THE HON CHRIS BOWEN MP
MINISTER FOR CLIMATE CHANGE AND ENERGY

[redacted]

Ms Anna Collyer
Chair
Australian Energy Market Commission
Level 15, 60 Castlereagh Street
SYDNEY NSW 2000

[redacted]

Dear Chair Anna

Please find attached two related rule change requests to amend the National Electricity Rules (NER). The requests seek to strengthen the NER to ensure that data centres and other large electricity loads make an appropriate contribution to the network costs they cause or accelerate, reducing the risk that these costs are recovered from existing electricity consumers.

The requests are consistent with the Australian Government's *Expectations of Data Centre and AI Infrastructure Developers* (Expectations) that data centre developers and operators support Australia's energy transition. At the 8 May 2026 Energy and Climate Change Ministerial Council meeting, Ministers welcomed the Expectations and agreed rule change requests be progressed to ensure data centre developers cover their share of transmission and distribution infrastructure costs. These requests have been developed in consultation with the states and territories.

I endorse these rule change requests and ask that the Australian Energy Market Commission progress with their initiation.

Yours sincerely

CHRIS BOWEN

Enc Rule Change Proposal

Request for standard rules

July 2026

Improving cost recovery arrangements in the National Electricity Market

Contents

1. Request to make a Rule

Name and address of person making the Rule

The Hon Chris Bowen MP

Minister for Climate Change and Energy

Parliament House

Canberra ACT 2600

2. Relevant background

Data centre growth

Data centres support the Australian economy by enabling firms to adopt productivity-enhancing technologies, access cloud services and data storage, and deploy tools which reduce costs and expand output. They also support government service delivery, defence and national security capabilities, and the scientific research infrastructure on which Australia's innovation system depends.

Australia already has an established and growing data centre industry, with more than 250 data centres in planning, development or operation. The surge in data centre investment is happening at the same time as we rapidly expand and transform our electricity systems to transition to net zero.

Data centre loads are expected to increase significantly over the next 5-10 years. Rapid and substantial growth in electricity demand from data centres and the deployment of artificial intelligence creates risks to our electricity system that need to be carefully managed, particularly given the uncertainty regarding the pace and scale of demand growth.

Data centre load growth is driving the need for new energy generation and network investments. The Australian Energy Market Operator's (AEMO) Step Change scenario in the 2026 Integrated System Plan forecasts data centre load will roughly triple by 2030, to 6% of electricity consumption of the National Electricity Market (NEM) with potential for larger growth. This forecasted energy demand is enough to power around 2.1 million homes.

International experience demonstrates that proactive policy settings are required to manage system risks and avoid unintended impacts on other energy users.

Expectations of data centres and AI infrastructure developers

On 23 March 2026, the Australian Government released its Expectations of data centres and AI infrastructure developers (Expectations). The Expectations aim to ensure investment in Australian digital infrastructure is consistent with our national interests. The Expectations make it clear that data centre growth should occur in a way that is sustainable for the energy system and fair for consumers. The Australian Government expects data centre and AI infrastructure operators to cover their share of transmission and distribution infrastructure costs and not place upward pressure on energy prices.

This view was endorsed by the Energy and Climate Change Ministerial Council on 8 May 2026 when Ministers welcomed the Australian Government's *Expectations of data centres and AI infrastructure developers* and agreed rule change requests be progressed to ensure data centre developers cover their share of transmission and distribution infrastructure costs.

Cost recovery framework

The existing cost-recovery framework for electricity network augmentation established in the National Electricity Rules (NER) was designed to appropriately allocate network costs to new and existing consumers on an efficient and equitable basis.

However, the nature, scale and speed of data centre connections represent a significant change that was not anticipated when the rules were initially set out. This change necessitates revisions to the existing regulatory framework so it can continue to efficiently and equitably allocate the significant costs associated with accommodating data centres on the electricity grid.

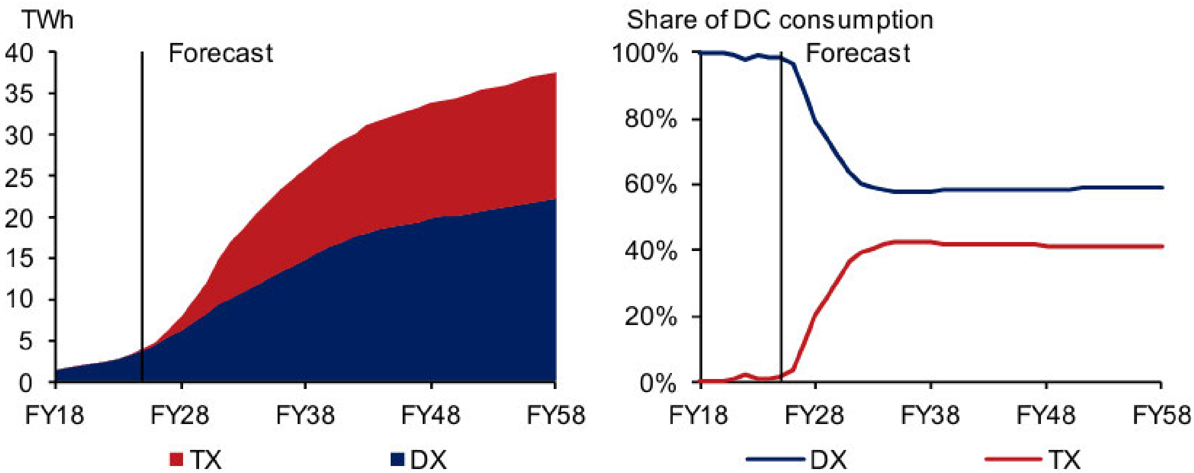
This rule change request asks the Australian Energy Market Commission (AEMC) to amend the network cost allocation rules under the NER and make changes required to ensure that other electricity customers are protected and that costs are appropriately allocated to new large loads.

The nature and scale of new large load connections is changing

AEMO's 2026 Integrated System Plan (ISP) included a forecast for data centres to approximately triple by 2030. Under the Step Change scenario, the 2026 ISP assumes that data centres will grow by around 25% annually to reach almost 10 per cent of underlying demand in the NEM by 2050, the equivalent of 20 per cent of today's total demand.[1]

The growth is in both the distribution and the transmission networks as seen in forecasts commissioned by AEMO that informed its ISP modelling (see Chart 1 below). Accordingly, this rule change seeks to address both distribution and transmission connections.

Chart 1: Data centre energy consumption by network connection (step change scenario)



Source: Oxford Economics Australia, *Data centre energy demand – Final report*, July 2025

The scale of capital involved in making these connections and providing adequate network capacity is significant.

[1] AEMO, *2026 Integrated System Plan (ISP)*, p44, https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp

In Victoria, the 2025 Victorian Annual Planning Report highlights the significant network augmentation that will be required to facilitate many of the proposed data centre connections AEMO has received. AEMO Victorian Planning received over 18 GW of large load connection enquiries that largely related to data centres in metropolitan Melbourne areas. Although many of these applications are not expected to proceed, new data centre load is expected to trigger significant augmentation costs due to existing network limitations in the Melbourne area.

For NSW, the 2025 Transmission Annual Planning Report (TAPR) highlights that data centre growth is a key driver of emerging transmission constraints, requiring major augmentation to maintain system reliability. The TAPR outlines a number of projects that are being assessed to accommodate the rapid growth of data centre loads. Transgrid's forecast, of data centre demand over the next 10 years increasing 20-fold relative to the 2024 TAPR, is indicative of the significant upstream augmentations that may be required.

This reinforces the need to ensure current cost recovery arrangements remain equitable and efficient as new large loads connect at both the distribution and transmission networks. Without changes to the NER, a potentially significant portion of this capital expenditure could be recovered from customers other than the large electricity customers that are driving the need for these investments. Given the unprecedented pace and scale of required investment, the impacts on electricity bills could be material and this would be contrary to the National Electricity Objective (NEO), as well as the Australian Government's expectations of data centres and principles articulated by various state and territory governments. While data centres also increase total consumption on the grid, helping to spread out existing fixed network costs across a wider consumer base does not take away from the need for data centres to efficiently and equitably contribute to the new network augmentation costs that their connection is triggering.

3. Statement of issue

The scenarios presented in both Rule Change Requests demonstrate that, under the current rules, there is a risk that network investments triggered by large load connections will be paid for in part by customers other than those who trigger the need for the expenditure.

To encourage efficient investment, risks should be borne by those who are best able to manage them. Small customers have no ability to manage costs associated with capital intensive network augmentations triggered by large loads, or the risk that such investments will be stranded if loads do not materialise in line with forecasts. Conversely, the current grid access regime limits the ability of large load proponents with high willingness-to-pay to contribute funding to network upgrade projects in return for connection capacity.

Addressing this set of challenges requires changes to the NER to align the connection incentives of large load proponents with the NEO’s commitment to economic efficiency.

Current rules allow connection costs to be shifted onto other customers

As data centre connections increase, networks supporting urban hubs are rapidly becoming constrained. For example, Transgrid has experienced an unprecedented increase in enquiries from connection proponents in Western Sydney and is now in advanced talks to connect 8 GW of data centre load to the grid. This is on par with the entire average daily demand for NSW between 7.5 GW and 10 GW. Plans for future network augmentation are accelerating to meet this growth, with the Project Assessment Draft Report (PADR) for Sydney Ring South noting that the project will be needed three years earlier than previously anticipated due to load growth associated with data centres. Accelerating this project is anticipated to cost an additional $1b in net present terms.

The timing of investment in other projects such as the New England REZ (estimated in the 2024 ISP as having a capex of $3.7 billion) may also need to be brought forward to meet growing demand from data centres. Without reforms such as those outlined in these rule change requests, these costs will be socialised across the consumer base at no clear consumer benefit.

Ensuring that large loads bear the costs and risks they impose on the network is essential to promote efficient investment in electricity supply infrastructure, consistent with the NEO.

There are elements of the current regulatory framework around connection cost recovery that are broadly working reasonably but could still be improved (e.g. how distribution connected data centres contribute to distribution augmentation costs),[2] while there are other components that need urgent attention (e.g. how either transmission or distribution connected data centres contribute to transmission augmentation costs).

Data centre connections may increase the risk of network asset stranding but have limited exposure to its costs

Data centre connections are distinct from historical large loads (e.g. smelters) in their unique combination of a) requesting optionality for very large allocations of firm grid capacity at the point of connection, while b) offering little certainty of future utilisation of that capacity. The degree of speculative and duplicative connection applications is a unique feature of the sector, reflecting the comparatively small footprint of data centre developments relative to their power needs and the relative ease with which connection applications can be lodged in order to secure capacity. The resulting lack of certainty about how much load will actually materialise increases the risk that network assets commissioned to support data centre demand may be underutilised or stranded if that demand fails to arrive.

There is precedent in the NER connection cost allocation rules to treat certain other distinct connection types separately where this is warranted. For example, real estate developers are treated differently in the distribution connection rules, recognising the very different circumstances of a real estate developer seeking to connect a new housing estate to the grid compared with a regular household seeking a new or modified connection.[3] Similarly,

[2] It is worth noting that distribution network cost recovery arrangements differ in NSW relative to other NEM jurisdictions. NSW has a contestable market for the delivery of distribution connection services and Chapter 5A of the NER, including the AER Connection Charge Guidelines, does not apply to these services.
[3] 'Real estate developer' is defined in NER, clause 5A.A.1 and treated differently to other retail customers in the Chapter 5A distribution connection rules.

data centres should be considered as a distinct and new material category of large loads that warrants a targeted and fit-for-purpose approach to that customer segment.

Under current rules, large loads are directly responsible for the upfront capital investment of their connection to the edge of the shared network (i.e. a dedicated connection asset or designated network asset). This means that the specific large load – not the network more broadly – is exposed to the financial risks of connection asset underutilisation or stranding if a load's demand fails to arrive as forecast.

Under current rules, large loads typically do *not* contribute capital to the 'upstream' augmentations needed to ensure their demand can be serviced from deeper within the shared transmission network (e.g. major shared network projects or REZ developments brought forward by increased demand forecasts). This means that the shared network – *not* the specific large load – is exposed to the financial costs of shared transmission network underutilisation or asset stranding if a load's demand fails to arrive as forecast. Improved cost recovery and prudential arrangements will have a beneficial impact by reducing the level of speculation in the sector and resulting uncertainty. This will reduce delays, inefficient investment and asset stranding risks, consistent with the NEO.

Taken together, these rule change requests are critical to strengthen cost recovery frameworks, prevent adverse impacts on electricity customers from being realised and advance the NEO.

ECMC requested review of cost recovery arrangements for data centres

On 19 December 2025, the Energy and Climate Change Ministerial Council asked officials to review cost recovery arrangements to ensure data centres cover network upgrade and connection costs.

Officials, including jurisdictional and market body representatives, undertook a program of work, including targeted consultations with network businesses, to better understand how the existing rules would allocate network augmentation costs for very large data centres and identify any gaps or issues arising.

As part of the consultation, several scenarios were considered and tested with network businesses. Through these scenarios, potential gaps in how the rules operate to allocate costs were identified along with proposed solutions.

The gaps and proposed solutions identified in these rule change requests cover both network augmentation cost recovery for large loads, and how large loads efficiently and equitably contribute to network and other costs which are recovered via network charges (e.g. jurisdictional schemes).

4. Structure of the Rule Change Requests

The gaps identified form the basis of two distinct but related rule change requests as set out below. Structuring the requests in this way will provide flexibility to enable the AEMC to consider the rule change requests concurrently or to separate out the second rule change request if required (e.g. to take additional time to deal with more complex issues). The issues outlined in Rule Change Request 1 are comparatively well-defined and may be able to be resolved more quickly. Issues outlined in Rule Change Request 2 may require more detailed analysis, additional information, or deeper consideration.

Given the rapid increase in transmission connected loads and the importance of protecting consumers from costs these loads trigger, or to which they should contribute, the preferred approach is for the two rule change requests to proceed concurrently. However, the submission of two distinct rule change requests will support flexibility in managing the requests, should that be required.

For administrative simplicity, a combined assessment of how the requested changes will contribute to achieving the NEO and mitigating impacts on consumers is set out at the end of each rule change request. Those sections clearly distinguish between elements of the assessment that relate to all the gaps and those which relate to one or more of the gaps.

5. Rule Change Request 1

Rule Change Request 1 addresses issues in the current NER which are comparatively well-defined and may be able to be resolved more quickly.

Identified issues are:

1. Pricing upstream transmission augmentations into distribution connections
2. Prudential arrangements for asset stranding
3. Safeguards for reallocating stranded assets
4. Collection, sharing and publication of information on large loads

5.A Nature and scope of issues, description of proposed rule and explanation of how the proposed rule would address the issue

Gap 1: Pricing upstream transmission augmentations into distribution connections

Scenario: A large load connects to a distribution network and triggers the need for upstream *transmission* augmentation to meet its demand.

Issue to be addressed: Rule 5.3AA requires some distribution network connection applicants to negotiate in good faith the charges they will pay in relation to augmentations to or extensions of transmission networks.

However, this provision does not apply to loads such as data centres.

Further, even if data centres were to fall under this rule, a requirement to negotiate in good faith is unlikely to be sufficiently robust to protect small customers from cross-subsidy risks. Currently, there is minimal incentive for distributors and connection applicants to ensure upstream costs are not socialised, especially as ensuring that all costs are adequately captured at the connection application stage involves challenges. Further, as there is competition to secure large loads, network businesses may also be incentivised to offer connections on terms that are not fully cost-reflective to secure investment. Current regulatory settings do not reliably prevent these costs from being passed through to customers over time. This is contrary to the NEO because it means investment decisions are not made on a transparent or efficient basis and risks are ultimately borne by those parties least able to manage them.

Description of proposed rule change: Rule 5.3AA should be amended to ensure that large loads are appropriately covered by this rule and costs are appropriately allocated. Amendments are likely to support the identification and pricing of transmission constraints and required augmentations in the connection charges paid by the connection applicant, rather than these costs being borne by the wider customer base.

The AEMC should also consider whether a requirement to negotiate charges in good faith under clause 5.3AA(f)(3)(i) is sufficiently robust to ensure upstream costs are accurately estimated and reflected in distribution level connection costs to avoid the risk of cross-subsidy, including a mechanism to ensure actual costs are recovered from large loads if they exceed costs forecast at the time the connection agreement is finalised. Similar to the proposal below on prudential arrangements, this could be based on large loads above a specified nameplate capacity.

Gap 2: Prudential arrangements for asset stranding

Scenario: A data centre contracts a certain hosting capacity in a constrained part of the network, triggering an augmentation that the data centre agrees to pay for over time. However, the load ramps slower than forecast or the project fails commercially resulting in the network provider being short and potentially holding a stranded asset.

Issue to be addressed: Where expected demand does not eventuate and assets are stranded, there is a risk that costs will be recovered from the existing consumer base. The NER provides optional tools to manage stranding risk through prudential requirements in connection agreements such as, capital contributions and prepayments. However, there is no obligation for distribution or transmission providers to use these arrangements, and the rules provide more detail on potential arrangements for distributors than is provided for transmission providers (see rules 6.21 and 6A.28). Further, these arrangements may require enforcement by the network provider and there may be limited incentive for them to undertake enforcement action.

Description of proposed rule change: The prudential arrangements in the NER should be strengthened and aligned. Rule 6A.28 should be amended to set out the types of arrangements to be used by transmission network service providers (TNSPs) to manage stranded asset risk, similar to the approach in rule 6.21 for distribution network service providers (DNSPs).

Network service providers should be required to implement specific prudential arrangements, including pre-payment or provision of bank guarantees, for connections above a certain threshold (for instance, connections above a specified nameplate capacity or requiring capital expenditure above a specified amount).

Arrangements that do not require legal action to enforce them, such as pre-payment or bank guarantees, are considered preferable. If legal action does need to be taken to enforce prudential arrangements, network service providers should be compelled to take legal action rather than recovering costs from other customers (which would be contrary to the NEO).

Consideration should also be given, where pre-payments are used, to the use of complementary mechanisms to ensure any difference between forecast and actual expenditure is not recovered from other consumers. This is important given the degree to which actual costs typically exceed forecasts, the scale of transmission augmentations needed in response to rapid large load growth (and hence the dollar value of potential exceedances) and the rate at which input costs continue to rise. Failure to prevent cost exceedances being recovered from small consumers would be contrary to the NEO.

At the distribution level, the standard place to include these requirements would be in the connection policies of each distribution network which are normally only amended (and approved by the AER) at the time of the five yearly distribution determinations. However, given the urgency to have these arrangements in place soon and not wait until the next regulatory period, these requirements should either be placed directly in the rules, or the rules should require distribution networks to revise their connection policies mid-regulatory period.

Gap 3: Safeguards for reallocating the costs of network assets

Scenario: As above, a data centre contracts a certain hosting capacity, but the expected demand does not eventuate, meaning the cost of a network asset built to support the connection is not fully recovered from the data centre customer.

Issue to be addressed: In certain circumstances, a network service provider may seek to roll part of the value of a network asset that originally formed part of a user-specific negotiated service into its regulated asset base. This is enabled by clause 6A.19.2(8) of the NER for transmission and Schedule 6.2.1(e)(8) for distribution. This allows part of the cost of the asset to be recovered from the broader electricity customer base.

The rules place three safeguards on this roll-in process. Assets can only be reallocated where:

- they will provide shared services; and
- capital costs have not yet been recovered; and
- the AER approves the roll in as part of the determination process.

These safeguards provide strong, but not complete, assurance that assets originally built to service very large loads will not ultimately be paid for by existing electricity consumers.

Description of proposed rule change: Given the large number and value of network assets expected to be built as part of negotiated services provided to data centre customers, the NER should provide stronger protections to ensure costs and risks of network assets are appropriately allocated between customers.

Limiting the opportunities to reallocate certain customer-specific assets would provide a strong financial incentive for network providers to ensure that assets supporting specific customer connections are recovered from those customers in all conceivable scenarios – including where the customer's expected load does not eventuate – through the use of appropriate prudential arrangements. Limiting the ability to reallocate assets will help ensure that the financial risk of asset stranding is not shared with the broader customer base and that this risk is instead managed by those who are best placed to manage it – being the network service provider and the connecting customer.

The limitation could be implemented through changes to clause 6A.19.2(8) and Schedule 6.2.1(e)(8) to further restrict reallocation of specified assets. Alternatively, the AER could be given further guidance in how it should consider roll-in applications from network service providers, and NSPs could be given more specific obligations about the information they need to supply AER to support its assessment of whether rolling the capital expenditure into the regulated asset base is appropriate.

The rules should include a classification for the customer specific assets that would be subject to the enhanced protections. For example, a capex threshold, specified asset types or use cases could be considered.

Gap 4: Collection, sharing and publication of information on large loads

Issue to be addressed: TNSPs are required to establish, maintain and publish a register of large generator connections on their websites (i.e. with nameplate rating of 30MW or greater) and large bidirectional units (above 5MW). This register enhances transparency regarding new generator connections, listing location, technology, capacity and impact assessments (clause 5.18A.2). There is no equivalent register for large loads.

Description of proposed rule change: The requirement under clause 5.18A.2 should be extended to loads over a specified size.

Specifically, it should require NSPs to regularly collect and input information about large loads into a new public register hosted by AEMO. The rules should provide that:

- Both DNSPs and TNSPs are required to provide information on all <u>prospective and existing</u> loads in their network areas with a rated capacity of 5 MW or more (with all connection points for a given facility or premise being aggregated for the purpose of this threshold), consistent with the approach to large bidirectional units.

- Information provided on each prospective load must include: name of proponent/applicant (and originating proponent if the proponent/applicant is acting on behalf of a third party); name of site; name of site owner; ANZSIC code (subdivision level); requested connection capacity and voltage level; name of relevant bulk supply point(s); requested and expected ramping rate and timeframe; current stage of the connection process (e.g., pre-enquiry, enquiry, application, offer, agreement, energised); date of initial and most recent contact, enquiry and application (and withdrawal of application where relevant); current treatment of prospective load for purposes of load forecasts and planning by the NSP (e.g., proposed, anticipated, committed, operational).
- Information provided on each existing load must include: name of operator and owner; name of site; name of site owner; ANZSIC code (subdivision level); connection capacity and voltage level; name of relevant bulk supply point(s); expected and observed ramping rate and timeframe; date of energisation of connection.

Setting the threshold at 5MW would be consistent with the approach to large bidirectional units and ensure that data is available in relation to smaller loads as well as larger loads. Cumulative impacts of smaller loads can be significant (as noted in AEMO's recent General Power System Risk Review). Setting the threshold at 5MW rather than 30MW also helps manage, and provide insights regarding, boundary effects that could arise if developers seek to avoid regulatory requirements that apply to loads of 30MW or greater.

There is precedent for publishing information on prospective developments. The AEMO Generation Information, required under NER clause 3.7F, is updated at least every three months and includes information on proposed generation and storage developments. Clause 3.7F(g) requires TNSPs to provide AEMO key connection information on connection enquiries and applications, and this information is published by AEMO. The NER defines key connection information as: the name, ABN, ACN of the proponent; the type of plant; site location or preferred site location; maximum power generation of the whole plant; forecast completion date of the proposed connection; and the technology of each relevant generating or bidirectional unit.[4]

The register would support efficient planning, pre-investment and investment decisions. It would allow NSPs to identify speculative, duplicative and dormant applications and to adjust load forecasts and efficiently allocate finite connection resources. It would allow NSPs and AEMO to understand expected increases in demand over time and avoid unnecessary or premature network investments, including by allowing annual ramp rates (and not just rated capacities) to be considered. It would support reliability and system security by allowing network planning and investment decisions made by NSPs, AEMO and others to be made based on accurate forecasts. This would mitigate costs and risks for consumers, consistent with the NEO.

In considering the creation of such a register, issues of confidentiality and competition are likely to arise. The rules will need to include clear requirements regarding information provision by connection applicants and NSPs. They should expressly prevent NSPs giving contractual undertakings to connection applicants that would prevent them from including information in the register or sharing information required by AER or AEMO to perform a regulatory or market support function.

5.B Contribution to the NEO

Rule Change Request 1 will strengthen existing cost recovery mechanisms against an increasing risk of network asset stranding and address inconsistent treatment of upstream network impacts between transmission-connected and distribution-connected large loads. These changes will improve locational cost signals for new connections and ensure that location-specific connection costs are not spread onto other network customers as bill increases, risking cost inefficiency and raising barriers to emission reductions via electrification.

[4] See NEM Generation Information and Key Connection Information publications at AEMO – Generation Information.

The NEO is:

> "to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:
>
> a) price, quality, safety, reliability and security of supply of electricity; and
>
> b) the reliability, safety and security of the national electricity system; and
>
> c) the achievement of targets set by a participating jurisdiction –
>
>   i. for reducing Australia's greenhouse gas emissions; or
>
>   ii. that are likely to contribute to reducing Australia's greenhouse gas emissions."

The anticipated level of data centre development is expected to result in demand for electricity exceeding currently available generation and network capacity, requiring the deployment of capital to augment networks and increase hosting capacity. Under current rules, costs for those augmentations can be shifted away from new connections and onto the existing network customer base.

The scenarios presented in both Rule Change Requests demonstrate that, under the current rules, there is a significant risk that costs for network investments triggered by new large load connections will be passed through to customers with no responsibility for triggering that expenditure. This risk of cost shifting has consequences which are contrary to parts a) and c) of the NEO:

- Future demand of large data centre loads remains uncertain, increasing the risk of asset stranding for new network assets developed to accommodate future load growth. Stranding of underutilised assets reduces the productive efficiency of the network as a whole, contrary to part (a) of the NEO.
- Shifting induced upstream transmission augmentation costs onto the broader network cost-base weakens the locational price signal to developers at the point of connection. This reduces the incentive for developers to connect at locations with

lower upstream augmentation costs, reducing allocative price efficiency contrary to part (a) of the NEO.

- Significant growth in electrification is needed to meet Australia's jurisdictional emission reduction commitments, as specified in the AEMC's Emissions Targets Statement. Electrification is sensitive to electricity costs, which may increase for existing users if the cost of load-triggered upstream transmission augmentations is socialised. A slowdown in electrification triggered by shared costs rising as a result of large load growth would risk increased emissions, contrary to part (c) of the NEO).

Efficient investment requires that risks are borne by those best able to manage them. Existing network customers have no ability to manage costs of upstream augmentations triggered by other connections, or to manage their exposure to costs of asset stranding if large loads demand forecasts fail to eventuate. The rule changes proposed here would contribute to the achievement of the NEO by ensuring that Australian households and businesses do not bear the cost of network augmentations from which they do not benefit.

5.C Expected benefits, costs, and impacts

Expected benefits

The rules changes proposed would provide broader system benefits by improving the incentives for large loads to connect at locations with lower upstream congestion impacts.

These benefits include:

- Reduced system network augmentation costs from a shift in development of new loads toward lower-impact locations, delivered by sharper locational incentives for connection at locations with less need for upstream augmentation and supported by improved access to information regarding other existing or potential loads [Gap 1, 4]. Improved transparency and locational signalling may reduce uncertainty, support efficient connection processes and enhance speed to market which is said to be a key consideration for the data centre sector.

- Increased capacity to accommodate other important electricity loads within congested networks e.g. housing. (Housing developments in some metropolitan areas are incurring high costs to augment network capacity where available headroom has been exhausted. Experience in other jurisdictions such as Ireland highlights the potential for rapid large load growth to crowd out housing.[5])
- Improved productive efficiency via a lower risk of network asset stranding, delivered by better alignment of incentives for networks and load proponents to manage this risk [Gap 2, 3].
- Increased viability of electrification to deliver emissions reductions, delivered by lower electricity costs increasing the favourability of emissions-displacing electrification [Gap 1, 2, 3].
- Reduced upstream congestion at major load centres may improve the ability to deliver emissions reduction via electrification of existing industries (e.g. industrial heat electrification; vehicle fleet electrification).

Expected costs

While the proposed rules changes may entail some costs due to developers of large loads needing to develop greater understanding of the upstream consequences of connection at a given location, net cost impacts are expected to be small for the reasons set out below:

- While the requested amendments may increase administrative cost for networks to collect and share information on connecting large loads [Gap 4], networks are already expending resources to understand and manage connection queues. The efficiency of this process is hampered by inadequate access to data.
- The proposed amendments may increase costs for connection proponents to understand upstream transmission impacts on connection cost when identifying connection options [Gap 1]. However, increased transparency will improve the

[5] 'Scandal hiding in plain sight' as data centres are risk to new homes accessing power, 3 May 2025

efficiency of decision making relative to current processes and mitigate the risk of delays when upstream augmentations are needed before large loads can energise.

- Cost to develop new frameworks and policies for cost recovery of large loads identified as carrying higher risks of asset stranding. Such costs are expected to be outweighed by the benefit of improved visibility, reduced uncertainty and more efficient connection processes. For example, in Ohio, use of stronger prudential requirements halved the connection application queue. Resulting in much more efficient processes for connecting well advanced connection applications.[6]

Expected impacts

These rule changes will ensure that existing electricity consumers' costs will be lower with a reduced prospect of future increases. This is achieved by shifting the financial burden of upstream network augmentations toward a 'causer pays' methodology [Gap 1] and reducing exposure to stranded asset costs [Gap 2, 3].

Where the connection of new large loads triggers the need for upstream network augmentations, those large loads will carry an increased share of augmentation costs [Gap 1]. These cost contributions may also shift toward up-front contributions rather than long-term annuity payments if networks require accelerated cost recovery to manage greater exposure to stranded asset risks [Gap 2]. Where networks are unable to manage stranded asset risk effectively, they may face liabilities for unrecoverable user-specific asset costs [Gap 3]. It is anticipated that networks will manage this risk through greater requirements for up-front capital contributions or credit guarantees, but some risk may remain.

In return for exposure to a greater share of induced costs, large load developers will receive improved visibility into the network connection pipeline [Gap 4], reducing the uncertainties of network congestion in development.

[6] National Association of Regulatory Utility Commissioners, Large Load Tariffs and Load Forecasting: Reducing Uncertainty in an Era of Load Growth, April 2026

6. Rule Change Request 2

This rule change request addresses cost recovery issues in the NER which may require more detailed analysis, additional information, or deeper consideration than those outlined in Rule Change Request 1.

Identified issues are:

5. Barriers to the use of funded augmentations
6. Jurisdictional scheme costs can only be recovered from distribution connected customers
7. Guidelines for transmission connection policies and charges

6.A Nature and scope of issues, description of proposed rule and explanation of how the proposed rule would address the issue

Gap 5: Barriers to the use of funded augmentations

Scenario: Large loads, particularly when geographically clustered, can drive the need for significant shared transmission augmentations.

Issue to be addressed: TNSPs have discretion to negotiate with such customers to deliver these upgrades as funded augmentations under rule 5.18, whereby the identified customer or customers fully cover the design, construction and ongoing operation and maintenance costs, thereby insulating other customers from these expenses.

However, it is understood that this mechanism has rarely been used. Rule 5.18 itself is relatively limited in scope and primarily concerned with giving notice of the proposal to other parties. There is potential for funded augmentations to be used more extensively, especially in the context of clustered loads, for example to support data centre precincts, or where a number of data centre proposals trigger the need for a network upgrade. However, the rules currently provide limited guidance and there is a potential 'first-mover' disadvantage where an asset could be paid for by the first connection but used by subsequent connections. This may deter connection applicants and networks from wanting to pursue this model.

Description of proposed rule change: Rule 5.18 should be amended, and consideration given to amending Chapter 5 more broadly, to ensure the rules for funded augmentations and related guidance are fit for purpose and support greater use of funded augmentations, particularly for clustered connections.

Firstly, the definition of funded augmentation in the rules should be amended to enable funded augmentations to apply in a wider set of circumstances. The current definition is restricted to circumstances where the transmission network "is not entitled to receive a charge pursuant to Chapter 6A". This definition is ambiguous and overly restrictive.[7] It is proposed this be amended to encompass circumstances where the augmentation was not included in the transmission network's current revenue determination.

Secondly, reforming the rules to be fit of purpose will necessarily include consideration of how the first-mover issue can be resolved. This could include allowing for payment into a funding pool that is dynamically adjusted over time as new users come to share the asset, or a similar method to compensate a first-mover who supports subsequent connections. This could leverage approaches already available under clause 5A.E.1(d) for connection assets built on the distribution network. Under this approach, a customer can be refunded part of the cost of a dedicated connection asset it has wholly funded where that asset is subsequently used by other customers within 7 years of its construction or installation. This is commonly referred to as a 'pioneer scheme' approach.

It is noted that Schedule 5.11(6) provides some guidance on adjusting pricing as assets come to be used by new users, but this may not be adequate and could be strengthened. Guidelines to support networks in deploying this approach could also be considered to

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[7] The current language around "entitled" is ambiguous and overly restrictive because transmission network service providers are not bound to simply follow the projects they have been funded for in a revenue determination. The capex forecast in the revenue determination is effectively a "bucket of money" and the TNSP is meant to respond to changing circumstances during the regulatory period and adjust what projects it pursues. So even if the augmentation was not included in the capex forecast in the revenue determination, the TNSP would still be "entitled" to fund the project from its current capex forecast so long as the project provided prescribed transmission services. Even if the augmentation meant the TNSP overspent its total capex forecast, it would still be "entitled" to roll a portion of that capex into its regulatory asset base, subject to the AER's ex-post prudency test.

ensure that assets are appropriately sized to achieve efficient outcomes and costs fairly allocated.

Consideration should be given to whether similar concepts should be extended to augmentation of the shared distribution network, not just the shared transmission network.

Gap 6: Jurisdictional scheme costs can only be recovered from distribution connected customers

Scenario: A large load connects to the transmission network and hence is not liable for jurisdictional scheme costs under the NER.

Issue to be addressed: Jurisdictional schemes originally were used to recover the cost of solar feed-in tariffs, but their use has expanded in recent years. For example, jurisdictional schemes are used to fund the Orderly Exit Mechanism Framework (OEMF), and jurisdictional schemes are used in NSW to recover costs associated with the NSW Electricity Infrastructure Roadmap and Climate Change Fund.

Clause 6.18.7A of the NER enables the cost of jurisdictional schemes to be recovered via DNSPs however there is no corresponding provision for TNSPs. This means that large transmission connected customers do not contribute to funding schemes.

Historically, with the majority of customers being distribution connected, this was not a material issue. However, with the increase in costs being recovered via jurisdictional schemes, combined with the increase in transmission connected loads, equity concerns will grow if the framework continues to allow jurisdictional scheme costs to be recovered solely from distribution connected customers. This would be contrary to the NEO, not only because smaller customers would bear costs that large customers do not (exacerbating existing inequities, particularly where jurisdictional scheme costs rise due to large load connections) but also because the current arrangements may distort investment decisions, incentivising connections to transmission networks in order to avoid charges that are imposed on customers connecting to distribution networks. This distortionary effect will not support optimally efficient investment decisions and should be removed.

Enabling jurisdictional scheme costs to be recovered at the transmission level may also require changes to transmission service definitions or the addition of another transmission service in the NER.

Amending the NER to enable jurisdictional scheme costs to be recovered from transmission connected customers would benefit all jurisdictions and market participants by providing a consistent NEM-wide cost recovery framework. For example, it would enable the costs of multi-state schemes, such as the OEMF, to be recovered more equitably from transmission and distribution connected customers.

It would also avoid the need for states to derogate, to enable transmission-level cost recovery for jurisdiction-specific schemes. Given the gaps in the current NER framework, South Australia needed to derogate from the NER in order to enable transmission level cost recovery for its Firm Energy Reliability Mechanism[8]. This highlights the need for action to address this gap by creating a consistent and equitable framework, rather than leaving it to the states to derogate from the NER to avoid inequitable outcomes.

Description of proposed rule change: A new rule should be included in Chapter 6A, analogous to clause 6.18.7A, to facilitate pass through of jurisdictional scheme amounts to TNSPs and their customers.

The proposed rule should address the following considerations:

- Allow for jurisdictions to allocate costs to particular classes of connection (e.g. to exclude DNSPs to avoid "double dipping") and/or for costs to be recovered via certain tariff structures (e.g. $/MW capacity charges) – this could be done by requiring that any jurisdictional scheme charges must comply with all applicable regulatory instruments including jurisdictional legislative and regulatory instruments. This would be analogous to the distribution pricing principle in Rule 6.18.5(j) which

[8] National Electricity (South Australia) (Firm Energy Reliability and Orderly Exit Management) Regulations 2025

enables jurisdictions to guide the recovery of distribution jurisdictional scheme costs.[9]

- Enable jurisdictional scheme costs from one jurisdiction to be isolated and not recovered from customers in another jurisdiction (to prevent inter-jurisdictional cross subsidisation of scheme costs). For example, a NSW transmission level jurisdictional scheme would impose costs on ACT customers (since they are serviced by Transgrid) unless the scheme provided to the contrary. This can be determined by the jurisdictions on a case-by-case basis.
- Enable the AER to determine whether schemes proposed to it by jurisdictions meet the criteria set out in the NER (i.e. this would be analogous to the Rule 6.18.7A(f)-(x) process set out in the distribution rules).
- For the avoidance of doubt, the same scheme could be both a distribution and transmission jurisdictional scheme, recovered across both distribution and transmission connected loads. Where this occurs, the AER should have an oversight role to ensure the same scheme costs are not recovered more than once.
- The intention is that existing distribution jurisdictional schemes will not automatically become transmission jurisdictional schemes, but it should be administratively simple for jurisdictions to nominate a distribution scheme to become a transmission scheme if they so choose. A jurisdiction could be required to inform the AER if the jurisdiction develops a transmission jurisdictional scheme. If the AER determines that the scheme meets the relevant criteria set out in the NER, the AER could then publish details of the scheme (consistent with current practice).

The creation of transmission jurisdictional scheme amounts will necessitate consideration of how these scheme amounts should be recovered via transmission charges imposed on loads that are directly connected to a transmission network.

[9] For the avoidance of doubt, the list of 'applicable regulatory instruments' in the NER Chapter 10 Glossary should be updated to include the *Electricity Infrastructure Investment Act 2020 (NSW)*.

The four service charge categories in the NER do not allow for equitable jurisdictional scheme cost recovery from large loads. The four categories include: entry connection services, exit connection services, transmission common services and transmission use of system services (clause 6A.23.4(a)).

A new service charge category may be required for jurisdictional schemes to pass through costs to directly connected TNSP customers, including large loads. The purpose of the category is to enable TNSPs to recover jurisdictional scheme amounts on a cost reflective basis from large directly connected customers in proportion to volume of electricity consumed and/or requested capacity. (The volume of requested capacity, in addition to electricity consumed, is an important consideration given that large loads often involve high connection capacities and low MWh consumption in the initial post-energisation period. If charges are based only on consumption, this creates a risk of socialising costs – noting that augmentation expenditure will be influenced by requested capacities.)

Further, this new transmission service category may need to be a required transmission service that applies to both prescribed transmission service and negotiated transmission service customers. This is to avoid a distortion in cost recovery that would occur if directly connected transmission customers could avoid contributing to jurisdictional scheme cost recovery by negotiating a negotiated transmission service.

The intent is costs recovered under the jurisdictional scheme would not duplicate cost recovery under any other mechanism.

Gap 7: Guidelines for transmission connection policies and charges

Scenario: A large load connection to the transmission network is provided as a negotiated service and that load subsequently triggers the need for deep upstream augmentation.

Issue to be addressed: Clause 5A.E.1 of the NER sets out connection charge principles and clause 5A.E.3 requires the Australian Energy Regulator to develop and publish connection charge guidelines for the development of connection policies by DNSPs.

There is no consolidated guidance for transmission connection pricing in the NER.

Outside Victoria, clause 5.2A of the NER together with Schedule 5.11 specify negotiating principles to be applied by TNSPs. In Victoria, similar principles are applied under *Negotiated Transmission Service Criteria* published by the AER that apply to specified TNSPs and are largely aligned with Schedule 5.11.[10]

The distribution connection charge guidelines set out much more explicit requirements on distributors. In particular, the distribution guidelines require distributors to use unit rates to calculate and allocate the cost of shared network assets to new customers.

In contrast, any upfront contribution by a transmission connection applicant toward deeper transmission augmentations (required at the time of connection or subsequently) depends on a negotiation between the parties, subject to the bounds set by Schedule 5.11.

Schedule 5.11(2) requires that the price for a negotiated transmission service should be at least equal to the avoided cost of providing it but no more than the cost of providing it on a stand-alone basis. This could be read as requiring TNSPs to price negotiated services to capture all current and future (including deep) augmentation costs, with future costs being one component of the avoided cost of providing the service. However, regardless of intent, it is not clear this approach is consistently applied by TNSPs, creating a risk of cross-subsidy by other consumers, particularly where the need for deep augmentation is accelerated.

Description of proposed rule change: The NER should provide TNSPs more explicit guidance on pricing connections, potentially through an AER published guideline similar to the distribution connection charge guideline or through amendments to Schedule 5.11 (noting Victoria's unique framework may require the AER to update its approach to the negotiated transmission service criteria). More explicit guidance will increase certainty and consistency of implementation, thereby helping to prevent socialisation of costs across the consumer base.

[10] See clause 11.98.8 and AER, *Proposed negotiated transmission service criteria*, November 2025. This approach is effectively a Victorian-specific derogation from the rules, whereby clause 5.2A does not apply due to Victoria's unique approach to planning the declared transmission system.

It is noted that it may be difficult to introduce similar upfront unit rates at the transmission level given the unique and bespoke nature of transmission augmentations, and that an exact replication of the distribution guidelines may not be possible. Consideration could be given to using a conservative $/MW or $/km estimate with an adjustment mechanism to account for overs and unders.

The rule should provide for the AER, in the proposed guideline, to consider how transmission network unit rates could be designed to account for changes in estimated and actual costs over time. Major transmission projects carry high costs and actual costs of projects have far exceeded initial estimates, particularly relative to early stage (class 5 or similar) estimates. Given this, it is important the unit rates are designed to account for these likely escalations.

If a prescriptive approach is unworkable, the principles could give more explicit guidance around ensuring pricing appropriately captures the full scale of augmentations needed to support a new load, avoiding cross-subsidy and ensuring existing consumers do not bear any current or future pricing risks from stranded assets. References to funded augmentations and prudential arrangements referred to in this paper may also be useful in these principles.

6.B Contribution to the NEO

Rule Change Request 2 will provide developers with improved and streamlined access to funded network augmentations and negotiated transmission connection outcomes, and avoid inequitable, distortionary outcomes regarding jurisdictional scheme cost recovery.

The NEO is:

> "to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:
>
> a) price, quality, safety, reliability and security of supply of electricity; and
>
> b) the reliability, safety and security of the national electricity system; and
>
> c) the achievement of targets set by a participating jurisdiction –
>
> i. for reducing Australia's greenhouse gas emissions; or

ii. that are likely to contribute to reducing Australia’s greenhouse gas emissions.”

This Rules Change Request improves the allocative efficiency of costs for new connections, supporting part a) of the NEO, by:

- Streamlining access to funded network augmentation pathways to improve the dynamic efficiency of network augmentation prioritisation by recognising (and capturing) the higher willingness-to-pay shown by proponents of large loads, such as data centres, and ensuring that costs are not socialised across the rate base [Gap 5,7].
- Aligning cost recovery of jurisdictional schemes between both distribution- and transmission-connected customers to remove a perverse incentive for proponents to seek transmission connections, thereby improving allocative efficiency between transmission and distribution networks and supporting the NEO [Gap 6].

6.C Expected benefits, costs, and impacts

Expected benefits

The rules changes proposed would provide broader system benefits by improving the incentives for large loads to connect at nodes with lower upstream congestion impacts.

These benefits include:

- Reduced system network augmentations costs from shift in development of new loads toward lower-impact locations, delivered by sharper locational incentives for connection at locations with less need for upstream augmentation and supported by improved access for other connecting loads [Gap 6, 7].
- Improved incentive to establish lower-cost distribution connections, where available, by addressing perverse incentive of jurisdictional charge exemption for transmission-connected loads [Gap 7].

- Improved dynamic efficiency of allocating finite capacity to proponents with higher willingness to pay through improvements to negotiated connection and funded augmentation pathways [Gap 5, 7]

Expected costs

Costs for these proposed rules changes relate to the increased complexity of connection planning for developers of large loads, who will be required to develop greater understanding of the upstream consequences of connection at a given node. Developing new frameworks for funded augmentations and standardised connection policies [Gap 5, 7] may also entail some costs.

Expected impacts

Where upstream augmentations cannot be avoided, connection proponents will benefit from increased agency in managing these impacts through improved pathways for funded network augmentations [Gap 5] and improved alignment of negotiating transmission connection processes.

Existing distribution-connected energy users will also benefit from cost reductions by sharing the burden of jurisdictional schemes equitably across transmission-connected users rather than recovering all jurisdictional costs within distribution charges [Gap 6].

All transmission-connected customers would face somewhat increased costs from jurisdictional schemes, if scheme cost recovery were extended to transmission-connected loads [Gap 6]. However, this may be considered an important element of obtaining and maintaining social licence.