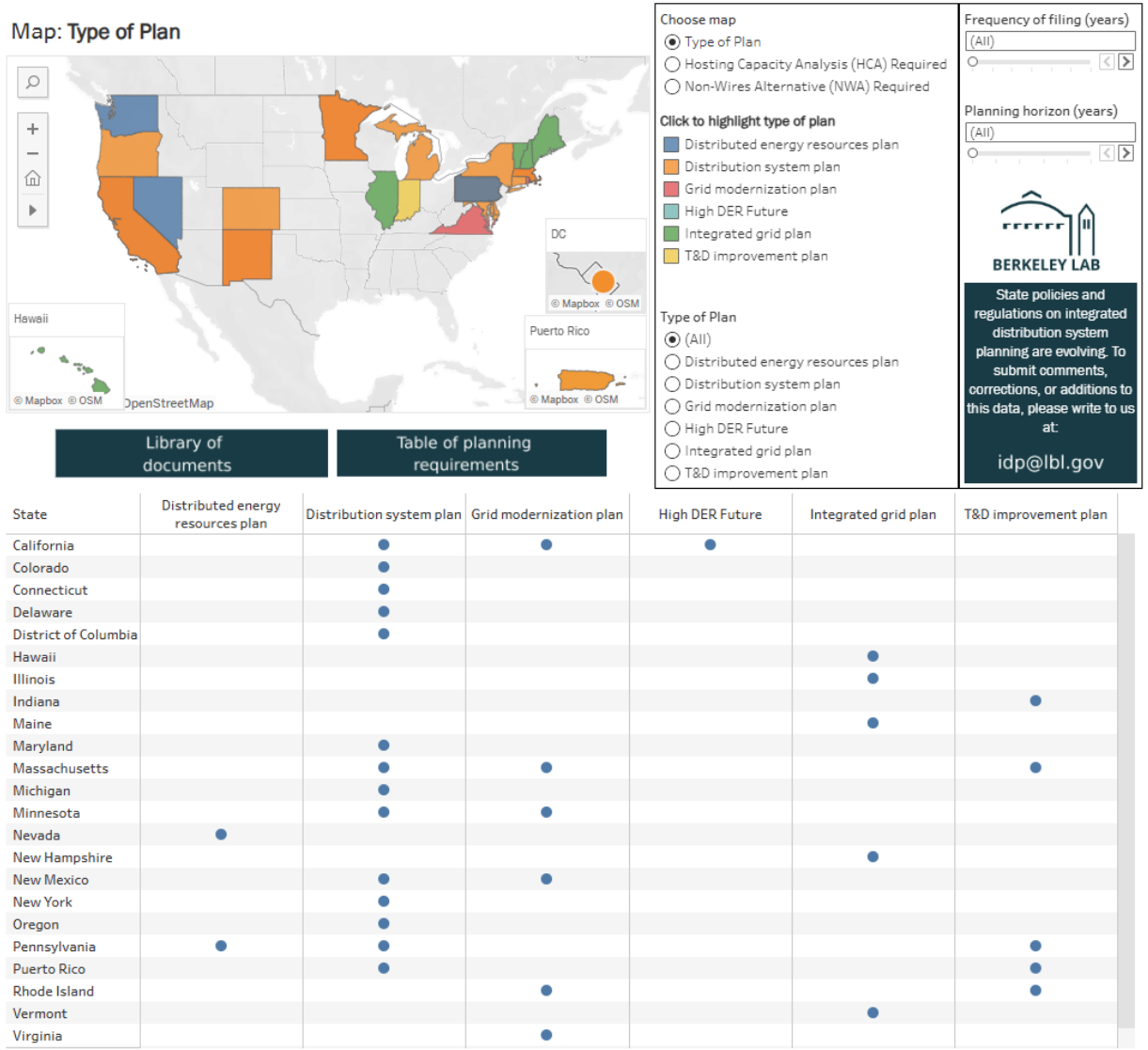
- In Berkeley Lab's version, IDSP is defined as a structured approach to long-term distribution grid investment that evaluates the **interdependencies between planning** for system resources (capacity expansion), transmission, distribution and operations.



Source: Berkeley Lab

But IDSP is still relatively new in practice

- IDSP is still a nascent concept in the US promoted by the US Department of Energy.
- Of the 50 US states and the District of Columbia, Berkeley Lab's mapping of state planning requirements indicates that only 23 jurisdictions have a requirement to publish some kind of distribution system, DER or grid modernisation / improvement plan.
- IDSP is also non-standard and implementations differ in each jurisdiction. The states with arguably the most advanced distribution planning requirements are:
  - California
  - Hawai'i
  - Minnesota
  - New York



State	Distributed energy resources plan	Distribution system plan	Grid modernization plan	High DER Future	Integrated grid plan	T&D improvement plan
California		●	●	●		
Colorado		●				
Connecticut		●				
Delaware		●				
District of Columbia		●				
Hawaii					●	
Illinois					●	
Indiana						●
Maine					●	
Maryland		●				
Massachusetts		●	●			●
Michigan		●				
Minnesota		●	●			
Nevada	●					
New Hampshire					●	
New Mexico		●	●			
New York		●				
Oregon		●				
Pennsylvania	●	●				●
Puerto Rico		●				●
Rhode Island			●			●
Vermont					●	
Virginia			●			

Source: Berkeley Lab

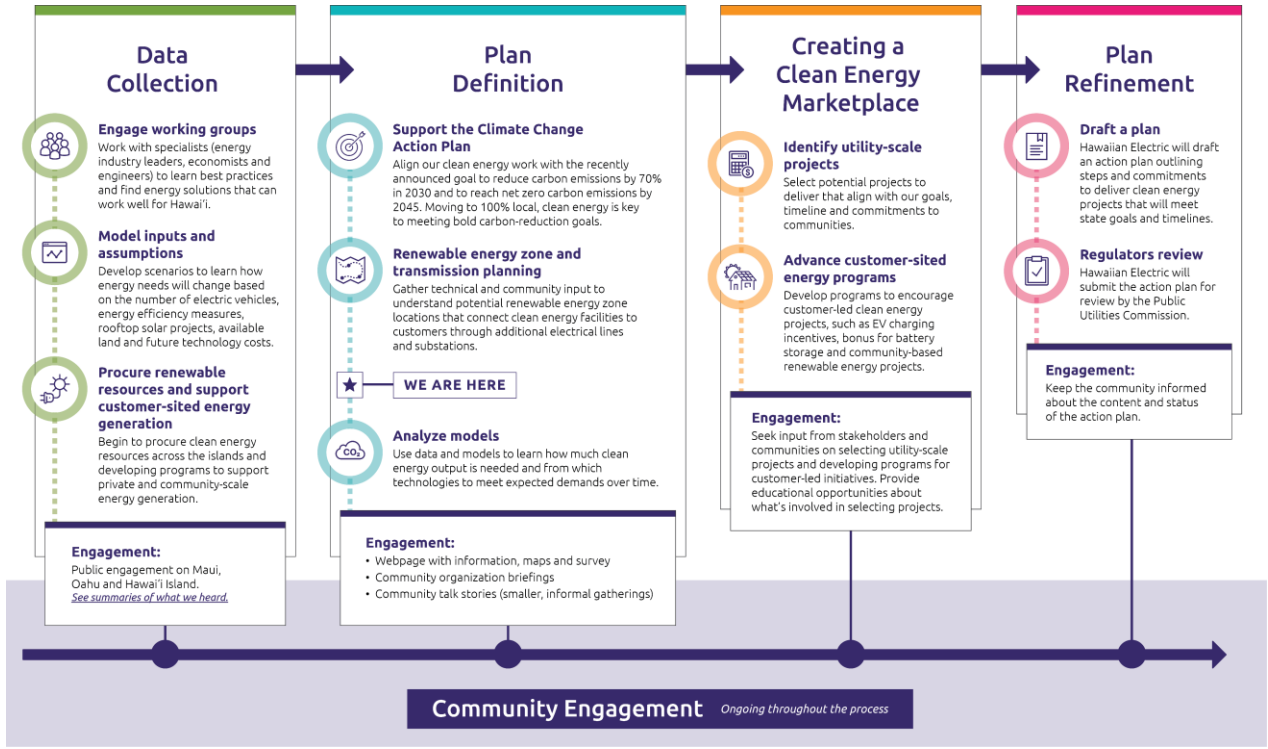
California

- In August 2014, the California Public Utilities Commission (CPUC) instituted CPUC rulemaking R.14-08-013 for investor-owned utilities (IOUs) to file Distribution Resources Plans that among other things established requirements for:
  - **Integration Capacity Analysis (ICA):** another name for DER hosting capacity analysis.
  - **Distribution Investment Deferral Framework (DIFD):** for deferring network CAPEX through the use of DER.
  - **Data Portals:** providing web-based geospatial maps accessible to the public of grid information such as network topology, DER capacity, ICA results, locational net benefit analysis results, etc.

- In October 2024, CPUC rulemaking 21-06-017 was made (applying to the IOUs PG&E, San Diego Gas & Electric Company and Southern California Edison) to further improve the existing distribution planning framework in preparation for a high DER future. Some improvements relevant to the IDSP rule change include:
  - Allow use of bottom-up forecasts to determine load growth
  - Extend distribution network planning horizon to a minimum of 10 years and a forecast horizon of 13 years (although full power flow analysis only needs to be done for the first 5 years)
  - Require use of scenario analysis for load and DER forecasting
  - Require the development of a prioritisation framework for projects identified in the planning horizon
  - Require the preparation of a load flexibility assessment in the planning process
  - Require the development of community engagement plan to address equity and metrics to track equity

Hawai'i

- Hawai'i Electric developed its inaugural Integrated Grid Plan (IGP) encompassing generation, transmission, distribution and operations, that was endorsed by the Public Utilities Commission in March 2024.
- The IGP process is structurally similar to equivalent ISP-like processes, with several rounds of stakeholder engagement and consultation at each stage of planning.
- The approach for distribution network needs assessments are outlined in Appendix I of the Grid Needs Assessment and Solution Evaluation Methodology report (November 2021), which includes standard distribution planning analyses, as well as DER hosting capacity analyses.
- The process for identifying and evaluating non-wires alternatives is similar to the RIT-D and DAPR processes in the NEM.



Source: Hawai'i Electric

Minnesota

- Beginning in 2018, Minnesota requires regulated distribution utilities to develop an Integrated Distribution Plan (IDP) and submit it to the Minnesota Public Utilities Commission every 2 years (on 1 November of odd numbered years).
  - Prior to submission, a utility must hold at least 1 stakeholder meeting covering DER forecasts and the 5-year investment plan.
  - After submission, IDPs are open for public comment.
- IDP filings are required to include:
  - Baseline data on the distribution system, budget and spending and DER
  - Hosting capacity and interconnection
  - DER futures analysis (scenario planning)
  - Long-term distribution system investment plan (5- and 10-year plans)
  - Non-wires Alternatives analysis
  - Transportation Electrification Plan
- Sample IDPs reviewed (Xcel Energy and Dakota Electric) indicate that the content of an IDP is similar to what is typically found in DAPR and revenue reset submissions.

New York

- In 2014, the New York Public Service Commission (PSC) launched the Reforming the Energy Vision proceeding (case 14-M-0101) to transition the distribution grid to a bidirectional system with increasing integration of DER and dynamic load management.
- The PSC defined a set of core functions, referred to as the Distribution System Platform, that utilities were required to provide, including advanced metering infrastructure, grid automation and DER management, **integrated system planning**, data and analytics, clean energy and decarbonisation and market services and innovation.
- Regulated utilities are required to file Distribution System Implementation Plans (DSIP) every 2 years to report on their progress towards developing the Distribution System Platform functions.
- As part of the integrated system planning function, utilities are required to enhance their distribution planning processes to better integrate and optimise DER (with a 5-year planning horizon), including:
  - Advanced forecasting of load and DER at higher temporal and spatial resolutions
  - Non-wires alternatives and beneficial locations for DER
  - DER hosting capacity analyses
  - DER interconnection management and transparency

.02
Applicability to the NEM

IDSP implementations are not that far from NEM practices

- The IDSP framework as set out by Berkeley Lab and PNNL can be seen as an aspirational platonic ideal.
- Actual implementations of integrated distribution planning in the US are actually more like evolutionary add-ons to the standard planning processes and not quite yet the comprehensive integrated framework described by Berkeley Lab.
- The actual IDSP implementations in the US are also not that far removed from current NEM DNSP practices when it comes to the substance that is different to "standard" planning processes (e.g. hosting capacity analyses, non-network options, bottom-up forecasting, etc), though perhaps the requirements are more explicit and transparently structured.
- For example, although there are no rule requirements for DNSPs to develop and publish DER hosting capacity analyses, most of the DNSPs do perform these analyses (partly as a way to justify expenditure via DER integration works). Some DNSPs (e.g. SAPN) also voluntarily publish hosting capacity maps.

However, there are some differences to current NEM practices

- Interesting features in IDSP implementations that are different to current standard NEM distribution planning practices include:
  - **Staged ISP-like process** with rounds of stakeholder engagement and consultation (e.g. methodologies, inputs, assumptions, scenarios, draft findings, etc) before final approval.
  - **Scenario analysis** with multiple future forecasts (instead of a single deterministic forecast for minimum and maximum demand that is common practice in NEM DNSPs).
  - **Longer time horizons**, e.g. ≥10-year planning horizons vs the 5-year planning horizons common in the NEM.
  - **Multi-criteria decision making frameworks** that include non techno-economic goals, e.g. equity, affordability, customer choice, DER and technology adoption, etc. This may have limited applicability in the NEM given the primacy of the NEO.
  - **Integrated transmission and distribution network planning**, although it is noted that unlike Australia, most US utilities are vertically integrated, thus making coordination of transmission and distribution planning more tractable. TasNetworks' integrated 10-year transmission and distribution annual planning report is a NEM example of this.

Thank you!

Please feel free to reach out for more information

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Abbreviations and defined terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CER	Consumer energy resources
Commission	See AEMC
CSIP-Aus	Common Smart Inverter Profile - Australia
DAPR	Distribution Annual Planning Report
DNSP	Distribution Network Service Provider
ECA	Energy Consumers Australia
ECMC	Energy and Climate Change Ministerial Council
ESOO	Electricity Statement of Opportunities
IASR	Inputs, Assumptions and Scenarios Report
IDSP	Integrated Distribution System Planning
IDSP RCR	Integrated Distribution System Planning rule change request
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NBI	Victorian Neighbourhood Battery Initiative
Proponent	The individual / organisation who submitted the rule change request to the Commission, see ECA
RIT-D	Regulatory investment test for distribution