Final Decision

AEMO Transmission Determination 2022 to 2027

April 2022

AUSTRALIAN
ENERGY
REGULATOR

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AER reference: AER212713

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1 Overview

We, the Australian Energy Regulator (AER), work to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. Our work is guided by the National Electricity Objective (NEO) which promotes efficient investment in, and operation and use of, electricity services in the long term interests of consumers.[1]

We must make a transmission determination for the Australian Energy Market Operator (AEMO) consisting of a pricing methodology and a negotiated transmission service criteria (NTSC).[2] We do not make a revenue determination for AEMO. Rather, AEMO is required to develop and publish its own revenue methodology for the services it provides in Victoria, which is available on its website: aemo.com.au.

1.1 Pricing methodology

Our final decision accepts AEMO's revised pricing methodology as it is consistent with the requirements set out in our draft decision and is compliant with the NER.

AEMO's revised pricing methodology incorporated our draft decision requirements:

- removed its policy to exempt energy storage from prices for prescribed transmission services.
- amended the basis for calculating a customer's locational charges to multiplying the locational price by the lower of the contract agreed maximum demand and the customer's actual average demand.
- stated it will undertake its best endeavours to publish its transmission prices by 15 March.

The role of a pricing methodology is to answer the question 'who should pay how much'[3] in order for a transmission business to recover its costs of providing prescribed transmission services. An approved pricing methodology does not relate to negotiated transmission services or other transmission services not subject to economic regulation under chapter 6A of the NER.

Section 3 contains our detailed consideration of the revised pricing methodology.

AEMO's Undertaking for setting 2022–23 prices

On 29 March 2022, we approved AEMO's proposed Undertaking under section 59A of the NEL to calculate prices for shared transmission services in accordance with

1 NEL, s. 7.

2 Schedule 6A.4.2(f) of the National Electricity Rules (NER) sets out the application of chapter 6A of the NER to AEMO.

3 AEMC, *Rule determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, 21 December 2006, p. 1.

the terms of its revised pricing methodology, for the period commencing 1 July 2022 and ending on 30 June 2023.

We discuss our reasons for accepting AEMO's proposed Undertaking in section 3.2.

Explanatory Statement on transmission charges for energy storage systems

In addition to our final decision, we have published an Explanatory Statement on the approach to transmission charges for energy storage.

This statement is designed to provide greater clarity of transmission charging arrangements in response to stakeholder feedback during our consultation on AEMO's pricing methodology.

We discuss the Explanatory Statement in more detail in section 3.5.1.1.

1.2 Negotiated transmission service criteria

Our final decision on the negotiating framework and NTSC is the same as our draft decision. We did not receive submissions on these aspects for our final decision.

A negotiating framework sets out procedures for negotiating the terms and conditions of access to a negotiated transmission service. The NTSC set out criteria that a TNSP must apply in negotiating those terms and conditions, including the prices and access charges for negotiated transmission services. They also contain the criteria that a commercial arbitrator must apply to resolve disputes about such terms and conditions and/or access charges.

Section 4 contains the NTSC, including our detailed consideration.

2 Background

2.1 Victorian electricity transmission arrangements

Victorian households and businesses consume electricity, which is supplied through a network of 'poles and wires'. The electricity network in Victoria is commonly divided into two parts:

- a transmission network, which carries electricity from the large generators to the major load centres
- distribution networks, which carry electricity from points of connection with the transmission network to virtually every building, house and apartment in Victoria.

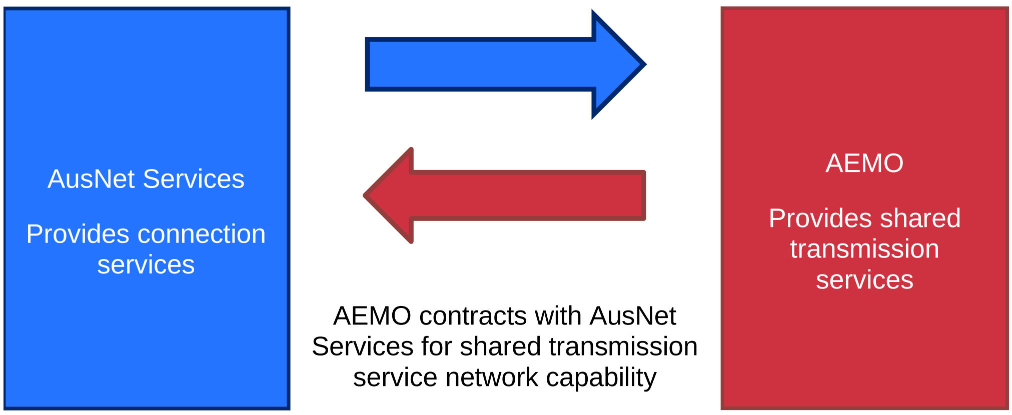
The Victorian transmission arrangements are different to other regions in the National Electricity Market (NEM).

As part of its functions, AEMO is responsible for providing shared transmission services. These consist of prescribed transmission use of system (TUOS) services and prescribed common transmission services. Hence, AEMO is a transmission network service provider (TNSP) under the NER.[4]

AEMO does not actually own assets that provide transmission services. Rather, it procures network capability under long-term contracts. Additionally, AEMO does not provide connection services to customers. AusNet Services owns and operates Victoria's shared electricity transmission network and provides connection services. AusNet Services is also the main source from which AEMO procures shared transmission services under contract. Figure 2.1 provides a basic overview of the Victorian transmission arrangements.

AEMO also has a substantial planning role under the Victorian transmission arrangements. It forecasts demand for prescribed transmission services, identifies network constraints, and commissions network augmentations.

Figure 2.1 Overview of the Victorian transmission arrangements



[4] NER, s. 6A.4.1.

In addition to AusNet Services and AEMO, Murraylink provides transmission services in Victoria. Where there are multiple TNSPs in a region, those providers must appoint a coordinating network service provider responsible for allocating all the AER-determined regulated revenue in that region.[5] Both AusNet Services and Murraylink appointed AEMO as the co-ordinating network service provider for Victoria.

Under this arrangement, AusNet Services and Murraylink provide AEMO information regarding their regulated revenues. AEMO then uses this information, among others, to derive prices for prescribed TUOS services and prescribed common transmission services in the Victorian region.

2.1.1 Transmission services

Transmission services can be prescribed or negotiated. Figure 2.2 provides an overview of how AEMO charges for each service.

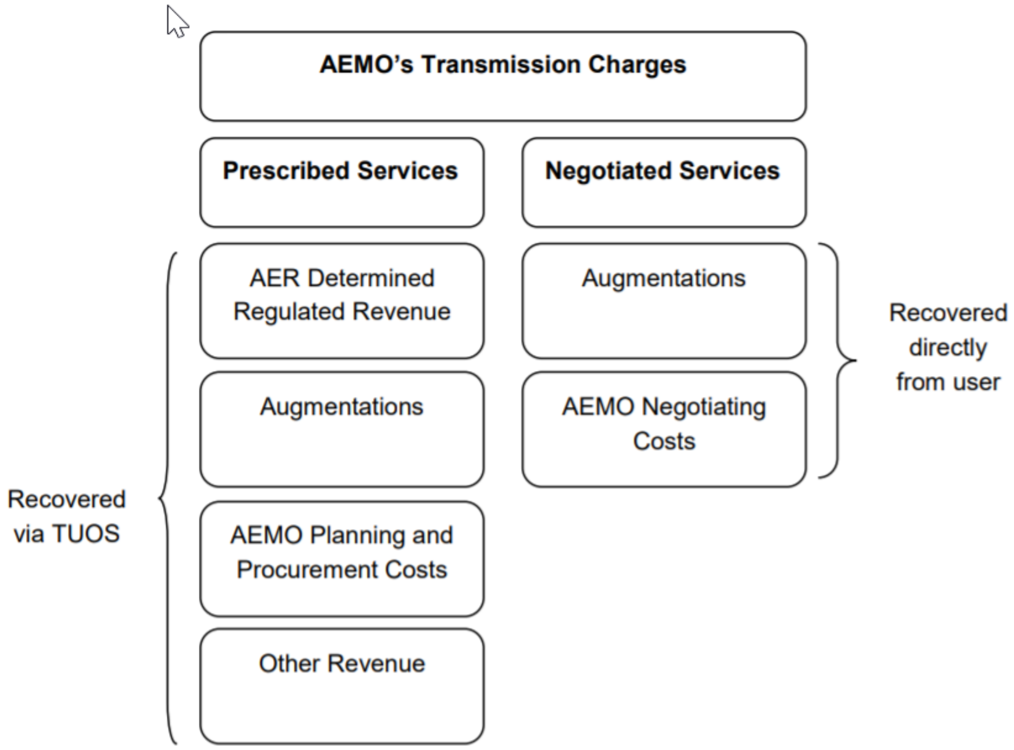
Most charges for prescribed transmission services are allocated to distribution network service providers (DNSPs) with some allocated to large customers directly connected to the transmission system.

Negotiated services, by contrast, are dedicated to an individual or small group of users. In these cases, any charges associated with those services are recovered from that user.[6]

5 NER, cl. 6A.29.1(a).

6 AEMO, *Revenue methodology for Victoria's electricity transmission system*, 1 July 2011, p. 5.

Figure 2.2 AEMO's Victorian transmission charging components



Source: AEMO, *Revenue methodology for Victoria's electricity transmission system*, 1 July 2011, p. 5.

2.1.2 How AEMO calculates its revenue requirement

AEMO's revenue comprises three main components: AER regulated revenue for Victoria, contestable augmentations, and AEMO's planning and procurement costs.

Under the Victorian transmission arrangements, AEMO collects the regulated revenues of AusNet Services and Murraylink. It then passes the revenues on to the TNSPs under long term contracts.

New augmentation costs form part of AEMO's revenue in certain circumstances. Under the Victorian planning arrangements, there is an opportunity for multiple parties to build, own and operate elements of the transmission system. This contestable process will occur if the capital cost of the augmentation is reasonably expected to exceed $10 million and it can be provided as a distinct and definable service.[7] Where this competitive tendering process is used to procure a new service, the cost of the augmentation is charged to AEMO under contract. The terms of these contracts are typically 30 years or in line with the technical life of the asset involved. The charges largely reflect the annual cost of the service being provided.

In the case of an augmentation being provided by an asset owner who is subject to our regulation (AusNet Services or Murraylink), the asset may be rolled into their

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7 AEMO, *Revenue methodology for Victoria's electricity transmission system*, 1 July 2011, p. 7.

regulated asset base (RAB) at the commencement of the next regulatory control period.[8] Alternatively it can continue to be charged under contract.

AEMO performs numerous energy market functions. The costs AEMO incurs in planning the Victorian transmission network and procuring network investment are passed onto transmission customers. Those costs form part of the revenue that AEMO recovers.

8 AEMO, *Revenue methodology for Victoria's electricity transmission system*, 1 July 2011, p. 7.

3 Pricing methodology

The role of a pricing methodology is to answer the question 'who should pay how much'[9] in order for a transmission business to recover its costs of providing prescribed transmission services. To do this, a pricing methodology must provide a 'formula, process or approach'[10] that when applied:

- allocates the aggregate annual revenue requirement (AARR) to the categories of prescribed transmission services that a TNSP provides[11]
- provides for the manner and sequence of adjustments to the annual service revenue requirement (ASRR)[12] and allocates that requirement to transmission network connection points[13]
- determines the structure of prices that a TNSP may charge for each category of prescribed transmission services.[14]

An approved pricing methodology does not relate to negotiated transmission services or other transmission services not subject to economic regulation under chapter 6A of the NER.

AEMO's pricing methodology addresses only the pricing matters for which it has responsibility. These are prescribed TUOS services and prescribed common services.

3.1 Final decision

Our final decision is to accept AEMO's revised pricing methodology for the 2022–27 regulatory control period (revised pricing methodology).

AEMO's revised pricing methodology incorporated our draft decision requirements:

- removed its policy to exempt energy storage from prices for prescribed transmission services. We discuss this in detail in section 3.5.1.1.
- amended the basis for calculating a customer's locational charges to multiplying the locational price by the <u>lower</u> of the contract agreed maximum demand and the customer's actual average demand.
- stated it will undertake its best endeavours to publish its transmission prices by 15 March.

We note AEMO has engaged further with customers on the impacts of changing its method for calculating locational prices, as we requested in our draft decision. We discuss in detail in section 3.5.1.3.

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9 AEMC, *Rule determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, 21 December 2006, p. 1.

10 NER, cl. 6A.24.1(b).

11 NER, cl. 6A.24.1(b)(1).

12 NER, cl. 6A.24.1(b)(2).

13 NER, cl. 6A.24.1(b)(3).

14 NER, cl. 6A.24.1(b)(4).

3.2 AEMO's Undertaking for setting 2022–23 prices

On 29 March 2022, we approved AEMO's proposed Undertaking under section 59A of the NEL to calculate prices for shared transmission services in accordance with the terms of its revised pricing methodology, for the period commencing 1 July 2022 and ending on 30 June 2023.[15]

We approved the Undertaking because it applies the framework we accepted in our draft decision and AEMO submitted in its revised proposal. It is also the framework we are accepting in this final decision. We consider AEMO's revised pricing methodology better reflects the pricing principles in the current environment than its pricing methodology for the 2014–19 regulatory control period (current pricing methodology).[16]

We had regard to stakeholder submissions on AEMO's revised pricing proposal in making our decision to accept AEMO's proposed Undertaking.

3.3 AEMO's revised proposal

As stated above, AEMO's revised pricing methodology incorporated all the requirements of our draft decision.

The revised pricing methodology includes the following changes to the current pricing methodology:

- Adoption of a new demand measure to derive locational prices. AEMO will use the 365-day method, which uses the maximum demand recorded on any day of the year. This replaces the MD10 method, which uses demand recorded during the 10 business days in which the system experienced peak demand.[17]
- Setting to zero all negative half-hourly energy and demand values at transmission connection points for deriving transmission prices.[18]
- Various changes to harmonise definitions and phrases as relevant with those in the NER, NEL and the AER Guidelines.
- Accounting for National Transmission Planner (NTP) function fees applicable as a Co-ordinating Network Service Provider under clause 2.11.3(ba) of the NER.[19]

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15 AEMO, *NER s95 Undertaking – July 2022 to June 2023*. See: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/aemo-determination-2022%E2%80%9327/update

16 For the 2019–20 to 2021–22 years, AEMO applied the pricing methodology we approved for the 2014–19 regulatory control period through an enforceable undertaking with the AER. See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/aemo-determination-2014-19/update.

17 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 14 December 2021, pp. 11–12.

18 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 14 December 2021, pp. 11–13.

19 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 14 December 2021, pp. 10 and 23.

- Accounting for the treatment of costs associated with Ministerial Orders pursuant to section 16Y of the National Electricity (Victoria) Act 2005 (NEVA).[20]
- Changes to energy/demand data used to calculate prices/charges resulting from a change in transmission pricing publication dates. This was due to the Victorian DNSPs' pricing proposal process changing from calendar to financial years.[21]

3.4 Assessment approach

We must approve a proposed pricing methodology if satisfied it:

- gives effect to, and complies with, the pricing principles for prescribed transmission services
- complies with information requirements of the pricing methodology guidelines.[22]

These requirements guided our assessment of AEMO's pricing methodology.

3.5 Reasons for final decision

The following sections set out the reasons for our final decision.

3.5.1 Assessment of the revised pricing methodology

3.5.1.1 Transmission charges for energy storage

We accept AEMO's decision to remove from its revised pricing methodology the policy to exempt energy storage from prices for prescribed transmission services (prescribed transmission prices).

Our draft decision did not accept AEMO's initial proposal to exempt energy storage from prescribed transmission prices because we considered it was not consistent with the requirements of the NEL and the NER.[23] In particular, we considered the proposal is not consistent with the pricing principles.

In addition, we noted AEMO's proposal was not consistent with the AEMC's draft rule determination on the "Integrating energy storage systems into the NEM" rule change (AEMC draft determination). The AEMC draft determination did not exempt energy storage from transmission and distribution prices. The AEMC considered an exemption would not promote the NEO as it would not reflect the efficient cost of providing services or the impact it may have on the network.[24]

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[20] AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 14 December 2021, p. 9 and 23.

[21] AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 14 December 2021, pp. 10–13 and 20–24.

[22] NER, cl. 6A.24.1(c); AER, *Electricity transmission service providers pricing methodology guidelines*, July 2014.

[23] AER, *Draft decision: AEMO transmission determination 2022 to 2027*, October 2021, pp. 12–14.

[24] AEMC, *Draft rule determination national electricity amendment (Integrating energy storage systems into the NEM) Rule 2021*, 15 July 2021, p. 103.

The AEMC's final determination upheld its draft determination to not exempt energy storage from transmission charges.[25] Therefore, any proposal to exempt energy storage from transmission prices is not consistent with the NER.

A number of stakeholders responded to our draft decision reasons for not accepting AEMO's proposed exemption for energy storage. Stakeholders stated that:

- charging TUOS to energy storage will increase whole-of-system costs to customers[26]
- neutrality between transmission and distribution connected energy storage should not be an objective[27]
- exemptions to energy storage would not have potential to lead to price shocks.[28]

Calls for greater clarity on transmission charges for energy storage

In addition to our final decision, we have published an Explanatory Statement on the approach to transmission charges for energy storage. This statement is designed to provide greater clarity of transmission charging arrangements in response to stakeholder feedback.

We observe that AusNet Services, Clean Energy Council (CEC), Neoen and Snowy Hydro Limited were not supportive of our draft decision, and the AEMC's final determination, to not allow AEMO to exempt energy storage from transmission charges.[29] These stakeholders considered charging energy storage creates uncertainty and compromises investment of energy storage in the NEM.

To reduce investment uncertainty, AusNet Services, CEC and Neoen requested the AER publicly reaffirm the AEMC's determination that new energy storage would be able to access the zero or low negotiated transmission charges currently paid.[30]

We consider the AEMC's final rule determination was clear on this point.

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25 AEMC, *Rule determination national electricity amendment (Integrating energy storage systems into the NEM) Rule 2021*, 2 December 2021 pp. 51–52, 55.

26 AusNet Services, *Letter Re: Australian Energy Market Operator (AEMO) determination 2022-27, Attachment – Access charges for negotiated storage*, 24 January 2022, p. 1.

27 AusNet Services, *Letter Re: Australian Energy Market Operator (AEMO) determination 2022-27, Attachment – Access charges for negotiated storage*, 24 January 2022, p. 2.

28 AusNet Services, *Letter Re: Australian Energy Market Operator (AEMO) determination 2022-27, Attachment – Access charges for negotiated storage*, 24 January 2022, p. 2, Snowy Hydro Limited, *AEMO transmission determination 2022 to 2027*, 24 January 2022, pp. 1–2.

29 AusNet Services, *Letter Re: Australian Energy Market Operator (AEMO) determination 2022-27*, 24 January 2022, p. 1; Clean Energy Council, *Email submission to the AER*, 13 January 2022, p. 1; Neoen, *Letter Re: Submission in response to the AER's draft determination AEMO transmission determination 2022 to 2027*, 24 January 2022, p. 1; Snowy Hydro Limited, *AEMO transmission determination 2022 to 2027*, 24 January 2022, p. 1.

30 AusNet Services, *Letter Re: Australian Energy Market Operator (AEMO) determination 2022-27*, *Attachment – Access charges for negotiated storage*, 24 January 2022, p. 1; Clean Energy Council, *Email submission to the AER*, 13 January 2022, p. 1; CEC, Request for AER clarification on NUOS charges, 16 December 2021; Neoen, *Letter Re: Submission in response to the AER's draft determination AEMO transmission determination 2022 to 2027*, 24 January 2022, p. 1.

The AEMC stated that the default is **not that** energy storage must pay transmission network charges, including TUOS (emphasis added).[31] Rather, energy storage participants can choose the service they need, which will in turn determine the price(s) they pay.

Further, the AEMC stated that new transmission-connected energy storage will be able to negotiate arrangements with TNSPs, including price and service levels, consistent with those negotiated for existing storage participants.[32] The AEMC noted it understands most energy storage proponents have negotiated very low or zero transmission charges with TNSPs. The AEMC further stated its final rule is not intended to alter those agreed charges.[33]

We have reiterated the AEMC's determination in our explanatory statement and that the AEMC's determination applies to transmission NEM-wide, and not just AEMO.

Calls to delay a decision on or reduce the timing of AEMO's pricing methodology

Our final decision approves the pricing methodology that AEMO will apply for the entirety of the 2022–27 regulatory control period.

We note Alcoa and Snowy Hydro Limited proposed that we reduce the time that the pricing methodology applies (a shorter regulatory period) or delay it altogether.

Alcoa suggested the AER only make a decision on AEMO's pricing methodology to June 2025 and revisit it once policy makers make further transmission pricing decisions as part of the post-2025 NEM design.[34]

Similarly, Snowy Hydro Limited considered the AER should delay its decision as the AEMC is likely to undertake further review of the transmission charging framework.[35] Snowy Hydro noted 'industry' would likely put in a rule change request seeking clarity on renegotiating arrangements of existing connection agreements when their current connection agreements expire.

We acknowledge these stakeholder views. However, we agree with AEMO that the benefits in delaying our decision or setting a shorter regulatory control period in this instance are not clear.[36]

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[31] AEMC, *Rule determination national electricity amendment (Integrating energy storage systems into the NEM) Rule 2021*, 2 December 2021 p. 52.

[32] AEMC, *Rule determination national electricity amendment (Integrating energy storage systems into the NEM) Rule 2021*, 2 December 2021 p. 53.

[33] AEMC, *Rule determination national electricity amendment (Integrating energy storage systems into the NEM) Rule 2021*, 2 December 2021 p. 53.

[34] Alcoa, *Submission on the AER's draft decision and AEMO's revised proposal for the revised transmission use of system pricing methodology 2022-2027*, 1 February 2022, p. 1.

[35] Snowy Hydro Limited, *AEMO transmission determination 2022 to 2027*, 24 January 2022, pp. 1–2, AEMC, *Rule determination national electricity amendment (Integrating energy storage systems into the NEM) Rule 2021*, 2 December 2021 pp. 53–54.

[36] AEMO, *Email response to follow up information request*, 7 March 2022 (AER reference: #13,734,853).

As a result, we make our final decision on AEMO's pricing methodology based on the NER and policy settings as they are at present, which will apply for the 5 year regulatory control period.

We are concerned that a delayed decision or shortened regulatory control period may not produce the intended result within the timeframe. For example, if we apply a 3 year regulatory control period there is risk that changes to the regulatory framework are not finalised in time for inclusion in AEMO's next pricing methodology proposal.

Further, a shortened period would introduce administrative burden for stakeholders. If changes to the regulatory framework are not final, then this additional review of the pricing methodology would impose unnecessary resource burden on AEMO, interested stakeholders and the AER. As noted by AEMO, these more frequent reviews in turn could increase uncertainty in prices.[37]

However, we expect that the decision makers will include guidance and transitional provisions regarding updates to current pricing methodologies, should the transmission pricing framework be amended. For example, as noted by AEMO, the Efficient Management of System Strength rule change includes provisions to enable specific amendments to affected TNSPs' pricing methodologies within a regulatory control period.[38]

3.5.1.2 Locational transmission charges

Demand measures for deriving locational prices

We maintain our draft decision to accept AEMO's change to use the 365 day method to measure demand for deriving locational prices as it is consistent with the NER requirements and our pricing methodology guidelines.

In making our draft decision, we considered whether the 365 day method better reflects the principle that locational prices:[39]

> …must be based on demand at times of greatest utilisation of the transmission network by Transmission Customers and for which network investment is most likely to be contemplated.

As detailed in our draft decision, we consider the 365 day method better reflects this principle than the MD10 method. This is because the period "of greatest utilisation of the transmission network" is no longer simply the maximum demand of the power system. In particular, renewable energy generation is now the main driver of investment.[40]

In the past, AEMO stated that planning for network investment could be undertaken on the basis of a supply mix with relatively predictable patterns of operation. Further,

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37 AEMO, *Email response to follow up information request*, 7 March 2022 (AER reference: #13,734,853).

38 AEMO, *Email response to follow up information request*, 7 March 2022 (AER reference: #13,734,853).

39 NER, cl. 6A.23.4(b)(1).

40 AER, *Draft decision: AEMO transmission determination 2022 to 2027*, October 2021, p. 15.

transmission network utilisation across maximum demand periods would be relatively similar.

However, the generator mix is shifting to more variable, intermittent energy resources and a greater geographic diversity of supply. Hence, network investment planning requires an hour-by-hour assessment of supply-demand at each transmission connection point, with different network utilisation across the day depending on new generation patterns.[41]

Further, AusNet Services supported our draft decision noting that peak demand is no longer the main driver of transmission investment.[42]

Alcoa submitted the change to the 365 day method would result in its smelter being allocated more transmission costs. Consequently, it would incur higher locational charges. These increased charges would occur even though the smelter is not changing the way it operates or uses the system.[43]

Alcoa noted the smelter has a relatively flat load profile and operates every day of the year.[44] It is able to curtail demand at times of peak demand when needed, which under the MD10 method would result in lower transmission costs. However, under the 365 day method it can only reduce its transmission costs if it reduces output.

Prior to making our draft decision, AEMO presented to us customer impact analysis of the changes to the 365 day method.[45] It showed that some customers will incur increased charges, such as Alcoa, and others reduced charges.

While we acknowledge the initial impacts the change to the 365 day method will have on customers, including Alcoa, we remain of the view that the 365 day method is likely to better reflect the pricing principles in the current environment.

We have not received further evidence since the draft decision that the MD10 method better reflects the requirements of the NER pricing principles than the 365 day method.

Further, Alcoa provides demand-response services that are important for maintaining the security and reliability of the Victorian transmission network. We consider the change to the 365 day method would not materially affect Alcoa's ability to provide such services in the medium term given current contractual and regulatory arrangements.

Allocating 50% of costs to locational charges

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41 AER, *Draft decision: AEMO transmission determination 2022 to 2027*, October 2021, p. 16.

42 AusNet Services, *Letter Re: Australian Energy Market Operator (AEMO) determination 2022-27*, 24 January 2022, p. 1.

43 Alcoa, *Submission on the AER's draft decision and AEMO's revised proposal for the revised transmission use of system pricing methodology 2022-2027*, 1 February 2022, p. 4.

44 Alcoa, *Submission on the AER's draft decision and AEMO's revised proposal for the revised transmission use of system pricing methodology 2022-2027*, 1 February 2022, p. 4.

45 AEMO, *Response to information request #001 – Price impacts of the transition to the 365 day method*, 10 August 2021 (CONFIDENTIAL).

We consider AEMO's allocation of 50 per cent of costs associated with prescribed TUOS services to the locational component is reasonable and consistent with the NER.[46]

In its submission, Alcoa proposed that demand is not a driver of transmission investment currently. Hence, the 50 per cent allocation to locational charges is not likely to be providing efficient signals via the locational charge.[47]

Alcoa suggested an alternative allocation may provide more efficient signals, such as based on incremental costs of accommodating additional demand at each connection point.[48] However, Alcoa noted there is currently insufficient publicly available information that would allow it to investigate this approach.

As a result, Alcoa requested the AER and AEMO to investigate further if an alternative approach would provide more efficient locational signals.

As Alcoa noted, the NER states that:

> (a) The annual service revenue requirement for prescribed TUOS services is to be allocated between a locational component (pre-adjusted locational component) and a non-locational component (pre-adjusted non-locational component) either:
>
> (1) as to 50% to each component; or
>
> (2) an alternative allocation to each component, that is based on a reasonable estimate of future network utilisation and the likely need for future transmission investment, and that has the objective of providing more efficient locational signals to Market Participants, Intending Participants and end users.

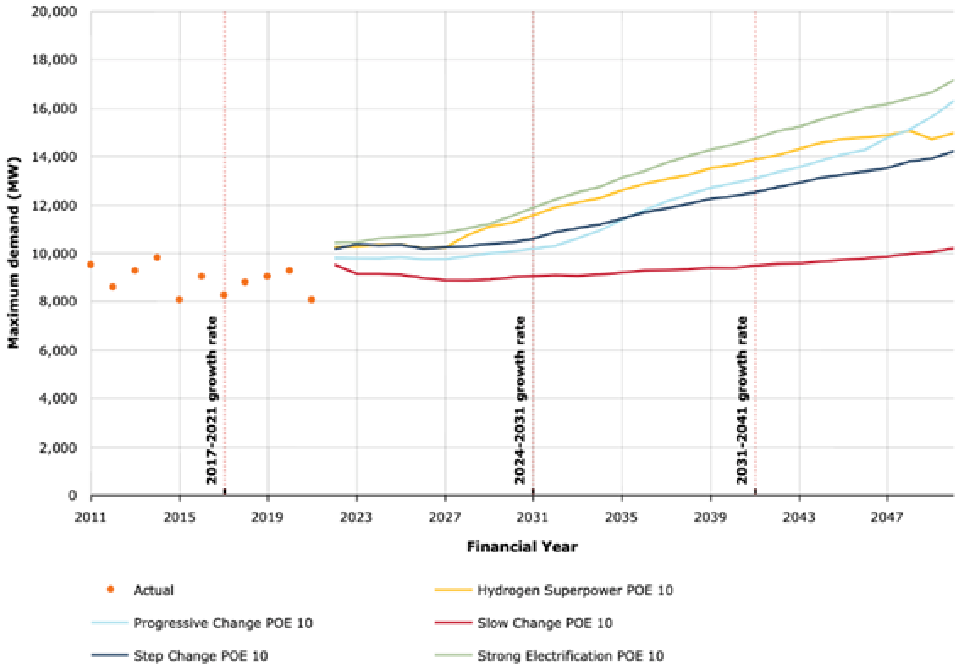
AEMO agreed with Alcoa that load growth is not the driver for network investment currently. Figure 2.1 shows AEMO forecasts low demand growth in the Victorian transmission network.

46 NER, cl. 6A.23.3

47 Alcoa, *Submission on the AER's draft decision and AEMO's revised proposal for the revised transmission use of system pricing methodology 2022-2027*, 1 February 2022, pp. 4–5.

48 Alcoa, *Submission on the AER's draft decision and AEMO's revised proposal for the revised transmission use of system pricing methodology 2022-2027*, 1 February 2022, pp. 4–5.

Figure 3.1 Electricity maximum demand



Source: AEMO, *Response to information request #005: Queries raised by Alcoa*, 3 March 2022.

We agree with AEMO that using an alternative allocation to the 50:50 ratio set out as the default in the NER is subjective. This contributes to the difficulty in setting an alternative allocation.

While load growth is a less significant factor in driving investment, increased renewable penetration is the new driver of investment (as discussed earlier).Based on the demand forecasts in Figure 2.1, for example, it is difficult to determine a more appropriate allocation between locational and non-locational charges.

The NER provisions for setting locational prices were developed with the goal of approximating long run marginal cost (LRMC)[49] signals.[50] Discussions during the development of these provisions acknowledged the difficulties with estimating LRMC signals. These discussions also demonstrated the tension between accuracy and ease of administration in developing methods to set locational charges.

For example, Major Energy Users submitted that 100 per cent should be allocated to locational charges because a 50 per cent allocation is not cost reflective.[51] A

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49 The NER provides a definition of LRMC with regard to distribution network services: "the cost of an incremental change in demand for [distribution network services] provided by a Distribution Network Service Provider over a period of time in which all factors of production…can be varied."

50 See AEMC, *Review of the electricity transmission revenue and pricing rules: Consultation program: Transmission pricing issues paper*, November 2005, p. 50; AEMC, *Draft rule determination: Draft national electricity amendment (Pricing of prescribed transmission services) rule 2006*, 19 October 2006, p. 39; AEMC, *Rule determination: National electricity amendment (Pricing of prescribed transmission services) Rule 2006 No, 22*, 21 December 2006, p. 42.

51 Major Energy Users, *Comments on the pricing requirements issues paper*, December 2005, p. 12 and 29.

consultant's analysis at the time indicated the allocation that would result in the best approximation of LRMC depends on the level of utilisation.[52] We note utilisation levels varies with location and time.

However, the same consultant's analysis indicated using a 50 per cent allocation to locational charges would provide a reasonable surrogate for LRMC on average.

Absent compelling evidence to the contrary, we consider the 50 per cent allocation to locational charges—set as the default allocation in the NER—is appropriate for AEMO's pricing methodology.

Volatility of locational prices

We consider AEMO's 'price capping' method to limit annual changes in prices for the locational component is reasonable and consistent with the NER.[53]

Alcoa noted AEMO's locational prices have been volatile over time. Alcoa pointed to the 2021–22 year in which Victorian locational price changes ranged between a 55 per cent increase and a 1.7 per cent reduction compared to the previous year.[54]

Alcoa noted the NER constrains year-on-year fluctuations in locational prices by no more than 2 per cent on a load weighted basis compared to the previous year.[55] Alcoa considered while AEMO's revised pricing methodology set out a worked example of this, it was still not clear how this approach was compliant with the NER.

The worked example in AEMO's revised pricing methodology suggests the annual change in locational prices for AEMO's connection points should all fall within a 4 per cent range (load weighted average change ± 2 per cent).[56]

On the other hand, we note the 2 per cent limitation on the annual changes to locational prices do not apply under two circumstances:

- to the extent the change in prices related to the adjusted modified load export charge (MLEC); or[57]
- the load at the connection point has materially altered.[58]

AEMO clarified that connection points with a lower than average percentage change in 2021–22 were those in which the MLEC component formed a lower proportion of the overall locational charge. Conversely, connection points with a higher than

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52 AEMC, *Review of the electricity transmission revenue and pricing rules: Consultation program: Transmission pricing issues paper*, November 2005, p. 50–51.

53 NER, cl. 6A.23.4(b)(2).

54 Alcoa, *Submission on the AER's draft decision and AEMO's revised proposal for the revised transmission use of system pricing methodology 2022-2027*, 1 February 2022, pp. 5–6.

55 Alcoa, *Submission on the AER's draft decision and AEMO's revised proposal for the revised transmission use of system pricing methodology 2022-2027*, 1 February 2022, pp. 5–6.

56 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 14 December 2021, pp. 21–22.

57 NER, cl. 6A.23.4(b)(3)(i).

58 NER, cl. 6A.23.4(b)(3)(ii).

average percentage change were those in which the MLEC component formed a greater proportion of the overall locational charge.[59]

Transmission pricing aspects outside the scope of this determination

We have not commented on the following transmission pricing aspects which were raised by Alcoa as they are outside the scope of this determination.

Alcoa noted:

- the recovery of common and non-locational charges through postage-stamped prices is inefficient. Alcoa considers a fixed charge would be more efficient.[60]
- the Victorian easement land tax contributes significantly to the increases in Alcoa's transmission charges.

We note that:

- postage stamp pricing of the common and non-locational charges is a requirement of the NER[61]
- the Victorian easement land tax is a jurisdictional obligation for Transmission networks.[62]

3.5.1.3 Consultation on the customer impacts of the 365 day method

We note that through discussions with AEMO and customer representatives that AEMO has consulted more widely with customers on the customer impact analysis of the change to the 365 day method, as was requested in our draft decision.[63] We consider AEMO's consultation has enabled customers, such as Alcoa, to make submissions on these impacts for consideration in our final decision.

As set out in our Better Resets Handbook, we note the importance and benefits of networks developing their proposals through genuine engagement with customers.[64]

> Networks that engage in genuine engagement with consumers are likely to result in better quality proposals being submitted to the AER. Proposals that reflect consumer preferences, and meet our expectations, are more likely to be largely or wholly accepted at the draft decision stage, creating a more effective and efficient regulatory process for all stakeholders. By encouraging network businesses to improve their consumer engagement, consumers will be central to the regulatory determination process. This will allow consumers to have a greater influence over the development of regulatory proposals by network businesses and, more importantly, ensure network businesses deliver outcomes valued by consumers.

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59 AEMO, *Response to information request #005: Queries raised by Alcoa*, 3 March 2022.

60 Alcoa, *Submission on the AER's draft decision and AEMO's revised proposal for the revised transmission use of system pricing methodology 2022-2027*, 1 February 2022, p. 6.

61 NER, cll. 6A.23.4(e) and (f).

62 *Land Tax Act 2005*, Section 24.

63 AER, *Draft decision: AEMO transmission determination 2022 to 2027*, October 2021, pp. 12–14.

64 AER, *Better resets handbook: Towards consumer centric network proposals*, December 2021, p .3.

> We consider this will also lead to many other benefits including; improved relationships and understanding between networks and consumers, greater faith from all parties in regulatory processes, and the generation of new ideas and regulatory approaches that benefit both consumers and networks.

We note that while AEMO consulted with stakeholder prior to submitting its pricing methodology, the engagement on the impacts of the 365 day method was not undertaken until after our draft decision. In light of our Better Resets Handbook, we consider AEMO's stakeholders would have benefited from engagement on a key issue such as the price impacts prior submitting its regulatory proposal.

We encourage and expect AEMO to continue to engage and work with its customers over the 2022–27 regulatory control period on transmission pricing impacts, and importantly, for the development of its next regulatory proposal.

3.5.2 Calculation and allocation of the aggregate annual revenue requirement (AARR)

In our draft decision we accepted AEMO's method for calculating and allocating the AARR as we consider it meets the NER requirements.

The AARR is the 'maximum allowed revenue' adjusted:[65]

- for a number of factors such as cost pass throughs, service target performance incentive scheme outcomes and contingent projects[66]
- by subtracting the operating and maintenance costs expected to be incurred in the provision of prescribed common transmission services
- by any allocation of the AARR within and between regions as agreed between TNSPs.[67]

Table 3.1 summarises our review of how AEMO's revised pricing methodology calculates and allocates the business' AARR.

Table 3.1 AEMO's proposed calculation and allocation of the AARR against the NER requirements

NER requirements	AER assessment
Requirement for the AARR to be calculated as defined in the NER—clause 6A.22.1.	Section 3.3 of AEMO's proposed pricing methodology satisfies this requirement.
Requirement for the AARR to be allocated to each category of prescribed transmission services in accordance with attributable cost share for each such category of service—clause 6A.23.2(a).	Section 3.3 of AEMO's proposed pricing methodology satisfies this requirement.
Requirement for every portion of the AARR to be allocated and for the same portion of AARR not to be	Section 3.3 of AEMO's proposed pricing methodology satisfies this requirement.

65 NER, cl. 6A.22.1.

66 NER, cl. 6A.3.2.

67 NER, cl. 6A.29.3.

allocated more than once—clause 6A.23.2(c).	
Subject to clause 11.6.11 of the NER, requirement for adjusting attributable cost share and priority ordering approach to asset costs that would otherwise be attributed to the provision of more than one category of prescribed transmission services—clause 6A.23.2(d).	Section 3.3 of AEMO's proposed pricing methodology satisfies this requirement.

3.5.3 Allocation of the annual service revenue requirement (ASRR) to transmission network connection points

We accept AEMO's revised pricing methodology for allocating the ASRR as we consider it meets the NER requirements. Table 3.2 summarises our assessment.

Table 3.2 AEMO's proposed allocation of the ASRR against the NER requirements

NER requirements	AER assessment
Requirement for the whole ASRR for prescribed entry services to be allocated to transmission network connection points in accordance with the attributable connection point cost share for prescribed entry services that are provided by the TNSP at that connection point—clause 6A.23.3(i).	Not applicable.
Requirement for the whole ASRR prescribed exit services to be allocated to transmission network connection points in accordance with the attributable connection point cost share for prescribed exit services that are provided by the TNSP at that connection point—clause 6A.23.3(j)	Not applicable.
Requirement for the ASRR for prescribed TUOS services to be allocated between pre-adjusted locational components and pre-adjusted non-locational components—clause 6A.23.3(a).	Section 3.3 and appendix B of AEMO's proposed pricing methodology satisfy this requirement.
Requirement for the recovery of the ASRR for prescribed common transmission services and the operating and maintenance costs incurred in the provision of those services to be recovered through prices charged to transmission customers and network service and network service provider transmission connection points set in accordance with price structure principles set out in clause 6A.23.4—clause 6A.23.3(h).	Sections 3.3 and 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement.

3.5.4 Development of price structure

We accept AEMO's revised pricing methodology and process for developing different prices for recovering the ASRR as we consider it meets the NER requirements. Table 3.3 summarises our assessment.

Table 3.3 AEMO's pricing structure against the NER requirements

NER requirements	AER assessment
Requirement for separate prices for each category of	Sections 3.4 and 3.5 and appendix B of AEMO's

prescribed transmission services—clause 6A.23.4(a)	proposed pricing methodology satisfy this requirement.
Requirement for fixed annual amount prices for prescribed entry services and prescribed exit services—clause 6A.23.4(g)	Not applicable.
Requirement for postage stamped prices for prescribed common transmission services—clause 6A.23.4(f)	Section 3.5.3 of AEMO's proposed pricing methodology satisfies this requirement.
Requirement for prices for locational component of prescribed TUOS services to be based on demand at times of greatest use of the transmission network and for which network investment is most likely to be contemplated—clause 6A.23.4(b)(1)	Sections 3.4 and 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement.
Requirement for prices for the locational component of ASRR for prescribed TUOS services not to change by more than 2 per cent per year compared with the load weighted average prices for this component for the relevant region—clause 6A.23.4(b)(2)	Section 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement.
Requirement for prices for the adjusted non-locational component of prescribed TUOS services to be on a postage stamp basis—clause 6A.23.4(e)	Section 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement.
Setting of TUOS locational prices between annual price publications–clause 6A.23.4(b)	Section 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement.

3.5.5 Information requirements

We are satisfied AEMO's revised pricing methodology complies with the pricing methodology guidelines' information requirements.

Key features of the proposal include:

- acknowledging AEMO is the coordinating network service in Victoria
- using the priority ordering approach under clause 6A.23.3(d) of the NER to implement priority ordering
- describing billing arrangements as in clause 6A.27 of the NER
- describing prudential requirements as in clause 6A.28 of the NER
- including hypothetical examples
- describing how AEMO intends to monitor and develop records of its compliance with its approved pricing methodology.

4 Negotiated services

Our transmission determinations generally impose control over revenues that a TNSP can recover from its provision of prescribed transmission services.[68] But we do not determine the terms and conditions of negotiated transmission services. Under the NER, negotiated services are provided under an agreement or as a result of a determination of a commercial arbitrator. These processes are facilitated by:

- a negotiating framework, and
- the NTSC.

A negotiating framework sets out procedures for negotiating the terms and conditions of access to a negotiated transmission service. The NTSC set out criteria that a TNSP must apply in negotiating those terms and conditions, including the prices and access charges for negotiated transmission services. They also contain the criteria that a commercial arbitrator must apply to resolve disputes about such terms and conditions and/or access charges.

These requirements apply only to Victoria due to its unique transmission arrangements. This is because Victoria is the only NEM jurisdiction in which AEMO is authorised to exercise declared network functions.[69] Where such arrangements apply, there is a separation of ownership of the declared transmission system from certain aspects of the operation and control of that system. The framework for connections to the transmission network in Victoria is therefore different to the rest of the NEM.

The NER previously required all TNSPs in the NEM to submit negotiating frameworks for AER approval as part of their revenue determination. In 2017, the AEMC removed this requirement from the NER for all NEM jurisdictions, except for Victoria (2017 rule change).[70] Rather, the AEMC elevated to the NER the principles that will underpin negotiations between connecting parties and incumbent TNSPs as part of the 2017 rule change.[71]

In Victoria, clause 11.98.8 preserves chapter 6A of version 109 of the NER, which contain the provisions regarding negotiating frameworks and the NTSC.[72]

4.1 Final decision

Our final decision is that the NTSC we published for consultation on 25 August 2021 will apply to AEMO in the 2022–27 regulatory control period, as those criteria give effect to the negotiated transmission service principles.[73]

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68 As we discussed in chapter 1, we do not make a revenue determination for AEMO.

69 For more information regarding AEMO's declared network functions, see National Electricity Law, s. 50C.

70 NER, clause 11.98.8.

71 AEMC, *Rule Determination: National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017*, 23 May 2017, pp. 198–203.

72 See also AEMC, *Rule Determination: National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017*, 23 May 2017, p. 75.

73 NER, clause 6A.9.1; 11.98.8.

As requested in our draft decision, AEMO has confirmed it will continue to apply the negotiating framework it developed with AusNet Services for the 2022–27 regulatory control period.[74]

In section 4.2, we discuss this negotiating framework that will apply to AEMO for the 2022–27 regulatory control period.

4.2 AEMO's negotiating framework

The 2017 rule change preserved the requirement for AEMO to have a negotiating framework in place. On the other hand, AEMO is not required to submit one to the AER for approval.[75] This is the reason AEMO did not submit a negotiating framework as part of its regulatory proposal on 19 April 2021. However, we are required, in our determination, to set out requirements in respect of the preparation, replacement, application or operation of the provider's negotiating framework.[76]

As set out in our draft decision, from discussions with AEMO and AusNet Services, we understand AEMO intends to continue with its negotiating framework from the 2014–19 regulatory control period (current negotiating framework).[77]

This negotiating framework is, in substance, identical to the negotiating framework AusNet Services included in the revised proposal to its 2022–27 transmission determination.[78] This would continue AEMO's and AusNet Services' practice of submitting a joint and co-branded negotiating framework.

We require that:

- AEMO's negotiating framework be the same as AusNet Services, due to the benefits that arise from this approach. When AEMO receives an application to connect to the Victorian Transmission Network, that service applicant must also negotiate with AusNet Services for connection services. For this reason, a common negotiating framework that both AEMO and AusNet Services apply during their negotiations with service applicants is appropriate.
- AEMO's negotiating framework continues to meet the minimum requirements set out in the NER as in force before the 2017 rule change.[79]

4.3 Negotiated transmission service criteria

Our final decision is that the NTSC we published on 25 August 2021 (reproduced in section 4.3.2) will apply to AEMO for the 2022–27 regulatory control period.

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74 AEMO, *Response to information request #006: Confirmation on AEMO negotiating framework*, 3 March 2022.

75 Sch. 6A.4.2(f)(1), (5) and (8) (as specifically amended in NER version 110).

76 NER (version 109), cl 11.98.8, sch. 6A.4.2(e) and cl 6A.9.3.

77 AER, *File note: Discussion on AEMO negotiating framework*, 12 August 2021.

78 AusNet Services, *Transmission revenue review 2023-2027: Revised revenue proposal: PUBLIC*, p. 166.

79 NER (version 109), cll. 11.98.8, sch. 6A.4.2(e) and cl 6A.9.5 .

4.3.1 Reasons for final decision

Our final decision is that the NTSC as reproduced in section 4.3.2 should apply to AEMO for the 2022–27 regulatory control period. This is because it adopts the negotiated transmission service principles as its criteria.[80]

We note that this NTSC is identical to the NTSC that have applied in Victoria (for AEMO and AusNet Services) since July 2014.

Our final decision is that the NTSC is the same as our draft decision. We received no further submissions on the NTSC for our final decision.

4.3.2 The NTSC

National Electricity Objective

1. The terms and conditions of access for a negotiated transmission service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the National Electricity Objective.

Criteria for terms and conditions of access

Terms and conditions of access

2. The terms and conditions of access for a negotiated transmission service must be fair, reasonable, and consistent with the safe and reliable operation of the power system in accordance with the NER.
3. The terms and conditions of access for negotiated transmission services, particularly any exclusions and limitations of liability and indemnities, must not be unreasonably onerous. Relevant considerations include the allocation of risk between the TNSP and the other party, the price for the negotiated transmission service and the cost to the TNSP of providing the negotiated service.
4. The terms and conditions of access for a negotiated transmission service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

Price of services

5. The price of a negotiated transmission service must reflect the cost that the TNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the Cost Allocation Methodology.
6. Subject to criteria 7 and 8, the price for a negotiated transmission service must be at least equal to the avoided cost of providing that service but no more than the cost of providing it on a stand-alone basis.

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80 NER (version 109), cll. 6A.9.1 and 6A.9.4(b).

7. If the negotiated transmission service is a shared transmission service that:

   (a) exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or

   (b) exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER

   then the difference between the price for that service and the price for the shared transmission service which meets network performance requirements must reflect the TNSP's incremental cost of providing that service (as appropriate).

8. For shared transmission services, the difference in price between a negotiated transmission service that does not meet or exceed network performance requirements and a service that meets those requirements should reflect the TNSP's avoided costs. Schedule 5.1a and 5.1 of the NER or any relevant electricity legislation must be considered in determining whether any network service performance requirements have not been met or exceeded.

9. The price for a negotiated transmission service must be the same for all Transmission Network Users. The exception is if there is a material difference in the costs of providing the negotiated transmission service to different Transmission Network Users or classes of Transmission Network Users.

10. The price for a negotiated transmission service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person. In such cases the adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.

11. The price for a negotiated transmission service must be such as to enable the TNSP to recover the efficient costs of complying with all regulatory obligations associated with the provision of the negotiated transmission service.

Criteria for access charges

Access charges

12. Any access charges must be based on the costs reasonably incurred by the TNSP in providing Transmission Network User access. This includes the compensation for foregone revenue referred to in clause 5.4A(h) to (j) of the NER and the costs that are likely to be incurred by a person referred to in clause 5.4A(h) to (j) of the NER (as appropriate).

Shortened forms

Shortened form	Extended form
AARR	Aggregate annual revenue requirement
ASRR	Annual service revenue requirement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DNSP	Distribution network service provider
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	Network service provider
TNSP	Transmission network service provider