16. Pricing Methodology

16.1 Introduction

This chapter presents information on Powerlink's Proposed Pricing Methodology for the 2023-27 regulatory period and proposed amendments to our current approved methodology.

Our Pricing Methodology describes how we allocate our annual prescribed revenue to the various categories of prescribed transmission services and transmission network connection points and determines the structure of our prescribed transmission charges.

A marked-up copy of our Proposed Pricing Methodology, which shows changes from our current Pricing Methodology, is provided in Appendix 16.01.

Key highlights

- We have undertaken a review of our transmission pricing arrangements. This involved a range of customer engagement activities since April 2018, to inform our Proposed Pricing Methodology.
- Our Transmission Pricing Consultation concluded in November 2020, after publication of a Final Positions Paper.
- We have proposed one key amendment to our existing Pricing Methodology as a result of our Transmission Pricing Consultation. This amendment will progressively transition customers to locational charges based on peak demand only. This transition will occur over the next two regulatory periods (or 10 years), commencing 1 July 2022.
- We also propose five other minor amendments to our existing Pricing Methodology to:
  - adjust the non-locational component of prescribed transmission use of system services (TUOS) by the advised National Transmission Planner (NTP) costs each year;
  - reference the National Electricity Rules (the Rules) regarding the calculation of payments between multiple Transmission Network Service Providers (TNSPs) in Queensland;
  - improve clarity in the application of excess demand charges;
  - clarify consistency with the AER's Pricing Methodology Guidelines regarding postage-stamped prices and prudent discounts; and
  - update the timeframe for publication of the Modified Load Export Charge (MLEC).

16.2 Regulatory requirements

The Rules[1] require us to submit a Proposed Pricing Methodology with our Revenue Proposal. The Rules also specify the requirements for a Pricing Methodology[2], which include consistency with the pricing principles for prescribed transmission services[3], the Australian Energy Regulator's (AER's) 2014 Transmission Pricing Methodology Guidelines[4] and any relevant regulatory information instrument.

16.3 Our Proposed Pricing Methodology

16.3.1 Review of pricing arrangements

We recognise affordability remains a key concern for our customers, both our large-scale directly-connected customers and end-users. We consider it vital that all parts of the electricity system, including transmission, play their role in trying to address affordability concerns and put downward pressure on prices.

We know our customers are changing the way they use the transmission network, as transformational changes take place throughout the electricity system (refer Chapter 2 Business and Operating Environment). Our challenge is to find ways to adapt to the changing environment and deliver our transmission services to meet customer expectations at the lowest long-run cost.

In early 2018, we commenced a review into our transmission pricing arrangements[5]. This review was prompted by customer input and changing expectations. We put forward a number of potential alternative pricing options which could be included as part of changes to our Proposed Pricing Methodology for the 2023-27 regulatory period or addressed more broadly through the Rules framework.

1 National Electricity Rules, clause 6A.10.1.
2 National Electricity Rules, clause 6A.24.
3 National Electricity Rules, clause 6A.23.
4 Pricing Methodology Guidelines, Australian Energy Regulator, 2014.
5 Transmission Pricing Consultation Process, Powerlink, https://www.powerlink.com.au/transmission-pricing-consultation-process.

The review focused on how we can enhance the role of transmission pricing arrangements to:

- provide stronger signals to customers to encourage more efficient use of the network, which lowers future network costs; and
- enable customers to reduce their costs by changes to their network usage.

Further detail on the proposed changes to our Pricing Methodology, our approach to the review, and customer and stakeholder input that informed the proposed changes, is outlined in sections 16.3.2 and 16.3.3.

16.3.2 Customer and stakeholder engagement

We engaged with a broad range of stakeholders as part of our Transmission Pricing Consultation. This included our Customer Panel, Energy Queensland (Energex and Ergon Energy) and customers connected directly to its distribution networks, other TNSPs and other directly-connected customers.

In addition to informal discussions with customers, key engagement milestones included:

- Customer Panel – held 19 April 2018;
- Transmission Pricing Webinar – held 11 May 2019;
- Transmission Pricing Consultation Paper (Appendix 16.02) – published 26 July 2019;
- Draft Positions Paper (Appendix 16.03) – published 26 August 2020; and
- Final Positions Paper (Appendix 16.04) – published 18 November 2020.

A description of these engagement activities are summarised in Table 16.1. We established a dedicated page on our website to provide information on our transmission pricing consultation, copies of our papers and a contact point for any feedback[6].

After the release of our Transmission Pricing Consultation and Draft Positons Papers, we offered our directly-connected customers the opportunity for one-on-one discussions. In total, we held 17 individual discussions of around one to two hours each with the majority of our directly-connected customers. The format of these discussions enabled customer-specific information about the impact of potential alternative pricing arrangements to be discussed openly and in more detail. It gave customers a further opportunity to clarify their understanding of what was being proposed and what this could mean for their individual business circumstances. Our customers acknowledged the enhanced transparency of this format and many welcomed and appreciated the time we took to enable tailored discussions to occur.

Further to the consultation specific engagement above, in the normal course of business, we engage regularly with the 20 or so directly-connected load customers for whom transmission pricing and billing is a key issue. Our customers, including generators, proactively bring any concerns to us for consideration either within or outside a formal consultation process. This input was one of the drivers for us to undertake a review of our transmission pricing arrangements.

We also updated our Transmission Pricing Overview document and released an introductory video on transmission pricing[7] on a webpage dedicated to helping our customers better understand transmission pricing arrangements. These were commitments we made to customers in The Energy Charter.

[6] Transmission Pricing Consultation Process, Powerlink, https://www.powerlink.com.au/transmission-pricing-consultation-process.
[7] Understanding Transmission Pricing, Powerlink, https://www.powerlink.com.au/understanding-transmission-pricing.

Table 16.1: Summary of engagement activities

Activity	Description
Customer Panel discussion	In April 2018, our Customer Panel provided input into a review of potential alternative pricing arrangements. We acknowledged that engagement was very early in the process. We discussed and sought initial feedback on the scope and purpose of the review, workshopped potential pricing objectives and introduced potential options to guide the forthcoming Transmission Pricing Consultation Paper.
Transmission Pricing Consultation Paper	We published a Consultation Paper in July 2019. To allow for a broad range of views, this Consultation Paper identified 10 possible alternative pricing options that centred around four key pricing areas, namely: • alternatives to Cost Reflective Network Pricing (CRNP); • improving how transmission customers are charged; • peak and off-peak charging; and • other initiatives. We sought early input into this paper via our Customer Panel, an open webinar with approximately 14 customer representatives, and through discussions with other TNSPs via Energy Networks Australia (ENA). We also held discussions with Energy Queensland to understand ways to better align the structure of transmission charges and distribution tariffs. We incorporated this feedback in the Consultation Paper. We received limited feedback on the Consultation Paper. Many customers advised that they would prefer further detail on their individual pricing impacts before they could comment. Most customers advised that they were open to further discussion on potential changes to the transmission pricing arrangements. Generally, our customers acknowledged the principles behind advancing cost-reflectivity. A summary of feedback received from stakeholders is included in Table 16.3.
Draft Positions Paper	In August 2020 we published our Draft Positions Paper. This built on the pricing criteria and potential options discussed in the Consultation Paper. It also discussed the feedback received on our Consultation Paper and the actions we undertook in response. This feedback also informed the refinement of the potential alternative pricing arrangements to four options for more detailed consideration, outlined in Table 16.2. These options were evaluated against three pricing criteria proposed in our Consultation Paper: • equity and fairness; • price stability and transparency; and • efficient price signals. We modelled in more detail individual customer impacts of the alternative pricing options, which enabled more tailored follow-up discussions with customers and stakeholders. Given the confidential nature of individual customer information, the Draft Positions Paper provided a high level overview of these outcomes. This included, for each option, an indication of the following impacts in both dollar and percentage terms for customers: • highest and lowest; • average Distribution Network Service Providers (DNSPs); and • what 80% of directly-connected customers would observe. A summary of feedback received from stakeholders is included in Table 16.3.
Final Positions Paper	In November 2020 we published our Final Positions Paper. The purpose of this paper was to advise customers and stakeholders of the outcome of our Transmission Pricing Consultation. The paper: • summarised discussions and feedback received; • described how engagement influenced our final positions; and • identified what changes we intend to make going forward and how they will be progressed. Based on the options canvassed during the consultation, our Final Positions Paper proposed one key amendment to our existing Pricing Methodology to progressively transition customers to locational charges based on peak demand only. This transition will occur over two regulatory periods (or 10 years), commencing 1 July 2022. Further information on the evaluation of customer feedback and how this informed the proposed amendment is discussed in Section 16.3.3. As a result of our engagement with customers, we also concluded that there would be benefit in undertaking further discussions with customers on MVA charging and to explore potential options to relax the annual side constraint on movements in locational prices in the future. These discussions will occur in the normal course of business.

16.3.3 Key changes to our Pricing Methodology

Options considered

The four options considered in our Draft Positions Paper are summarised in Table 16.2.

Table 16.2: Pricing options presented in the Draft Positions Paper

Option	Description	Permitted under the current Rules?
1. Rebalancing the locational and non-locational split to 60/40	Currently the Rules(1) require an allocation between locational and non-locational charges based on either: • a 50% split between each component (our current approach); or • an alternative that reflects future network utilisation and the likely need for future transmission investment. This option implements an alternative that would increase the weight applied to locational charges to 60%. This would strengthen the link between peak demand and utilisation. This is a first step to further enhance the cost reflectivity of transmission charges.	Yes.
2. Locational charges based on peak demand only	Currently the structure of our locational charges are based on a 50/50 split between peak demand and average demand. However, locational revenue requirements are calculated during periods of peak usage of the shared network. This option would remove the average demand component from our charging structure. This will mean that our locational charges and revenue requirements would be determined on a consistent basis.	Yes.
3. MVA charging	MVA is a measure of electricity that accounts for how loads use the transmission network. It is a 'complete' measure of power flow as it captures reactive power. Given reactive power is not as easily transported over long distances, loads that draw more reactive power will also require more network investment. MVA charging would improve the cost reflectivity of transmission charges as charges would vary depending on each load's reactive power efficiency. This means that less efficient loads would face a higher charge, which signals the additional investment required to service them.	No. This would require a Rule change.
4. Accounting for the side constraint	The side constraint operates to protect customers from price shocks. It limits the rate of change of locational charges between years to between 2% of the load-weighted average for Queensland. The trade-off is that it may dilute locational price signals to customers. A more dynamic side constraint could increase the efficiency of locational charges as it would allow more direct price signals.	No. This would require a Rule change.

(1) National Electricity Rules, clause 6A.23.3(a)(2).

Customer input and response

We received customer input on our Transmission Pricing Consultation Paper and our Draft Positions Paper. We also sought feedback from customers on whether they considered that any other changes were required to our Pricing Methodology or other pricing arrangements beyond those proposed in our consultation papers. This feedback and our response is summarised in Table 16.3.

Following discussions with our customers as outlined in Section 16.3.2 we received 10 submissions in response to our Draft Positions Paper. Five of these were formal submissions and five other stakeholders provided input by email. Appendix 16.05 Submissions to Powerlink's Transmission Pricing Consultation Paper provides a copy of these submissions[8].

[8] Note that six submissions are public, two are confidential to the Australian Energy Regulator (AER) only and two are confidential to Powerlink only.

Table 16.3: Summary of general customer input and response

Input received	Powerlink response
Transmission Pricing Consultation Paper	
General agreement with the pricing criteria, acknowledging its 'give and take' nature.	Proposed pricing criteria will be used to understand the interaction with alternative pricing arrangements.
Need more details about individual customer impacts prior to providing formal responses.	Conducted modelling at an individual customer level on the four options to provide greater detail. Offered to engage with individual customers to discuss direct impacts.
Questioned the usefulness of enhancing demand based pricing signals in the current low growth environment.	The Draft Positions Paper provided further information on a range of options including alternatives to those which wholly impact demand signals.
Acknowledge the complex nature of transmission pricing but prefer that the next consultation papers be as brief as possible.	The Draft Positions Paper was concise with information and modelling presented at a high level. We offered to have detailed discussions with individual customers and stakeholders during the consultation period.
Valued the nature of individual discussions and information could be tailored to how individual customers use the network.	To balance the ongoing transparency of this consultation against the sensitive nature of individual customer impacts, we will engage with the wider audience and continue direct discussions with our directly-connected customers.
Acknowledge the principles behind increasing cost reflectivity noting that there are limitations to how far this can be progressed.	The majority of options included in the Draft Positions Paper advance cost reflectivity in a way which can be furthered in the future.
Draft Positions Paper	
Loads have the capability to achieve similar outcomes (increased efficiency through transmission pricing arrangements) from other avenues (changes in customer behaviour) without the need for fundamental pricing reform.	We intend to progress with further engagement on MVA charging through other work streams outside our revenue determination process.
A clear transitional path should be included with any change, mindful of customer impacts.	We have proposed a transitional pathway over two regulatory periods in relation to locational charges being based on peak demand only.
Impacts of any change on the wider customer base should be considered in the overall outcome.	Our final position to move to locational charges based on peak demand only will be gradual, which should limit impacts on the wider customer base.
Proposals considered are significant, given the timing of broader reviews currently occurring (for example, the Coordination of Generation and Transmission Investment (COGATI) Review and Energy Security Board's (ESB's) Post 2025 Review). Material changes now may lead to unexpected outcomes.	Our final positions do not propose fundamental changes to the existing pricing framework. We will engage with customers and stakeholders again and seek wider customer support before progressing broader pricing framework changes like relaxation of the locational price side constraint.
Overall, support no change to pricing arrangements. The current pricing methodology provides a reasonable basis for price allocations.	As above.
Powerlink should focus on reducing the overall cost burden for all customers.	Powerlink's Revenue Proposal recognises that affordability remains a key concern for customers. We have proposed a target of no real growth in our operating expenditure and a 3% reduction in our capital expenditure in the 2023-27 regulatory period, compared to the current period. These forecasts, combined with a reduction in our Regulatory Asset Base (RAB) and Rate of Return (RoR), are the drivers of our forecast 11% nominal reduction in the indicative transmission price in the first year of the 2023-27 regulatory period and on average, increases over the remainder of the regulatory period to be within inflation (refer Chapter 11 Maximum Allowed Revenue and Price Impact).
The application of the side constraint appears to operate in conflict with the objectives of cost reflective network pricing in the current market transition.	We recognise the impact that the side constraint has on efficient pricing particularly in periods where higher levels of change are expected. We plan to engage further with customers on what alternative options for relaxing the side constraint would look like and if these arrangements would lead to better outcomes for customers.

Final Positions

Of the four alternative pricing options considered in the Draft Positions Paper two are currently allowed under the Rules[9] and could potentially be implemented in our Proposed Pricing Methodology for the 2023-27 regulatory period. These options were rebalancing the locational and non-locational split to 60/40 and locational charges based on peak demand only.

We received valuable feedback on our Draft Positions Paper specific to the individual options posed. The Final Positions Paper[10] described how this feedback influenced our decision-making, which are summarised below.

Rebalancing the locational and non-locational split to 60/40

We have decided not to progress this change in our Proposed Pricing Methodology for the 2023-27 regulatory period.

Customers understood the link between enhanced efficiency of transmission prices and a higher weighting of locational charges. However, they also recognised that practical limitations exist and these need to be considered in adapting to a change in locational price signals. One of the key reasons for our pricing review was to enable customers to reduce their electricity costs by changing their utilisation of the network.

In making the decision not to progress with this option, we acknowledged customer feedback that highlighted their limited ability to react to a locational price signal, particularly where customers have already located (and sunk costs). Some considered that locational price signals were already appropriate. Combined with relatively flat demand growth forecast over the 2023-27 and subsequent regulatory periods, we considered there would be limited benefit in allocating a higher proportion of transmission charges to locational at this stage.

Locational charges based on peak demand only

We have decided to progress this change in our Proposed Pricing Methodology for the 2023-27 regulatory period. This will include a mechanism to phase in the change to locational prices being based on peak demand only. This transition will occur gradually over 10 years (or two regulatory periods), commencing 1 July 2022.

There are a number of benefits in this proposed change. In particular, the change would better align how customers are charged with locational price calculation principles in the Rules. That is, that they be based on demand at times of greatest utilisation of the transmission network for which network investment is most likely to be contemplated[11]. Peak rather than average demand is a key consideration in network investment. Phasing out the average demand component would also provide a stronger, simpler link between each customer's peak usage of the transmission network and what they are billed each month. It would also better align our pricing structures with those applied by other TNSPs.

Fundamentally the change does not alter the methodology for allocating locational revenues[12] that we currently apply. The side constraint limits the rate of change in the locational price between years[13]. All things being equal, once the locational price reflects the new charging arrangement, the same amount of locational revenue is recovered.

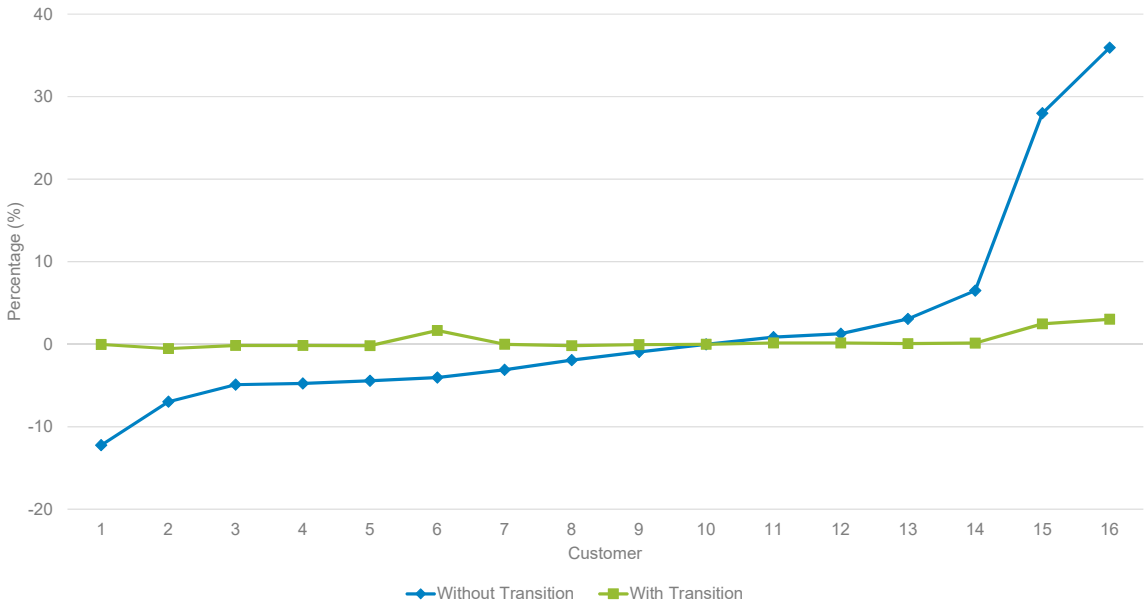
The AER's Pricing Methodology Guidelines allow transitional arrangements to be proposed where necessary[14]. We have proposed to implement this change over a 10 year transition period. We consider that a transitional arrangement to reduce the average demand component by 10% per year is reasonable to minimise unintended[15] price impacts and to allow time for customers to better understand and prepare for this change.

For illustrative purposes, Figure 16.1 shows the impact on directly-connected load customer charges as a result of removing the average demand component of locational prices, with and without the proposed transition mechanism. The impacts have been modelled on the basis of revenue, customer demand and energy input assumptions that underpinned our prescribed transmission prices for 2020/21. The 'with transition' line shows the customer impact (customers 1 to 16) in the first year of the 10 year transition period, which assumes 90% of average demand is considered. We expect the impact on customers in each of the remaining 9 year transition to be similar, noting that the 2% side constraint on movements in locational prices is assumed to remain in place. To the extent the side constraint remains an issue at the end of the transition period, the Rules provide customers with the opportunity to have their locational price recalculated[16].

9 Table 16.2 and National Electricity Rules, clauses 6A.23.3(a)(2) and 6A.23.4(b)(1).
10 Final Positions Paper Powerlink, Section 3.
11 National Electricity Rules, clause 6A.23.4(b)(1).
12 Using Cost Reflective Network Pricing (National Electricity Rules, clause S6A.3.2) and TPRICE (industry standard transmission pricing software).
13 National Electricity Rules, clause 6A.23.4(b)(2).
14 Pricing Methodology Guidelines, Australian Energy Regulator (AER), 2014, Section 2.1(j).
15 By application of the side constraint.
16 National Electricity Rules, clause 6A.23.4(b)(3)(ii).

This arrangement is expected to reduce the annual variation in revenues allocated[17] and collected. To be clear, the total amount we forecast to recover from each customer each year will not be materially impacted.

Figure 16.1: Indicative customer impact with and without transition



As a direct result of the change, we also expect there to be minimal price impact on residential and small business customers.

16.3.4 Other minor changes to our Pricing Methodology

We have put forward five other minor amendments to our Proposed Pricing Methodology (refer to Appendix 16.01) to reflect recent regulatory developments and to improve clarity. These include:

National Transmission Planner (NTP) Fee

Prior to commencement of the Integrated System Planning Rule[18], costs incurred by the Australian Energy Market Operator (AEMO) in relation to its NTP function were recovered from market customers. The Rule resulted in a reallocation of AEMO's NTP function fees to TNSPs from 1 January 2021.

We currently forecast a NTP cost allocation to Queensland of approximately $7.0m per annum (nominal 2020/21)[19]. The Rules require that the non-locational component of prescribed TUOS be adjusted for the amount of NTP function fees advised by AEMO[20]. For clarification, these fees do not form part of our Revenue Proposal.

This amendment is reflected in Section 6.8.3.2 of our Proposed Pricing Methodology.

Calculation of payments between multiple TNSPs

Powerlink is currently the sole provider of prescribed transmission services in Queensland. In the event that these services are provided by more than one TNSP in Queensland, financial transfers determined by the Co-ordinating Network Service Provider may be required. The process for the calculation of these transfers is outlined in the Rules[21].

This amendment is reflected in Section 7.2 of our Proposed Pricing Methodology.

17 Using Cost Reflective Network Pricing (National Electricity Rules, clause S6A.3.2) and TPRICE (industry standard transmission pricing software).
18 The National Electricity Amendment (Integrated System Planning) Rule 2020, (April 2020).
19 Forecast allocation based on NTP function fees forecast in AEMO's 2020-21 Budget and Fees.
20 National Electricity Rules, clause 6A.23.3(e)(6).
21 National Electricity Rules, clause 6A.27.5.

Excess Demand Charges

The AER's Pricing Methodology Guidelines[22] and our Pricing Methodology require that where a customer's actual maximum demand exceeds the contract agreed maximum demand, excess demand charges apply. In practice, revenue recovered through incremental charges from customers that have an exceedance event reflect the increase for the whole financial year.

This amendment is reflected in Section 6.11 of our Proposed Pricing Methodology.

Consistency with AER's Pricing Methodology Guidelines

We have identified two areas to clarify consistency with the AER's Pricing Methodology Guidelines in our Proposed Pricing Methodology. These changes clarify that:

- in deciding whether the energy or contract agreed maximum demand price is used to calculate the non-locational and common service components of prescribed TUOS services, the one that results in the lower estimated charge will apply[23]; and
- a very small number of prudent discounts will be in place over the 2023-27 regulatory period[24].

These amendments are reflected in Section 6.9.3 and Section 9 of our Proposed Pricing Methodology.

Timeframe for publication of the Modified Load Export Charge (MLEC)

Prior to the Distribution Network Pricing Arrangements Rule[25] we were required to publish the MLEC by 15 March each year. The Rule revised this timeframe to 15 February from January 2017 onwards. For clarity, we have amended the publication date to the February timeframe in the Rules[26].

This amendment is reflected in Appendix D of our Proposed Pricing Methodology.

16.4 Summary

Powerlink considers that its Proposed Pricing Methodology meets all compliance requirements given that it includes all relevant information prescribed under the Rules and AER's Pricing Methodology Guidelines 2014. Our Proposed Pricing Methodology for the 2023-27 regulatory period has been informed by our Transmission Pricing Consultation.

22 Pricing Methodology Guidelines, AER, 2014, clause 2.3(c)(7)(B).
23 Pricing Methodology Guidelines, AER, 2014, clause 2.3(c)(6).
24 Pricing Methodology Guidelines, AER, 2014, clause 2.1(k).
25 National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, (November 2020).
26 National Electricity Rules, clause 6A.24.2(b).