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By email: AERresets2027-32@aer.gov.au

Powerlink 2027-32 Transmission Revenue Proposal

13 May 2026

Dear Gavin,

Aurizon Network is pleased to make a submission to the Australian Energy Regulator's (**AER**) Issues Paper published on 30 March 2026 in respect of Powerlink's 2027-32 Transmission Revenue Proposal (**the Proposal**).

As Aurizon Network is a participating member of the Revenue Proposal Reset Group (**RPRG**) this submission addresses only those matters relevant to transmission prices for directly connected customers.

Aurizon Network has provided a summary of the outcomes it would like to see from the AER's assessment of the Proposal at the back of this submission.

About Aurizon Network

Aurizon Network operates the Central Queensland Coal Network (**CQCN**) which supports the export of metallurgical coal through east coast coal export terminals and the supply of thermal coal to domestic users and export terminals. The Goonyella and Blackwater coal rail systems include over 2000km of electrified track. In Financial Year (**FY**) 2025, approximately 74.5% of total coal volume transported over these two systems was metallurgical coal[1].

Aurizon Network provides regulated access to its electrified distribution network pursuant to an access undertaking approved under Part 5 of the *Queensland Competition Authority Act 1997 (Qld)*. However, it is unable to require users of the declared service (being the use of rail infrastructure for the purpose of transportation by rail) to operate electric locomotives where the regulatory framework prioritises above rail competition over environmental objectives and efficient use of rail infrastructure. Therefore, access seekers and access holders have the discretion to operate either an electric or diesel-powered locomotives. This means the

[1] Queensland Government (2025) Coal production data by mine, coal type and financial year, Open Data Portal. https://www.data.qld.gov.au/dataset/coal-industry-review-statistical-tables

provision of electric traction services is directly contestable and rail operators can bypass a regulated ‘monopoly’ service.

A key, but not the sole determinant of traction technology choice by rail operators is the relative cost of the supply of electricity. Furthermore, uncertainty about the future costs of the supply of electricity can also increase the risk to a rail operator of investment in, or refurbishment of, electric locomotives.

In FY2025, the provision of electric traction services in the CQCN consumed 546 Megawatt hours (**MWh**) representing approximately 1.15% of the total energy delivered on the Powerlink transmission network in that year. Across 18 directly connected sites in central Queensland, Aurizon Network contributed [redacted] of revenue earned by Powerlink from prescribed transmission services in FY2025 (excluding revenue from other sources). In aggregate, the total amounts paid to Powerlink for prescribed and negotiated transmission services in FY2025 equated to a unit cost of $[redacted] per MWh.

Indicative estimates of price impacts from the Proposal would increase this unit cost to $[redacted] per MWh in FY2032 excluding any impacts from traction substation reinvestments, contingent projects and the Gladstone project. This increase in Transmission Network Service Provider (**TNSP**) costs is unlikely to be offset by reductions in wholesale electricity prices and may further erode the competitiveness of electric traction services. These estimates also assume no change in current network flows and changes in lump sum attributions under locational pricing.

The reasonableness of current transmission prices and the transparency and predictability of how those prices will change over time is therefore an important consideration in a rail operator’s decision making regarding the investment in, and deployment of, electric locomotives. In addition, coal producers may seek commercial arrangements with rail operators which avoid the pass-through of regulated transmission and distribution network costs which potentially increases the commercial risks of operating electric train services.

Alignment with the National Electricity Objectives

Given the significant role that metallurgical coal will continue to play in steel production, maximising the use of the overhead power system promotes the public interest in reaching jurisdictional and national emission targets. While electrification of existing non-electrified railways may be a cost impediment to decarbonising rail transportation, the Goonyella and Blackwater systems in the CQCN are already electrified and represent the most effective means of supporting decarbonisation of rail transportation in central Queensland as more renewable energy supplies the national electricity market.

The current design of the safeguard mechanism along with potential price increases from the Proposal fails to promote the adoption of electric traction services. This is largely because smaller rail operators are not subject to the safeguard mechanism and may obtain cost advantages relative to incumbents by investing in diesel locomotives.

In addition, as electric consumption by a rail operator is not a scope 1 emission, a rail operator does not directly benefit from shifting utilisation from diesel to electric train services. In some circumstances, depending on the national contract portfolio of large national operators, a rail operator may be disadvantaged by switching a diesel locomotive for an electric locomotive under the current design of the safeguard mechanism.

Facilitating decarbonisation through maximising the use of the existing electrified rail network requires alignment of regulation with this objective. This expectation is also reflected in the national electricity objective in section 7 of the National Electricity Law which seeks 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:

……..

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.

Greater transparency of prescribed prices and relevant drivers.

Aurizon Network appreciates that the pricing methodology is an allocative approach that Powerlink is required to conform to and that the AER approves a revenue envelope for the TNSP to operate within. That is, the Capital Expenditure (**CAPEX**) and Operational Expenditure (**OPEX**) included within the revenue proposal may not be the CAPEX or OPEX that is incurred over the reset period.

Notwithstanding, the CAPEX and OPEX forecasts included in the Proposal are of sufficient detail and granularity to allow forecasts to be provided of expected revenue attributions to the relevant prescribed services. The Proposal provides no guidance as to how the proposed expenditure will influence, or be reflected within, different prescribed services. Rather, it only provides an overall average by dividing the allowable revenue by the forecast energy usage.

For large direct connected customers, such as Aurizon Network who pay prescribed transmission services, it is desirable to have greater transparency regarding:

- the impact of prescribed exit services from the capital expenditure forecasts;
- implications for locational pricing associated with expected changes in generation and load and the capital expenditure profile relating to those changes; and
- projections regarding the materiality of any true-up of system strength charges.

1. Prescribed Exit Services

A key feature of the pricing methodology is that the Annual Aggregate Revenue Requirement (**AARR**) is allocated to the relevant transmission service based on the Optimised Replacement Cost (**ORC**) values for assets used in providing the relevant service. This allocation then forms the Annual Service Revenue Requirement (**ASRR**) which is used to determine a lump sum amount for each connection based on the relative share of the ORC values for that connection as a proportion of the ORC value for all assets providing that service.

The inherent advantage in this approach is that prices for connection services are not expected to be subject to a material increases at the time of major asset renewal. However, this decoupling of the connection fee from the direct costs of providing the service, inhibits the ability of a connected customer to estimate its connection fees in response to changes in ORC values for assets providing exit services.

According to the FY2024-2025 Annual Information Order, Powerlink earned $82.1 million from prescribed exit services. It is unclear from the revenue proposal how this amount will vary from the substantial proposed replacement expenditure, including an estimated $232 million on

connecting infrastructure for 6 prescribed connections to the Blackwater and Goonyella coal rail systems[2].

Powerlink has provided Aurizon Network with indicative estimates of prescribed connection fees over the 2027-2032 revenue reset period on an all-else equal basis. The materiality of prospective increases in the revised ORC values for 6 of the prescribed connections requiring renewals are expected to result in a substantive increase in the prescribed exit services for those connections. This is unexpected under the pricing methodology which appears intended to avoid price shocks at the asset renewal completed by Powerlink.

Aurizon Network recommends the AER draft decision increase pricing transparency for directly connected customers by:

- including a high-level breakdown of proposed CAPEX over the 2027-2032 revenue reset period by prescribed transmission service;
- requiring the pricing methodology to be amended to include a new section on information disclosure which requires the annual notification of prescribed exit service fees to include:
    - the ORC values associated with that connection used in the determination of that fee; and
    - the total ORC value for assets providing prescribed all exit services in that year.

This information transparency will allow Aurizon Network to better communicate the variation in prescribed transmission costs to both our access holders and train operators, and evaluate the potential price impacts of these identified and all future renewals well before assets reach end of life.

2. Locational TUOS Prices

Aurizon Network's load profile is that of 'low load factors' where average demand (kW) is a low proportion of maximum demand (kW). This is consistent with large variable loads where an electrical track section is subject to a sufficiently large number of comparable half hour periods at peak demand (constrained by train separation and headways) and a substantial number of half hour periods below that maximum demand. Electrical sections with higher train density will also typically have higher load factors.

The impact of this load profile is two-fold:

- the maximum demand is relatively stable over time; and
- the demand charge component of locational TUOS charges is the majority of the locational TUOS charge (84% in FY2025).

[2] Powerlink (2026) Powerlink 2027-32 Revenue Proposal: Project Pack Traction Supply Infrastructure Replacement Programme, January. The CP.01922 – Grantleigh Substation Reinvestment project amount include costs that will be incurred over the 2027-32 and the 2032-37 reset periods.

The practical effect of this stable maximum demand profile[3] is that locational TUOS charges are expected to be the lump sum amount determined through the Cost Reflective Network Pricing model. The locational price will also subject to constraint on excessive price increases from a change in the use of transmission elements through the 2% side constraint.

Under the current pricing methodology and the Proposal, the lump sum amount is a function of the amount of transmission assets used to supply electricity from a generator(s) to the load at the connection point as a proportion of total flow over those same assets.

Therefore, the amount of costs allocated to a connection point is dependent on total network flows and influenced by:

1. any variation in maximum demand under peak operating conditions at that connection point;

2. variation in maximum demand from all connection points; and

3. changes in the generation mix and dispatch.

Only the first of these factors is in the control of the connected party. Aurizon Network is concerned with how its locational TUOS charges will evolve over the reset period in response to substantive changes in network flows and investments. This is particularly the case in respect of the $2.3 billion Gladstone project which is stated as being necessary to:

- address the retirement of the Gladstone Power Station; and

- support increased demands on the network as heavy industry moves toward electrification of their operations.

Given the relatively stable maximum demand at Aurizon Network's connections, neither of these circumstances are within Aurizon Network's control. Therefore, it would be reasonably expected that locational TUOS charges would be subject to the protection of the 2% side constraint. However, the side constraint may not operate in this way for two reasons:

- if there is no increase in aggregate maximum demand associated with increased industrial demand or electrification of operations, then all existing connection points may observe considerably higher lump sum allocations from the current allocation methodology with significant increases in the 'load weighted average TUOS locational price for the region'; and

- where the side constraint might be expected to limit locational price increases this is also distorted by the transitional pricing arrangements for locational TUOS prices.

Importantly, directly connected load customers have no visibility of what transmission elements are associated with their individual connections or how the transmission elements used would expect to change in response to substantive changes in the sources of generation given the TPRICE model is updated on an annual basis.

The current and proposed, pricing methodology is not clear on the level of granularity associated with what constitutes a 'transmission element' for the purpose of Appendix C of the

[3] Where maximum demand is the average of the top 10 half-hourly peak demands between November and March.

pricing methodology. Directly connected customers would also benefit from a requirement for the annual price notification to include:

- the load weighted average TUOS locational price for the region applicable to that connection point; and
- a summary of the generation assets used in the supply of electricity to that load point (as determined using the TPRICE model).

The latter will assist a directly connected customer understand how the changes in maximum peak load and generation influence its locational TOUS charges over time.

The Proposal retains the previously approved transition to reduce the component of the locational TUOS charges recovered from average demand such that the relevant percentage applicable to the average demand component by the end of the 2027-2032 reset period is 0%. How this transition affects the locational TUOS price ($/kW) for a connection point will be dependent on the connection points load factor.

Connection points with low load factors will see lower annual price increases (as the lump sum is mainly being recovered by the maximum demand) and high load factors will see higher annual price increases to recover that same lump sum. This is observed in the Table 1 which shows the expected annual price change, all else equal, for different load factors.

As the 2% side constraint is applied to the load weighted average TUOS locational price for the region, a connection point with a low load factor will be subject to a much higher effective side constraint which reflects the impact of the transitional arrangements where the weighted average locational price change reflects the weighted average load factor.

Table 1 Locational Price Change Under Transitional Arrangements by Load Factor[4].

		Load Factor						
Year	**Relevant %**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**	**0.8**
FY2023	**90%**	1.7%	2.4%	2.9%	3.4%	3.9%	4.3%	4.7%
FY2024	**80%**	1.7%	2.4%	3.0%	3.6%	4.1%	4.5%	4.9%
FY2025	**70%**	1.8%	2.5%	3.1%	3.7%	4.2%	4.7%	5.1%
FY2026	**60%**	1.8%	2.5%	3.2%	3.8%	4.4%	4.9%	5.4%
FY2027	**50%**	1.8%	2.6%	3.3%	4.0%	4.6%	5.2%	5.7%
FY2028	**40%**	1.9%	2.7%	3.4%	4.2%	4.8%	5.5%	6.1%
FY2029	**30%**	1.9%	2.8%	3.6%	4.3%	5.1%	5.8%	6.5%
FY2030	**20%**	1.9%	2.8%	3.7%	4.5%	5.4%	6.1%	6.9%
FY2031	**10%**	2.0%	2.9%	3.8%	4.8%	5.7%	6.5%	7.4%
FY2032	**0%**	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%

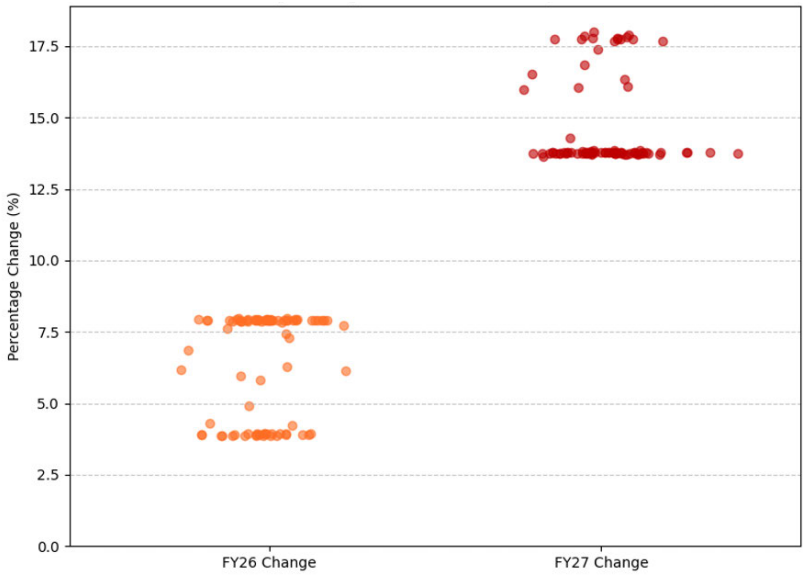
Source: Aurizon Network Analysis

Aurizon Network also notes that the application of the side constraint does not appear to be a limiting factor to the annual change in the locational price where all connection points increase by a similar amount. For example, the FY2027 locational price changes shown in Figure 1 fall within a narrow band of approximately 4%. Therefore, the side constraint has limited effect

[4] Scenarios assume the same fixed lump sum and maximum demand with only the load factor varying and influencing the average monthly demand.

where a ‘rising tide lifts all boats’, potentially rendering any protection intended by the side constraint negligible.

Figure 1. Annual Percentage Change in Locational Price for Queensland Nodes



Source: Aurizon Network analysis of Powerlink Schedule of Transmission Shared Network Prices

Aurizon Network requests the AER clarify the policy intent of the 2% side constraint and whether:

- it should be adjusted to account for the transitional arrangements;
- it should operate to prevent a material increase in the locational prices associated with material changes in the generation market or from material capital expenditure growth projects unrelated to any material increase in maximum demand from that connection point; and
- prudent discounts to the common and non-locational TUOS charges are appropriate to offset increases in locational TUOS charges above CPI + 2% for a connection point where:
    - there is no material increase in maximum demand; and
    - the electric demand is contestable with other energy sources (i.e. diesel locomotives) to better promote the National Electricity Objective.

3. System Strength Services

The Proposal includes variations to the pricing methodology to introduce system strength user charges. Appendix 10.01 of the proposal estimates an anticipated revenue requirement of $476 million associated with the provision of these services.

Aurizon Network recognises the AER’s *Final Decision on the Pricing methodology guidelines: System strength pricing* adopts an average cost approach for determining the relevant system strength charge on the basis it:

- results in stable pricing across system strength charging periods; and

- moves the costs of providing system strength transmission services to the parties that require those services. This in turn reduces the costs to be recovered from customers via prices for prescribed common transmission services.

The decision implies that the revenue collected from system strength pricing will not cover its costs and the shortfall will need to be recovered through prescribed common charges. However, the revenue proposal does not provide an indication of the expected materiality of this short fall and how much of the $476 million will need to be recovered from transmission users.

Aurizon Network also considers direct connected customers who fund their own STATCOM or SVC transmission assets through prescribed or negotiated exit services should be exempt from contributing towards system strength services. The benefits of these capabilities are acknowledged in the revenue proposal:

> *Phase balancing Static Var Compensators (SVCs), which include harmonic filtering, serve to maintain quality of supply to other network customers within prescribed standards.*

In addition, an SVC improves system power factor by supplying or absorbing reactive power (**MVAr**), reducing the reactive component of the load so that less MVA is required for the same Megawatt (**MW**) demand. However, as locational prices are based on MW rather than MVA, Aurizon Network locational TUOS charges are likely to exceed the demands our customer loads place on the transmission network where the Aurizon Network power factors are higher than other direct connections for the same MW. This was recognised by Powerlink in its consultation of the pricing methodology in the 2022-27 Transmission Revenue Proposal:

> *MVA is a measurement of electricity that accounts for how loads use the transmission network. MVA is a key determinant of network investment as it represents the full measurement of power flow through electricity assets. A shift towards MVA charging will enhance cost reflective pricing principles by factoring in reactive power efficiencies of loads*

Engagement with Powerlink at that time indicated that Aurizon Network would benefit from a move to MVA pricing but may require the locational pricing for other direct connect customers to be increased over time due to the side constraint.

The 2022-2027 pricing methodology did not implement MVA pricing as the 2% side constraint would not allow for the necessary redistributions between connection points. Consequently, the pricing methodology is a double edge sword for directly connected customers with SVC capabilities as they:

- pay locational TUOS charges which exceed the amount commensurate with cost reflective network pricing as MW does not reflect the driver of network investment; and

- will also be required to contribute to system strength services where they already fund infrastructure providing system strength externalities to other transmission users.

It is not readily apparent as to why generators should obtain the benefit of long-term stable prices but collectively, and in aggregate, not generate revenue to meet the full costs of those services, yet direct connected load customers are required to address their own impacts on voltage regulation and contribute to the provision of system strength services.

Aurizon Network considers that given the substantial capital expenditure included in the Proposal the AER should re-evaluate whether locational prices should be established based on MVA. The scale of the capital expenditure over the 2027-32 period was not expected or considered in consultation of the pricing methodology for the current 2022-2027 period on whether to adopt MVA pricing.

Summary of Recommended Positions

Aurizon Network is seeking the following outcomes from the AER's assessment of the Proposal:

- the inclusion in the Pricing Methodology of a new section on information disclosure which requires, where requested by a directly connected customer, to provide in an annual price notification:
    - the ORC value for the connection assets for a prescribed exit service;
    - the ORC value of all assets providing prescribed exit services;
    - the load weighted average TUOS locational price for the region;
    - the generations asset determined to be servicing the load at that connection point;
- are revisions are required to the 2% side constraint to:
    - adjust for the operation of the transmission mechanism to maximum demand; and
    - account for the increase in maximum demand on the Gladstone Project transmission assets (i.e. the locational price for a connection point should not be increasing where the project justification is increasing demand);
- should locational prices be calculated on MVA rather than MW basis;
- whether prudent discounts on the non-locational TUOS and common charges should be deemed prudent to cap the increase in locational charges to CPI + 2% where a connection:
    - has not materially increased its maximum demand; and
    - the connection is associated with supply and sale of electricity to services which can bypass the supply of that electricity;
- whether directly connected customers (generation or load) which fund SVCs or STATCOMs either privately, or through prescribed exit services, should be excluded from the system strength true up arrangements.

Conclusion

Aurizon Network will continue to engage with its access holders, train operators and Powerlink to assess the impact of the Proposal on the cost of supply and sale of electricity to electric traction services and the implications for demand for those services. Should the AER wish to discuss this submission please contact myself at [redacted].

Elements of this submission are commercial-in-confidence and a redacted version has been provided suitable for publication.

Kind regards,

[redacted]

Jon Windle
Manager – Network Regulation