DRAFT DECISION
Powerlink transmission determination
2017−18 to 2021−22

Overview

September 2016

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Invitation for submissions

Energy consumers and other interested parties are invited to make submissions on our draft decision for the Powerlink electricity transmission determination by **Thursday 1 December 2016.**

We will consider and respond to submissions in our final decisions in late April 2017.

We prefer that all submissions are in Microsoft Word or another text readable document format. Submissions on our draft decision should be sent to: Powerlink2016@aer.gov.au.

Alternatively, submissions can be sent to:

Mr Sebastian Roberts
General Manager
Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

(1) clearly identify the information that is the subject of the confidentiality claim

(2) provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website. For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy (October 2008), which is available on our website.

We will hold a pre-determination conference on 19 October from 10am. If you are interested in attending this forum, have any queries about this draft decision or about lodging submissions, please send an email to: Powerlink2016@aer.gov.au.

Note

This overview forms part of the AER's draft decision on Powerlink's transmission determination for 2017–22. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Maximum allowed revenue

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Pricing methodology

Attachment 13 – Pass through events

Attachment 14 – Negotiated services

Contents

Shortened forms

Shortened form	Extended form
AARR	aggregate annual revenue requirement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	annual service revenue requirement
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DMIA	demand management innovation allowance
DRP	debt risk premium
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
MAR	maximum allowed revenue
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
NTSC	negotiated transmission service criteria
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice

Shortened form	Extended form
RPP	revenue and pricing principles
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
TNSP	transmission network service provider
TUoS	transmission use of system
WACC	weighted average cost of capital

1 Introduction

We, the Australian Energy Regulator (AER), are responsible for the economic regulation of electricity transmission and distribution systems in all Australian states and territories, with the exception of Western Australia. Powerlink owns and operates Queensland's shared electricity transmission network. We regulate the revenues that Powerlink can recover from its customers.

Powerlink submitted a revenue proposal for its electricity transmission network on 28 January 2016. The proposal sets out the revenue that Powerlink proposes to recover from electricity consumers through transmission charges for the period 2017–22. This overview, together with its attachments, constitutes our draft decision on Powerlink's revenue proposal.

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework governing electricity networks. In regulating Powerlink, we are guided by the National Electricity Objective (NEO), as set out in the NEL. The NEO is:[1]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

1.1 Structure of overview

This overview provides a summary of our draft decision and its individual components. The remainder is structured as follows:

- Section 2 provides a high level summary of our draft decision
- Section 3 provides a breakdown of our draft decision into its key components
- Section 4 sets out our draft decision on the incentive schemes that will apply to Powerlink for the 2017–22 regulatory control period
- Section 5 explains how we apply the regulatory framework, in particular the NEO, the RPPs and the interrelationships between the constituent components
- Section 6 outlines our consultation process in reaching this draft decision and our view of Powerlink's consumer engagement undertaken in developing its revenue proposal
- Appendix A contains the full list of constituent components that make up Powerlink's proposal and our draft decision on each of them (constituent decisions)

[1] NEL, s. 7.

- Appendix B lists the stakeholder submissions received on Powerlink's revenue proposal.

In our attachments to this decision we set out detailed analysis of the constituent components that make up our draft decision.

1.2 Our process

This draft decision is one of the key steps in reaching our final decision. Our final decision will be released no later than 30 April 2017. Before that, Powerlink will have the opportunity to submit a revised proposal in response to this draft decision. Stakeholders will also have the opportunity to make submissions to us on our draft decision and Powerlink's revised proposal.

Following receipt of the revised proposal and submissions, we will then make our final decision taking into account the revised proposal, submissions and any other relevant information. Table 1.1 lists the key dates and consultation deadlines for the process.

Table 1.1 Key dates and consultation

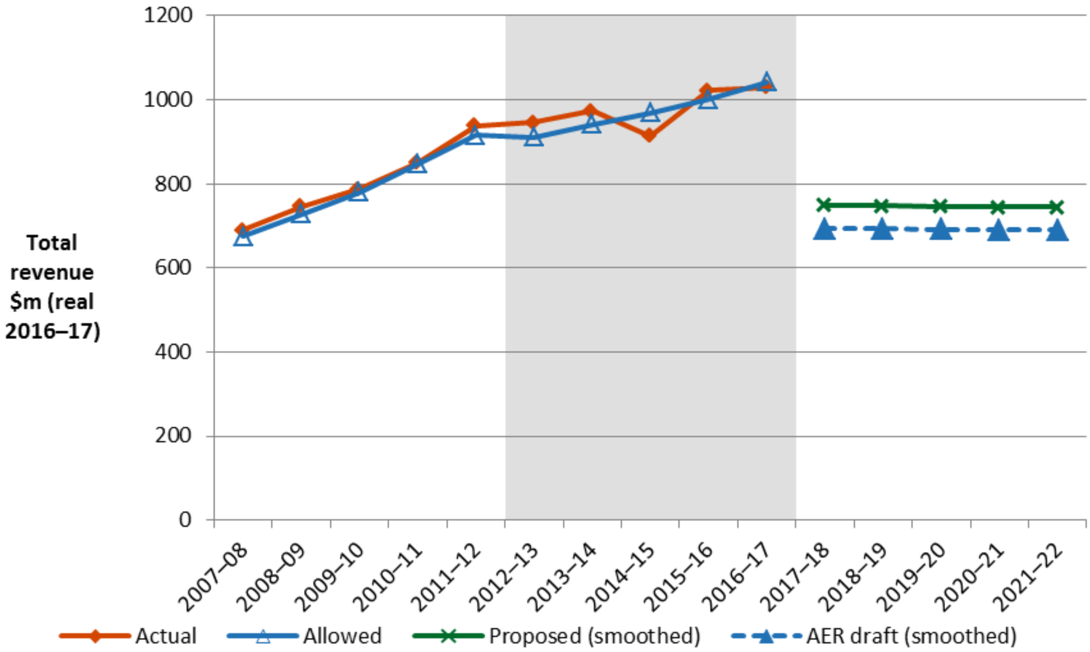
Task	Date
Revenue proposal submitted to the AER	28 January 2016
AER released Issues paper	March 2016
AER held public forum	15 March 2016
Submissions on revenue proposal closed	28 April 2016
AER draft decision published	29 September 2016
AER public forum to explain draft decision	19 October 2016
Submissions due on draft decision	1 December 2016
Revised revenue proposal due to AER	1 December 2016
Further submissions, including on revised proposals	23 December 2016
AER release of final decision	No later than 30 April 2017

2 Summary of draft decision

Our draft decision is that Powerlink can recover $3720.8 million ($ nominal, smoothed) from consumers over the 2017–22 regulatory control period. This is a 7.4 per cent reduction from Powerlink's proposed revenue allowance of $4017.2 million ($ nominal).

Figure 2.1 compares our draft decision on Powerlink's revenue for 2017–22 to its proposed revenue and to the revenue allowed and recovered during the two previous regulatory control periods of 2007–12 and 2012–17.

Figure 2.1 Powerlink's past total revenue, proposed total revenue and AER draft decision total revenue allowance ($million, 2016–17)



Source: AER analysis.

2.1 What is driving allowed revenue?

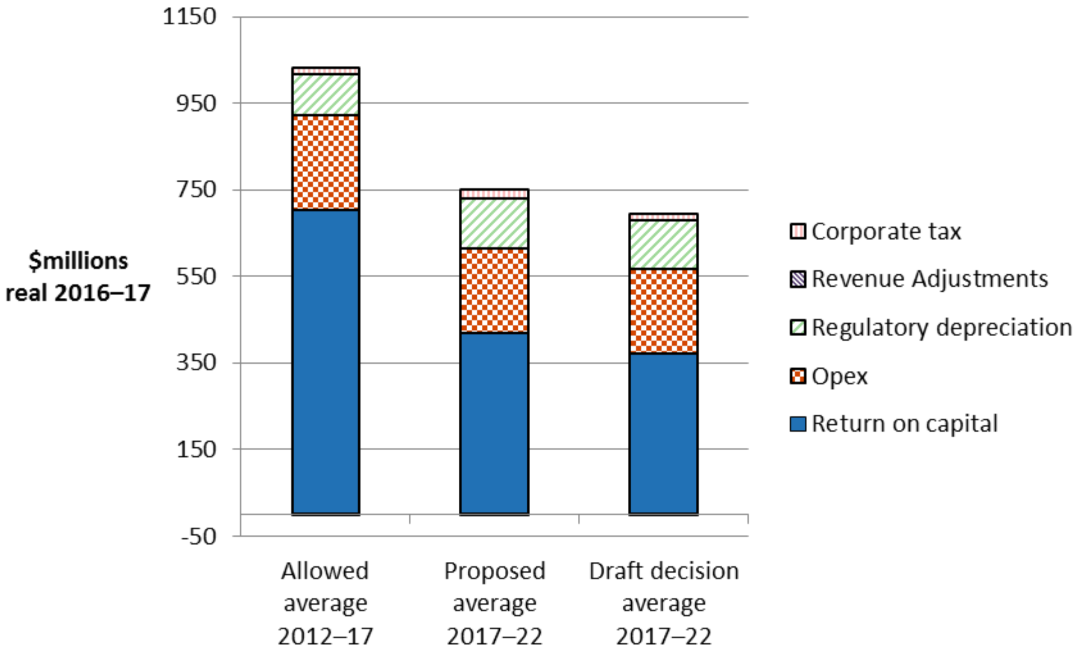
Our draft decision approves average annual revenues for the 2017–22 regulatory control period that are $281.2 million ($2016–17)—or 28.9 per cent—lower than was approved in our decision for 2012–17 in real dollar terms.[2] Our draft decision provides for 7.4 per cent less revenue than Powerlink sought to recover through its revenue proposal. Of this reduction, 5.8 per cent can be attributed to our adjustments to Powerlink's proposed rate of return, 0.8 per cent can be attributed to our adjustments

2 In nominal dollar terms, our draft decision average annual revenues for the 2017–22 regulatory control period is about $191.7 million (or 20.5 per cent) lower than the average annual revenues approved for the 2012–17 regulatory control period.

to Powerlink's proposed capex, and 0.7 per cent can be attributed to our adjustments to Powerlink's opening RAB.

Figure 2.2 compares the average annual building block revenue from our draft decision to that proposed by Powerlink for the 2017–22 regulatory control period, and to the approved average amount for the 2012–17 regulatory control period.

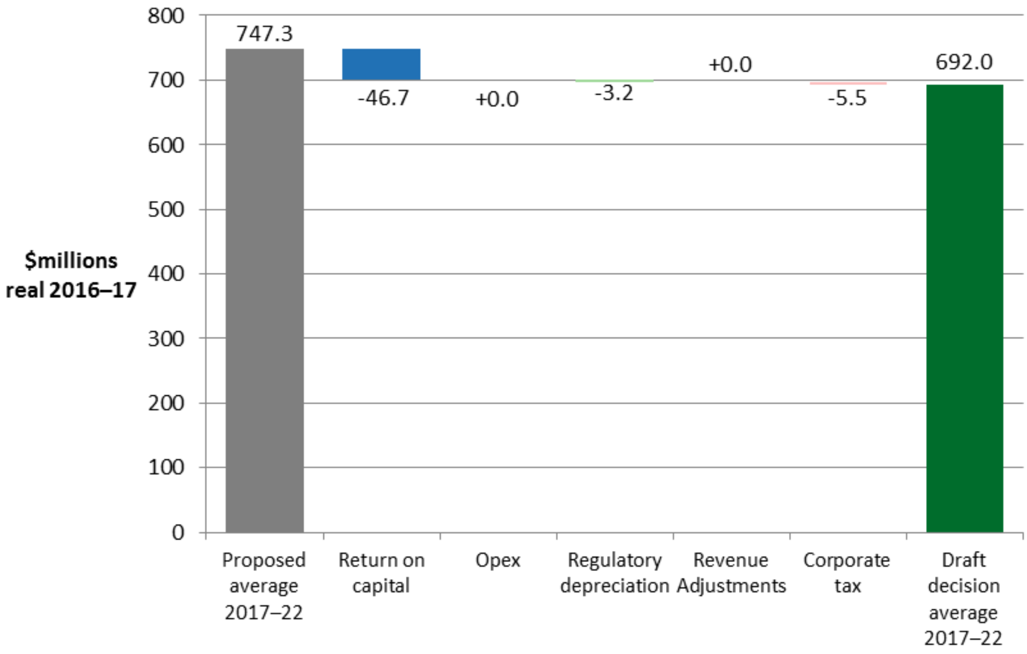
Figure 2.2 AER's draft decision on constituent components of total revenue ($million, 2016–17)



Source: AER analysis.

Figure 2.3 compares our draft decision with Powerlink's proposal, broken down by the various building block components that make up the forecast revenue allowance. These are annual amounts based on an average over the five year regulatory control period.

Figure 2.3 AER's draft decision and Powerlink's proposed annual building block costs ($million, 2016–17)



Source: AER analysis.

These figures highlight that the return on capital is the key difference between our draft decision and Powerlink's proposal. Our draft decisions on the allowed rate of return and allowed capital expenditure (capex) largely drive this difference.

2.1.1 Allowed rate of return

The allowed rate of return provides Powerlink with revenue to service the interest on its loans and give a return on equity to its shareholders. It is applied to Powerlink's capital base to determine the return on capital building block.

We set out our approach to determining the rate of return in the Rate of Return Guideline (Guideline) we published in December 2013. We undertook significant consultation in developing this Guideline. In its proposal, Powerlink proposed to use the methodology set out in our Guideline. After considering the information before us in Powerlink's proposal and in submissions, we have accepted the approach proposed by Powerlink for calculating the rate of return. Nevertheless, the approach to calculating the rate of return in Powerlink's proposal requires us to consider prevailing market conditions.

Prevailing market conditions for debt and equity are subject to change and heavily influence the rate of return. Financial conditions have changed since Powerlink submitted its proposal. Interest rates are lower, meaning that the cost of debt and the returns required to attract equity are lower. These factors result in a rate of return lower than Powerlink proposed in its draft decision.

Our draft decision is for a rate of return of 5.48 per cent (for 2017–18). This compares with Powerlink's proposed 6.04 per cent in its revenue proposal, and the 8.61 per cent set for the 2012–17 regulatory control period. In our final decision we will update the rate of return again, having regard to the prevailing market conditions at the time we make our final decision and by reference to the averaging periods that Powerlink nominated in its proposal.

2.1.2 Allowed capital expenditure

We had concerns involving some aspects of Powerlink's forecasting methodology and key assumptions which are material to our view that we are not reasonably satisfied that its proposed total forecast capex reasonably reflects the capex criteria.

Powerlink's capex forecasting methodology primarily relies on a top-down approach to forecast asset replacement requirements using a modified version of the AER's repex model. This model relies on using asset age as a proxy for the many factors that influence individual asset replacements. Powerlink has calibrated and adjusted the repex model inputs based on its actual asset replacement expenditure in the period from 2010 to 2015.

In recent years, Powerlink has implemented a number of improvement initiatives and continues to review, revise and improve its asset management strategies. However, we are concerned that Powerlink's historical asset replacement policies and practices, particularly in the early years of the calibration period, are likely to distort the repex model calibration and result in average asset replacement lives which are shorter than Powerlink is actually likely to achieve in the 2017–22 regulatory control period.

Based on Powerlink's historical repex project documentation and actual project outcomes, it is clear that the actual survival lives of assets achieved by Powerlink are typically longer than Powerlink has assumed in its repex model. We are therefore not satisfied that the inputs and assumptions which underpin Powerlink's use of the repex model are likely to result in a capex forecast which reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives. Our assessment of Powerlink's repex is discussed further in section 3.5 and attachment 6.

2.2 Expected impact of decision on electricity bills

Transmission charges account for a relatively small percentage of a residential customers' annual electricity bill. The annual electricity bill for customers in Queensland will reflect the combined cost of all the electricity supply chain components—wholesale energy generation, transmission, distribution, metering, and retail costs. On average, transmission charges account for approximately 9.3 per cent of a Queensland customer's annual electricity bill. This small percentage largely explains the relatively modest average annual electricity bill impacts arising from our draft decision.

We estimate the expected bill impact by varying the transmission charges in accordance with our draft decision, while holding other components of the bill constant. This approach isolates the effect of our decision on electricity prices, but does not imply that other components will remain unchanged across the regulatory control period.[3]

Based on this approach, we expect that our draft decision will result in the transmission component of the average annual residential electricity bills in Queensland to decrease moderately over the 2017–22 regulatory control period. The transmission component of the average annual residential electricity bill in 2021–22 is expected to reduce by about $40 ($ nominal) or 2.5 per cent below the 2016–17 level.

By comparison, had we accepted Powerlink's proposal, the expected transmission component of the average annual residential electricity bill in 2021–22 would reduce by about $31 ($ nominal) or 1.9 per cent below the 2016–17 level.

Table 2.1 shows the estimated impact of our draft decision on average residential and small business customers' annual electricity bills in Queensland over the 2017–22 regulatory control period, compared with Powerlink's proposal. As explained above, these bill impact estimates are indicative only, and individual customers' actual bills will depend on their usage patterns and the structure of their chosen retail tariff offering.

Table 2.1 Estimated impact of draft decision on average Queensland residential and small business customers' electricity bills for 2017–22 period ($nominal)

	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
AER draft decision						
Residential annual bill	1611[a]	1562	1564	1566	1569	1571
Annual change[c]		–49 (–3.1%)	2 (0.1%)	2 (0.1%)	3 (0.2%)	2 (0.1%)
Small business with 10 000 kWh consumption annual bill	3014[b]	2921	2925	2930	2935	2939
Annual change[c]		–93 (–3.1%)	4 (0.1%)	4 (0.1%)	6 (0.2%)	4 (0.1%)
Small business with 20 000 kWh consumption annual bill	5249[b]	5088	5094	5102	5112	5119
Annual change[c]		–161 (–3.1%)	7 (0.1%)	7 (0.1%)	10 (0.2%)	7 (0.1%)
Powerlink proposal						
Residential annual bill	1611[a]	1570	1572	1574	1578	1580
Annual change[c]		–41 (–2.6%)	2 (0.1%)	2 (0.2%)	3 (0.2%)	2 (0.1%)
Small business with 10 000 kWh consumption annual bill	3014[b]	2936	2941	2945	2951	2956

3 It also assumes that actual energy demand will equal the forecast in our draft decision. Since Powerlink operates under a revenue cap, changes in demand will also affect annual electricity bills across the 2017–22 regulatory control period.

	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Annual change[c]		–78 (–2.6%)	4 (0.1%)	5 (0.2%)	6 (0.2%)	4 (0.1%)
Small business with 20 000 kWh consumption annual bill	5249[b]	5114	5121	5129	5139	5147
Annual change[c]		–135 (–2.6%)	7 (0.1%)	8 (0.2%)	10 (0.2%)	8 (0.1%)

Source: AER analysis; AEMC, *2015 Residential electricity price trends*, December 2015, p. 105; and Powerlink, *Revenue proposal*, PTRM, January 2016.

(a) Based on Powerlink, *Revenue proposal*, consolidated Reset RIN, January 2016, checked against offers at June 2016 from the Energy made easy website (postcode:4000, 4810) using consumption of 5173 kWh per annum.

(b) Based on Powerlink, *Revenue proposal*, consolidated Reset RIN, January 2016.

(c) Annual change amounts and percentages are indicative. They are derived by varying the transmission component of 2016–17 bill amounts in proportion to yearly expected revenue divided by Powerlink's forecast demand. Actual bill impacts will vary depending on electricity consumption and tariff class.

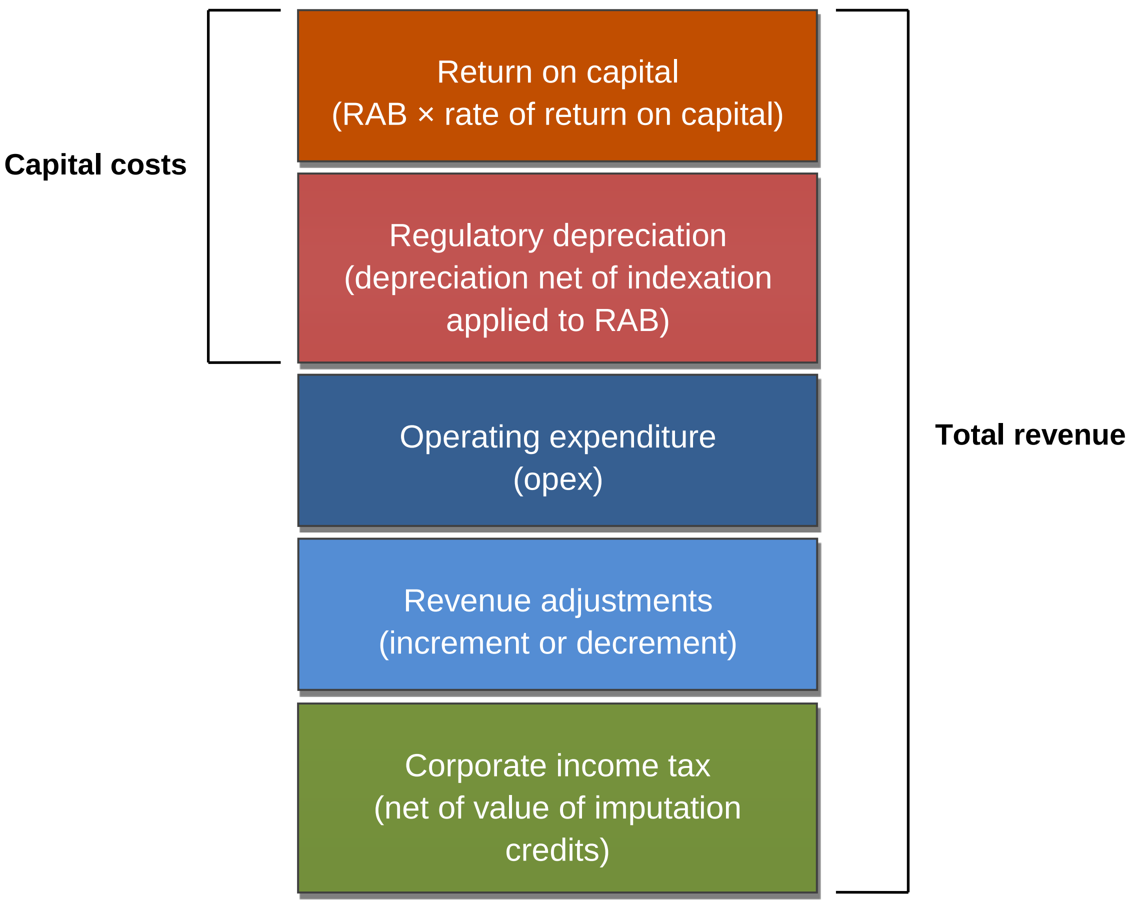
3 Key elements of our draft decision

We use the building block approach to determine Powerlink's maximum allowed revenue (MAR). The building block approach consists of five costs that a business is allowed to recover through its revenue allowance.

The building block costs are illustrated in Figure 3.1 and include:

- a return on the regulatory asset base (RAB) (or return on capital)
- depreciation of the RAB (or return of capital)
- forecast opex
- revenue increments or decrements resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

Figure 3.1 The building block approach for determining total revenue



The building block costs are comprised of key elements that we determine through our assessment process. For example, the size of the RAB—and therefore the revenue generated from the return on capital and regulatory depreciation building blocks—is directly affected by our assessment of forecast capex.

This section summarises our draft decision on key elements of the building blocks including:

- RAB (section 3.1)
- Rate of return (section 3.2)
- Imputation credits (section 3.3)
- Depreciation allowance (section 3.4)
- Efficient level of capex (section 3.5)
- Efficient level of opex (section 3.6)
- Forecast level of corporate income tax (section 3.7).

Incentive schemes including the EBSS and CESS are covered in chapter 4. Table 3.1 shows our draft decision on Powerlink's revenues including the building block components.

Table 3.1 AER's draft decision on Powerlink's revenues ($million, nominal)

	2017–18	2018–19	2019–20	2020–21	2021–22	Total
Return on capital	392.3	396.1	399.3	401.8	404.0	1993.5
Regulatory depreciation[a]	93.4	108.2	125.1	136.6	142.5	605.8
Operating expenditure[b]	201.7	205.8	209.8	214.2	219.3	1050.7
Revenue adjustments[c]	–0.8	–7.1	–3.2	3.0	0.0	–8.1
Net tax allowance	11.7	14.2	17.7	19.2	19.3	82.2
Annual building block revenue requirement (unsmoothed)	698.3	717.2	748.8	774.8	785.1	3724.2
Annual expected MAR (smoothed)	**710.8**	**727.1**	**743.8**	**760.9**	**778.3**	**3720.8**[d]
X factor[e]	n/a[f]	0.15%	0.15%	0.15%	0.15%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Operating expenditure includes debt raising costs.

(c) Includes efficiency benefit sharing scheme amounts.

(d) The estimated total revenue cap is equal to the total annual expected MAR.

(e) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(f) Powerlink is not required to apply an X factor for 2017–18 because we set the 2017–18 MAR in this decision. The MAR for 2017–18 is around 32.6 per cent lower than the approved MAR for 2016–17 in real terms, or 30.9 per cent lower in nominal terms.

3.1 Regulatory asset base

We make a decision on Powerlink's opening regulatory asset base (RAB) at 1 July 2017 as part of our revenue determination. We also make a decision on Powerlink's projected RAB for the 2017–22 regulatory control period.[4]

The RAB roll forward accounts for the value of Powerlink's regulated assets over the regulatory control period. The size of the RAB substantially impacts Powerlink's revenue and the price consumers ultimately pay. It is an input into the determination of the return on capital and depreciation (return of capital) building blocks.[5] Other things being equal, a higher RAB increases both the return on capital and depreciation allowances. In turn, these increase Powerlink's revenue, and prices for services.

We do not accept Powerlink's proposed opening RAB of $7237.9 million ($ nominal) as at 1 July 2017.[6] We instead determine an opening RAB value of $7164.7 million ($ nominal) as at 1 July 2017. This is because we have amended Powerlink's proposed roll forward model (RFM) to correct two input errors and made one update. These amendments relate to:

- updating the 2015–16 inflation rate with actual CPI for RAB indexation
- correcting an input error for the movements in capitalised provisions, which are adjusted from actual capex being added to the RAB
- correcting an input error for the benchmark equity raising costs in 2012–13.

These amendments reduced the opening RAB as at 1 July 2017 by $73.2 million (or 1.0 per cent) compared to the proposal.

To determine the opening RAB as at 1 July 2017, we have rolled forward the RAB over the 2012–17 regulatory control period to determine a closing RAB value at 30 June 2017. This roll forward includes an adjustment at the end of the 2012–17 regulatory control period to account for the difference between actual 2011–12 capex and the estimate approved at the 2012–17 determination.[7]

Table 3.2 summarises our draft decision on the roll forward of Powerlink's RAB over the 2012–17 regulatory control period.

Table 3.2 AER's draft decision on Powerlink's RAB for the 2012–17 regulatory control period

	2012–13	2013–14	2014–15	2015–16[a]	2016–17[b]

[4] NER, cl. 6A.6.1.

[5] The size of the RAB also impacts the benchmark debt raising cost allowance. However, this amount is usually relatively small and therefore not a significant determinant of revenues overall.

[6] This RAB value is based on as-incurred capex.

[7] The end of period adjustment will be positive (negative) if actual capex is higher (lower) than the estimate approved at the 2012–17 determination.

Opening RAB	6428.8	6847.9	7149.0	7152.5	7142.2
Capital expenditure[c]	464.3	329.1	163.8	166.7	220.6
Inflation indexation on opening RAB[d]	160.9	200.6	95.1	93.7	175.0
Less: straight-line depreciation[e]	206.0	228.7	255.3	270.7	276.6
Closing RAB	6847.9	7149.0	7152.5	7142.2	7261.2
Difference between estimated and actual capex (1 July 2011 to 30 June 2012)					–65.5
Return on difference for 2011–12 capex					–31.1
Opening RAB as at 1 July 2017					**7164.7**

Source: AER analysis.

(a) Based on estimated capex. We will update the RAB roll forward for actual capex in the final decision.

(b) Based on estimated capex provided by Powerlink. We expect to update the RAB roll forward with a revised capex estimate in the final decision, and true-up the RAB for actual capex at the next reset.

(c) As-incurred, net of disposals, and adjusted for actual CPI.

(d) We will update the RAB roll forward for actual CPI for 2016–17 in the final decision.

(e) Adjusted for actual CPI. Based on actual as-commissioned capex.

We determine a forecast closing RAB value at 30 June 2022 of $7402.9 million ($ nominal). This is $259.6 million (or 3.4 per cent) lower than the amount of $7662.5 million ($ nominal) proposed by Powerlink. Our draft decision on the forecast closing RAB reflects the amended opening RAB as at 1 July 2017, and our draft decisions on the expected inflation rate (attachment 3), forecast capex (attachment 6) and forecast depreciation (attachment 5).

Table 3.3 sets out our draft decision on the forecast RAB values for Powerlink over the 2017–22 regulatory control period.

Table 3.3 AER's draft decision on Powerlink's RAB for the 2017–22 regulatory control period ($million, nominal)

	2017–18	2018–19	2019–20	2020–21	2021–22
Opening RAB	7164.7	7234.4	7293.3	7338.3	7377.7
Capital expenditure[a]	163.1	167.0	170.2	175.9	167.7
Inflation indexation on opening RAB	175.5	177.2	178.7	179.8	180.8
Less: straight-line depreciation[b]	268.9	285.4	303.8	316.4	323.3
Closing RAB	7234.4	7293.3	7338.3	7377.7	7402.9

Source: AER analysis.

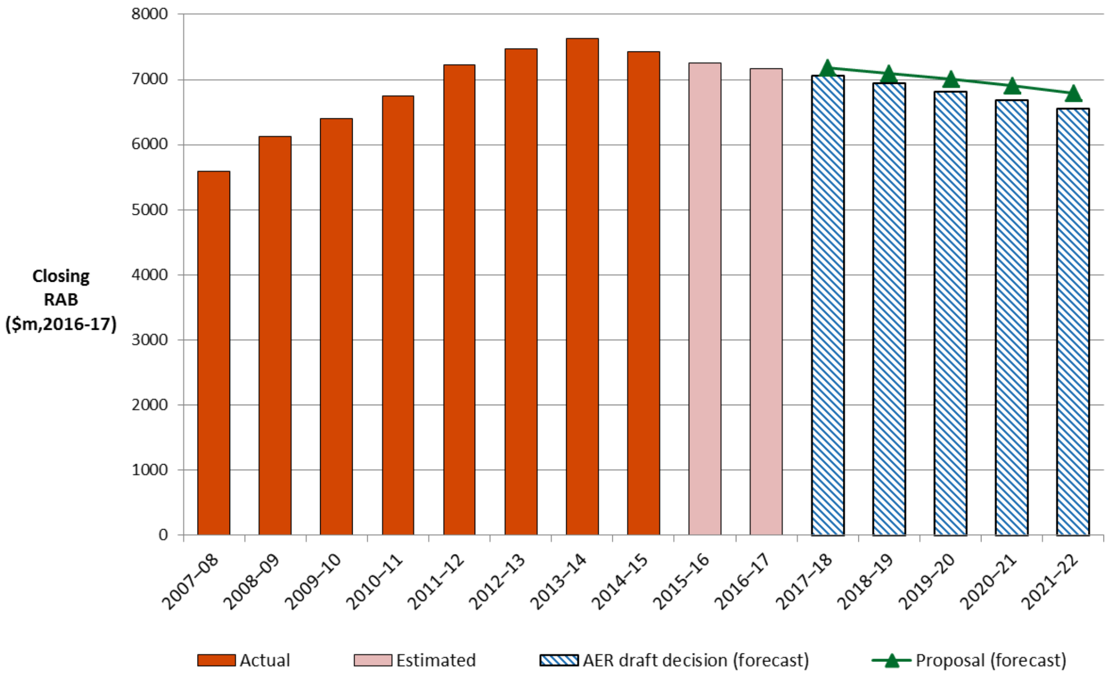
(a) As incurred and net of forecast disposals. In accordance with the timing assumptions of the post-tax revenue model (PTRM), the capex includes a half-WACC allowance to compensate for the six month period before capex is added to the RAB for revenue modelling.

(b) Based on as-commissioned capex.

We determine that the forecast depreciation approach is to be used to establish the opening RAB at the commencement of the 2022–27 regulatory control period for Powerlink.[8] We consider this approach will provide sufficient incentives for Powerlink to achieve capex efficiency gains over the 2017–22 regulatory control period. Powerlink is not currently subject to a capital expenditure sharing scheme (CESS). As explained in section 4.2, we will apply the CESS to Powerlink for the 2017–22 regulatory control period.

Figure 3.2 compares our draft decision on Powerlink's forecast RAB to Powerlink's proposal and actual RAB in real dollar terms. The RAB is expected to decline over the 2017–22 regulatory control period.

Figure 3.2 Powerlink's actual RAB, proposed forecast RAB and AER draft decision forecast RAB ($ million, 2016–17)



Source: AER analysis.

When making our draft decision on Powerlink's RAB we had regard to the submissions from Consumer Challenge Panel (CCP) members Hugh Grant and David Headberry on a number of RAB-related issues.[9] The CCP members submitted that Powerlink's

8 NER, cl. S6A.2.2B(a).

9 CCP (Hugh Grant and David Headberry), *Submission to the AER, Powerlink Queensland 2018–22 revenue proposal*, 20 June 2016, and CCP (Hugh Grant), *The methodology for the comparison of the electricity networks' return on equity with the returns of ASX 50 companies—in the context of the Powerlink/Telstra comparison*, 26 July 2016

overall 'extraordinary profitability levels' were a result of the AER's approach to RAB assessment; and interactions between the return *on* capital and return *of* capital allowances (sections 3.2 and 3.4 below).[10] We have carefully reviewed this material, but do not consider that the CCP members' analysis demonstrates our approach to these building blocks is incorrect. Most importantly, we consider that our approach to RAB indexation is compatible with our approach to the rate of return on capital. Jointly, these approaches produce appropriate revenue allowances over the life of the assets in the RAB. We agree that there is some merit to the analysis of profitability outcomes, although this is contingent on the availability of reliable data.

Further detail on our draft decision in regards to Powerlink's RAB (and our response to CCP members' submissions on capital issues) is set out in attachment 2.

3.2 Rate of return (return on capital)

The allowed rate of return provides a TNSP a return on capital to service the interest on its loans and give a return on equity to investors. The return on capital building block is calculated as a product of the rate of return and the value of the RAB.

We are satisfied that the allowed rate of return of 5.48 per cent (nominal vanilla) we have determined achieves the allowed rate of return objective (ARORO).[11] That is, we are satisfied that this allowed rate of return is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to Powerlink in providing prescribed transmission services.[12]

This allowed rate of return of 5.48 per cent will apply to Powerlink for 2017–18. A different rate of return value will apply to Powerlink for the remaining regulatory years of the 2017–22 regulatory period. This is because we will update the return on debt component each year to partially reflect the prevailing debt market conditions. We discuss this annual update further below.

Our allowed rate of return is a weighted average of our return on equity and return on debt estimates determined on a nominal vanilla basis that is consistent with our estimate of the value of imputation credits. We are to determine the allowed rate of return such that it achieves the ARORO. Also, in arriving at our decision we have taken into account the revenue and pricing principles (RPPs) and are also satisfied that our decision will or is likely to contribute to the achievement of the National Electricity Objective (NEO).

We have determined our rate of return based on the methodology set out in our Rate of Return Guideline (Guideline). Powerlink adopted our Guideline approach in its

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10 CCP (Hugh Grant and David Headberry), *Submission to the AER, Powerlink Queensland 2018–22 revenue proposal*, 20 June 2016, p. 41.

11 NER, cl. 6A.6.2(b).

12 NER, cl. 6A.6.2(c).

regulatory proposal,[13] but noted it does not endorse our methods and submitted three consultant reports supporting departures from our Guideline.[14]

We have accepted Powerlink's proposal to apply our Guideline (although components have been updated to account for prevailing market conditions) but do not agree with Powerlink that departures from our Guideline may better achieve the ARORO.

Table 3.4 sets out our rate of return and Powerlink's proposed rate of return.

Table 3.4 AER draft decision on Powerlink's rate of return (% nominal)

	AER previous decision (2012–17)	Powerlink proposal (2017–18)	AER draft decision (2017–18)	Allowed return over 2017–22 regulatory control period
Return on equity (nominal post–tax)	9.37	7.30	6.50	Constant (6.5%)
Return on debt (nominal pre–tax)	8.10	5.20	4.79	Updated annually
Gearing	60	60	60	Constant (60%)
Nominal vanilla WACC	8.61	6.04	5.48	Updated annually for return on debt
Forecast inflation	2.60	2.45	2.45	Constant (2.45%)

Source: AER analysis; Powerlink, *2018–2022 Powerlink Queensland revenue proposal*, 28 January 2016; AER, *Final Decision: Powerlink Transmission determination 2012-13 to 2016-17*, April 2012, p. 33.

Our return on equity estimate is 6.5 per cent. This rate will apply to Powerlink in each regulatory year. Our return on debt estimate for the 2017–18 regulatory year is 4.79 per cent. This estimate will change each year as we partially update the return on debt to reflect prevailing interest rates over Powerlink's debt averaging period in each year. Our return on debt estimate for future regulatory years will be determined in accordance with the methodology and formulae we have specified in this decision. As a result of updating the return on debt each year, the overall rate of return and Powerlink's revenue will also be updated.

We accept Powerlink's application of our Guideline return on equity approach. We have applied this approach and updated it for prevailing market conditions. We note that the Australian Competition Tribunal (Tribunal) recently upheld the use of our Guideline approach for estimating return on equity.[15]

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[13] Powerlink, *2018–2022 Powerlink Queensland revenue proposal*, 28 January 2016, pp. 90–91.

[14] Powerlink, *2018–2022 Powerlink Queensland revenue proposal*, 28 January 2016, p. 92; Frontier Economics, *The required return on equity under the AER's rate of return guideline, Report prepared for Powerlink*, January 2016; Frontier Economics, *Regulatory estimation of gamma, Report prepared for Powerlink*, January 2016; Queensland Treasury Corporation, *Return on debt transition analysis for Powerlink*, December 2015.

[15] For example, see Australian Competition Tribunal, *Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1*, 26 February 2016, para 717.

Our return on equity point estimate and the parameter inputs are set out in Table 3.5.

Table 3.5 AER draft decision on Powerlink's return on equity (nominal)

	AER previous decision (2012–17)	Powerlink proposal (2017-22)[a]	AER draft decision (2017–22)
Nominal risk free rate (return on equity only)	4.17%	2.72%	1.95%
Equity risk premium	5.20%	4.55%	4.55%
Market risk premium	6.50%	6.50%	6.50%
Equity beta	0.8	0.7	0.7
Nominal post–tax return on equity	9.37%	7.3%	6.50%

Source: AER analysis; Powerlink, *2018–2022 Powerlink Queensland revenue proposal*, 28 January 2016; AER, *Final Decision: Powerlink Transmission determination 2012-13 to 2016-17*, April 2012, p. 33.

(a) Powerlink used an indicative averaging period of 20 business days to 15 September 2015.

We accept Powerlink's application of our Guideline return on debt approach and of our proposed transitional trailing average approach used in our most recent decisions.[16] That is to:

- estimate the return on debt using an on-the-day approach (that is, based on prevailing market conditions near the commencement of the regulatory period) in the first year (2017–18) of the 2017–22 regulatory period, and
- gradually transition this approach into a trailing average approach (that is, a moving historical average) over 10 years.[17]

This gradual transition occurs through updating 10 per cent of the entire return on debt each year to reflect prevailing market conditions in that year (a full transition).[18]

In the Guideline, we proposed to use one or more third party data series to estimate the return on debt.[19] At that time, however, we had not formed a view on which data series to use. Our April 2014 issues paper outlined how we would make this choice

16 Powerlink, *2018–2022 Powerlink Queensland revenue proposal*, 28 January 2016, p. 91.

17 This draft decision determines the return on debt methodology for the 2017-22 regulatory period. This period covers the first five years of the 10 year transition period. This decision also sets out our intended return on debt methodology for the remaining five years. However, we do not have the power to determine in this decision the return on debt methodology for those years. Under the NER, the return on debt methodology must be determined in future decisions that relate to that period.

18 By entire return on debt, we mean 100% of the base rate and debt risk premium components of the allowed return on debt.

19 AER, *Explanatory statement—Rate of return guideline*, December 2013, pp. 23–24.

and sought submissions from service providers.[20] Following our recent decisions, Powerlink proposed we use a simple average of the RBA and Bloomberg data series.[21]

Consequently, the return on debt in each regulatory year is estimated with reference to:

- a benchmark credit rating of BBB+
- a benchmark term of debt of 10 years
- independent third party data series—specifically, a simple average of the broad BBB rated debt data series published by the Reserve Bank of Australia (RBA) and Bloomberg, adjusted to reflect a 10 year estimate and other adjustments[22]
- an averaging period for each regulatory year of between 10 business days and 12 months (nominated by the service provider), with that period being consistent with certain conditions that we proposed in the Guideline.[23]

It is worth noting that the Tribunal recently reviewed several aspects of our approach to estimating the allowed return on debt in recent decisions for ActewAGL, Jemena Gas Networks and Networks NSW. Specifically, the Tribunal was asked to review:

- Whether a benchmark efficient entity would have a credit rating of BBB rather than BBB+. It upheld our decision to define a benchmark credit rating as a BBB+ credit rating.[24]
- Whether we should estimate the allowed return on debt using the RBA data series alone or a simple average of the RBA and Bloomberg data series. It upheld our decision and found that, 'averaging of the two curves was an acceptable measure of the DRP [debt risk premium]'. [25]
- Whether we should transition all of the return on debt[26] from an on-the-day approach in the first regulatory year to a trailing average by updating 10 per cent of the debt portfolio over 10 years (a full transition). It remitted the determination back to us to make a constituent decision on introducing the trailing average approach in

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20 AER, *Issues Paper - Return on debt: Choice of third party data service provider*, April 2014.

21 For example, see AER, *Final decision: AusNet Services determination 2015 -16 to 2019–20, Attachment 3—Rate of return*, May 2016.

22 For the RBA curve, our draft decision is to interpolate the monthly data points to produce daily estimates, to extrapolate the curve to an effective term of 10 years, and to convert it to an effective annual rate. For the Bloomberg curve, our draft decision is to extrapolate it to 10 years using the spread between the extrapolated RBA seven and 10 year curves (where Bloomberg has not published a 10 year estimate), and to convert it to an effective annual rate. While we do not propose estimating the return on debt by reference to the Reuters curve, we do not rule out including doing so in future determinations following a proper period of consultation.

23 AER, *Rate of return guideline*, December 2013, pp. 21–2; AER, *Explanatory statement—Rate of return guideline*, December 2013, p. 126.

24 For example, see Australian Competition Tribunal, *Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1*, 26 February 2016, para 993.

25 For example, see Australian Competition Tribunal, *Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1*, 26 February 2016, para 983.

26 For clarity, that is 100% of the base rate and debt risk premium components of the allowed return on debt.

accordance with several reasons outlined in its decision.[27] We note the Tribunal's decision in attachment 3.

Our formula for automatically updating the return on debt annually is set out in attachment 3 of this decision.

While Powerlink adopted our Guideline approach in its regulatory proposal, it also proposed that its allowed rate of return reflect any departures from the Guideline that we may apply in any remittal decisions that may result from current Tribunal and Federal Court processes.[28] While acknowledging that some matters relating to our Guideline are currently before the Tribunal and Federal Court for consideration, we consider that the rate of return set out in this decision achieves the ARORO and promotes the NEO and RPP.

We estimated expected inflation using the RBA's short term inflation forecasts and the mid-point of the RBA’s inflation targeting band. This is consistent with the approach we have applied since 2008 and the approach proposed by Powerlink.

Further detail on our draft decision in regards to Powerlink's allowed rate of return is set out in attachment 3.

3.3 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[29] These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore valuable to investors and are a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

However, the estimation of the return on equity does not take imputation credits into account. Therefore, an adjustment for the value of imputation credits is required. This adjustment could take the form of a decrease in the estimated return on equity itself. An alternative but equivalent form of adjustment, which is employed under the NER, is via the revenue granted to a service provider to cover its expected tax liability. Specifically, the NER requires that the estimated cost of corporate income tax be determined in accordance with a formula that reduces the estimated cost of corporate tax by the 'value of imputation credits' (represented by the Greek letter, γ, 'gamma'). This form of adjustment recognises that it is the payment of corporate tax which is the source of the imputation credit return to investors.

[27] For example, see Australian Competition Tribunal, *Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1*, 26 February 2016, para 1,227. The Tribunal's reasons are set out in paras 870 to 940.

[28] Powerlink, *2018–2022 Powerlink Queensland revenue proposal,* 28 January 2016, p. 93; Powerlink, *Powerlink 2018–22 revenue proposal: rate of return and value of imputation credits (gamma)*, 28 April 2016, pp. 1–2.

[29] *Income Tax Assessment Act 1997,* parts 3–6.

Our draft decision accepts Powerlink's proposed value of imputation credits (or gamma) of 0.4. We consider that the use of a value for imputation credits of 0.4 will result in equity investors in the benchmark efficient entity receiving an ex ante total return (inclusive of the value of imputation credits) commensurate with the efficient equity financing costs of a benchmark efficient entity.

We note Powerlink's submission that proposes that any resultant changes in the AER's approach to estimating gamma, as a result of the recent Tribunal decision, should apply to Powerlink's 2018-22 regulatory period.[30] However, we note that since the decisions for Ausgrid and others released in April 2015 we have not departed from our 0.4 estimate for gamma and we consider the 0.4 gamma estimate is appropriate for the reasons stated in this draft decision. However, if we are required to, or do, use a different gamma estimate as a result of any merits or judicial review proceedings before Powerlink's final decision is released, the AER will have regard to this in determining the value for gamma to be applied to Powerlink in its final decision.

In coming to a value of imputation credits of 0.4:

- we adopt a conceptual approach consistent with the Officer framework, which we consider best promotes the objectives and requirements of the NER/NGR. This approach considers the value of imputation credits is a post-tax value before the impact of personal taxes and transaction costs.[31] As such, we view the value of imputation credits as the proportion of company tax returned to investors through the utilisation of imputation credits[32]
- we consider our conceptual approach allows for the value of imputation credits to be estimated on a consistent basis with the allowed rate of return and allowed revenues under the post-tax framework in the NER/NGR[33]
- we use the widely accepted approach of estimating the value of imputation credits as the product of two sub-parameters: the 'distribution rate' and the 'utilisation rate'. Our definition of, and estimation approach for, these sub-parameters is set out in Table 3.6.

Table 3.6 Gamma sub-parameters: definition and estimation approach

Sub-parameter	Definition	Estimation approach
Distribution rate (or payout	The proportion of imputation credits	Primary reliance placed on the widely

30 Powerlink, *Submission on the rate of return and the value of imputation credit,* 28 April 2016.

31 Post-tax refers to after company tax and before personal tax.

32 This means one dollar of claimed imputation credits has a post (company) tax value of one dollar to investors before personal taxes and personal transaction costs.

33 In finance, the consistency principle requires that the definition of the cash flows in the numerator of a net present value (NPV) calculation must match the definition of the discount rate (or rate of return / cost of capital) in the denominator of the calculation (see Peirson, Brown, Easton, Howard, Pinder, *Business Finance*, McGraw-Hill, Ed. 10, 2009, p. 427). By maintaining this consistency principle, we provide a benchmark efficient entity with an ex ante total return (inclusive of the value of imputation credits) commensurate with the efficient financing costs of a benchmark efficient entity.

ratio)	generated that is distributed to investors	accepted cumulative payout ratio approach. Some regard is also given to Lally's estimate for listed equity from financial reports of the 20 largest listed firms.
Utilisation rate (or theta)	The utilisation value to investors in the market per dollar of imputation credits distributed[34]	A range of approaches, with due regard to the merit of each approach: • equity ownership approach • tax statistics • implied market value studies

Source: AER analysis.

Further detail on our draft decision in regards to the value of Powerlink's imputation credits is set out in attachment 4.

3.4 Regulatory depreciation (return of capital)

Depreciation is the allowance provided so capital investors recover their investment over the economic life of the asset (return of capital). In deciding whether to approve the depreciation schedules submitted by Powerlink, we make determinations on the indexation of the regulatory asset base (RAB) and depreciation building blocks for Powerlink's 2017–22 regulatory control period.[35] The regulatory depreciation allowance is the net total of the RAB depreciation less the inflation indexation adjustment of the RAB.

We do not accept Powerlink's proposed regulatory depreciation allowance of $623.2 million ($ nominal) for the 2017–22 regulatory control period. Instead, we determine a regulatory depreciation allowance of $605.8 million ($ nominal) for Powerlink. This represents a decrease of $17.4 million (or 2.8 per cent) on the proposed amount. In coming to our draft decision:

- We accept Powerlink's proposed straight-line method, and standard asset lives used to calculate the regulatory depreciation allowance. We consider that Powerlink's proposed standard asset lives are consistent with those approved at the 2012–17 transmission determination and comparable to the standard asset lives used for other TNSPs. Accordingly, we consider the standard asset lives would lead to a depreciation schedule that reflects the nature of the assets over their economic lives.[36]
- We accept Powerlink's proposed weighted average method to calculate the remaining asset lives as at 1 July 2017. This is because the proposed method applies the approach as set out in the AER's roll forward model (RFM).

[34] In this decision we use the terms theta, utilisation value and utilisation rate interchangeably to mean the same thing.
[35] NER, cll. 6A.5.4(a)(1) and (3).
[36] NER, cl. 6A.6.3(b)(1).

- We made determinations on other components of Powerlink's proposal that also affect the forecast regulatory depreciation allowance— the opening RAB as at 1 July 2017 (attachment 2) and forecast capital expenditure (attachment 6).

Table 3.7 shows our draft decision on Powerlink's depreciation allowance for the 2017–22 regulatory control period.

Table 3.7 AER's draft decision on Powerlink's depreciation allowance for the 2017–22 period ($million, nominal)

	2017–18	2018–19	2019–20	2020–21	2021–22	Total
Straight-line depreciation	268.9	285.4	303.8	316.4	323.3	1497.8
Less: inflation indexation on opening RAB	175.5	177.2	178.7	179.8	180.8	892.0
Regulatory depreciation	**93.4**	**108.2**	**125.1**	**136.6**	**142.5**	**605.8**

Source: AER analysis.

Further detail on our draft decision in regards to depreciation is set out in attachment 5.

3.5 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of network services. Forecast capex feeds into the estimates of the return on capital and regulatory depreciation building blocks we use to determine a TNSPs total revenue requirement.

We are not satisfied that Powerlink's proposed total forecast capex of $959.7 million ($2016-17) for the 2017–22 regulatory control period reasonably reflects the capex criteria. We have substituted it with our estimate of Powerlink's total forecast capex for the 2017–22 regulatory control period. We are satisfied that our substitute estimate of $775.2 million ($2016–17) reasonably reflects the capex criteria.

Table 3.8 shows our decision compared to Powerlink's forecast.

Table 3.8 AER draft decision on Powerlink's total forecast capex ($million, 2016–17)

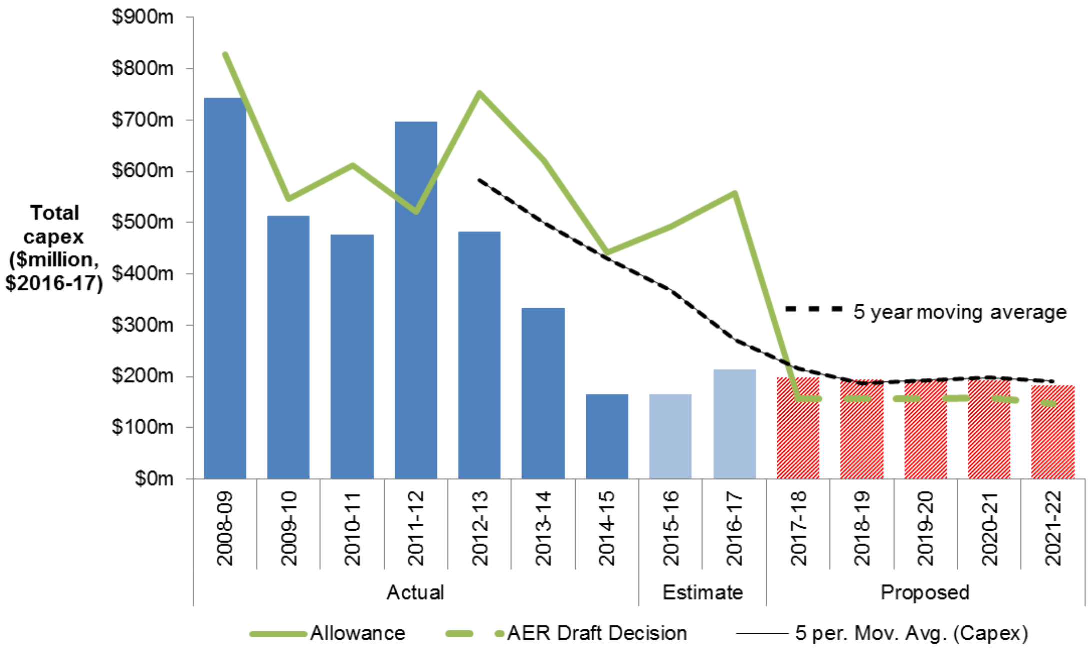
	2017–18	2018–19	2019–20	2020–21	2021–22	Total
Powerlink's proposal	198.6	194.7	191.9	192.8	181.8	959.7
AER draft decision	157.1	157.2	156.3	157.9	146.7	775.2
Difference	-41.4	-37.5	-35.6	-34.9	-35.0	-184.5
Percentage difference (%)	-20.9%	-19.3%	-18.5%	-18.1%	-19.3%	-19.2%

Source: Powerlink, *Capex model PUBLIC*, January 2016; AER analysis.

Note: Numbers may not total due to rounding.

Figure 3.3 shows our capex decision compared to Powerlink's proposal, its past allowances and past actual expenditure.

Figure 3.3 Powerlink total actual and forecast capex 2014–2022



Source: AER analysis.

Powerlink's capex proposal consists of $843.2 million for non-load driven capex, $10 million for augmentation capex, and $103.1 million for non-network capex. In our substitute estimate, we accept Powerlink's forecast for augmentation and non-network capex, but have substituted our own estimate for non-load driven capex.

Powerlink's non-load driven capex forecast consists of asset replacement ($794.3 million), security and compliance ($18.8 million), and other non-load driven capex ($30.1 million). Powerlink forecast the bulk of its asset replacement capex using a top-down approach that uses a modified version of the AER's repex model. This model relies on using asset age as a proxy for the many factors that influence individual asset replacements. Powerlink has calibrated and adjusted the repex model inputs using its actual expenditure from 2010 to 2015.

To assist our review of Powerlink's forecast, we engaged consultants to assess the prudency and efficiency of Powerlink's asset replacement forecast, including the forecasting methodology, inputs and assumptions. We also analysed Powerlink's forecast using our internal technical and engineering expertise.

Powerlink's forecast capex is 31% lower than its actual expenditure in the previous regulatory control period. The main reason for this reduction is low forecast demand growth. Queensland has transitioned from high to relatively flat demand growth over the last 5 years. Forecast low demand growth over the next 5 years means that

Powerlink requires very little augmentation capex ($11 million or 1% of total capex) for this period.

The focus of Powerlink's capex program is replacement capex. The majority of Powerlink’s repex forecast is based on a top-down forecasting approach which uses the age profile of its existing assets and applies the historical average asset replacement age to determine a forecast of replacement requirements for the 2017–22 regulatory control period.

While we consider that Powerlink’s forecasting methodology is generally reasonable, we have a number of concerns with how Powerlink has implemented its approach. In particular, we have concerns with Powerlink's forecast replacement age of assets. In the past, Powerlink replaced assets at an earlier point than other transmission businesses and earlier than we now believe was necessary in some cases. Powerlink itself has recognised this issue and has adjusted its asset reinvestment policies and practices to bring it more into line with industry best practice. The revisions we have made to the asset replacement lives used in Powerlink's repex model attempt to capture Powerlink's more recent practice.

We seek input from Powerlink and other stakeholders on the approach that we have adopted. We concluded that Powerlink's average asset lives used as an input to the repex model were shorter than Powerlink is likely to achieve in practice and therefore needed to be longer to produce a prudent and efficient capex forecast. This change has led us to substitute an amount of $609.8 million for asset replacement capex instead of Powerlink's forecast $794.3 million. This change accounts for all of the difference between our substitute forecast and Powerlink's proposed forecast of total capex.

Powerlink also proposed $590 million for seven contingent projects. We do not accept two of these projects (the North West Surat Basin Area project and the Southern Galilee Basin project) because we do not consider that the load growth Powerlink forecasted for these two projects will eventuate. We accept the remaining five projects as contingent projects but require to Powerlink to amend the trigger events proposed for these projects.

Further detail on our draft decision in regards to capex is set out in attachment 6.

3.6 Operating expenditure

Operating expenditure (opex) is the forecast of operating, maintenance and other non–capital costs incurred in the provision of prescribed transmission services.

Our draft decision is to accept Powerlink's opex forecast of $976.7 million ($2016–17) over the 2017–22 regulatory period. Powerlink's proposal is lower (in real terms) than its annual opex spend in the 2012–17 regulatory period.

To assess Powerlink's proposal, we developed an alternative estimate of Powerlink's efficient costs using our standard 'base-step-trend' approach.[37] This involves assessing whether the business' past expenditure is an efficient starting point for our estimate, and allowing for forecast growth in prices, output and productivity over the regulatory period.

Our benchmarking indicates Powerlink has not been operating as efficiently as other transmission businesses in the National Electricity Market (NEM). CCP members made a submission stating we should apply benchmarking to determine Powerlink's efficient base year opex.[38] However, our benchmarking of transmission businesses is not sufficiently robust to support an alternative forecast of base opex at this stage of its development. Our benchmarking is limited by the small sample size of transmission businesses in the NEM—among other things.

Powerlink acknowledged it has scope to be more efficient and included efficiency measures in its proposal that in effect reduce its base opex by 12.2 per cent. Powerlink made an efficiency adjustment to base year opex and includes efficiency gains made in the previous regulatory period. Powerlink stated its opex proposal maintains current levels of reliability while delivering real annual reductions in forecast opex.[39]

We included Powerlink's efficiency adjustments in our alternative estimate as an efficiency cut to base opex.

Our alternative estimate of forecast total opex is $994.7 million ($2016–17).[40] This is $18.0 million (1.8 per cent) higher than Powerlink's proposal.

Figure 3.4 shows our alternative estimate compared to Powerlink's proposal (which have we accepted), its past allowances and past actual expenditure.

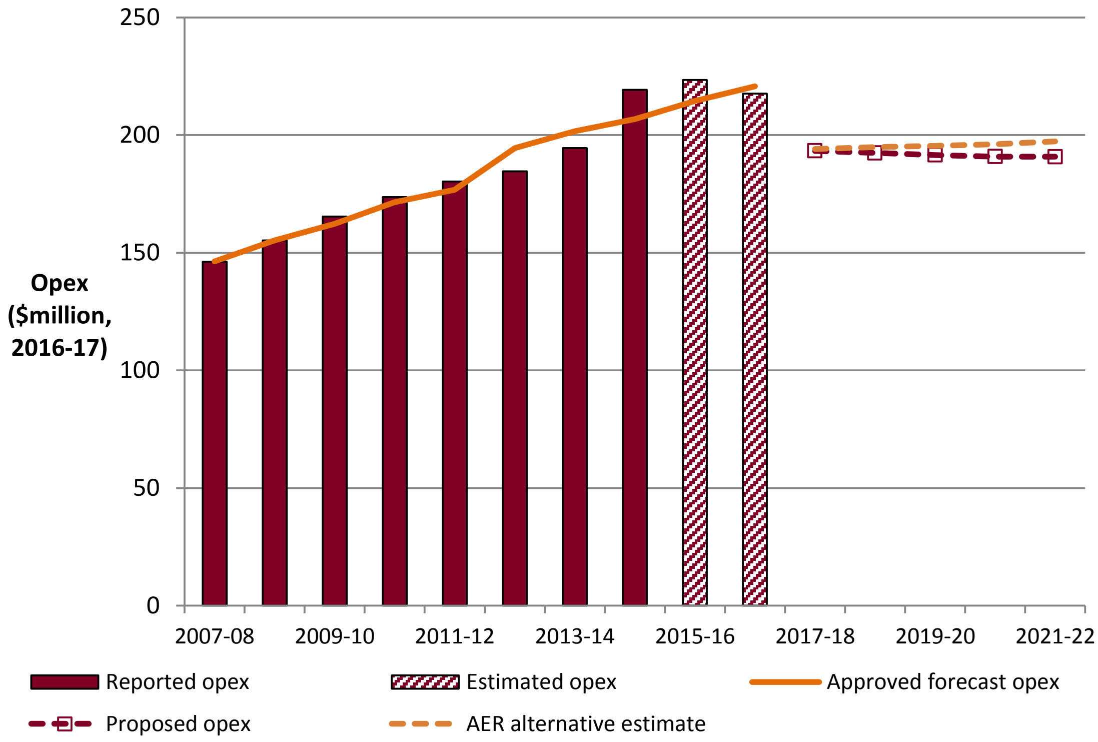
37 AER, *Better Regulation—Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

38 CCP (Hugh Grant and David Headberry), *Submission to the AER, Powerlink Queensland 2018–22 revenue proposal*, 20 June 2016, pp. 5–6.

39 Powerlink, *Revenue proposal*, 29 January 2016, p. 79.

40 Including debt raising costs.

Figure 3.4 AER draft decision on total forecast opex ($million, 2016–17)



Source: AER analysis.

The key difference between our estimate and Powerlink's forecast is different assumptions about productivity growth over 2017–22. Powerlink forecast higher productivity growth of 1.2 per cent. Our estimate includes productivity growth of 0.2 per cent, which is based on historical industry-wide trends—consistent with our standard approach. Powerlink states its forecast productivity gains are based on a detailed line-by-line assessment of potential efficiencies across its opex program. We accept Powerlink's judgement that it will be able to meet its forecast productivity improvements.

Further detail on our draft decision in regards to opex is set out in attachment 7.

3.7 Corporate income tax

We make a decision on the estimated cost of corporate income tax for Powerlink's 2017–22 regulatory control period as part of our revenue determination.[41] It enables Powerlink to recover the costs associated with the estimated corporate income tax payable during the regulatory control period.

We do not accept Powerlink's proposed cost of corporate income tax allowance of $111.5 million ($ nominal). Our draft decision on the estimated cost of corporate

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41 NER, cl. 6A.6.4.

income tax is $82.2 million ($ nominal) over the 2017–22 regulatory control period. This represents a reduction of $29.3 (or 26.2 per cent) from Powerlink's proposal.

The reduction reflects our amendments to some of Powerlink's proposed inputs for forecasting the cost of corporate income tax including the opening tax asset base (TAB), and the remaining tax asset lives. Changes to return on capital and regulatory depreciation building block costs affect revenues, which in turn impact the tax calculation. The changes affecting revenues are discussed in attachment 1.

Table 3.9 shows our draft decision on the estimated cost of corporate income tax allowance for Powerlink over the 2017–22 regulatory control period.

Table 3.9 AER's draft decision on Powerlink's cost of corporate income tax allowance for the 2017–22 regulatory control period ($million, nominal)

	2017–18	2018–19	2019–20	2020–21	2021–22	Total
Tax payable	19.5	23.7	29.6	31.9	32.2	137.0
Less: value of imputation credits	7.8	9.5	11.8	12.8	12.9	54.8
Net corporate income tax allowance	**11.7**	**14.2**	**17.7**	**19.2**	**19.3**	**82.2**

Source: AER analysis.

Further detail on our draft decision in regards to corporate income tax is set out in attachment 8.

4 Incentive schemes

Incentive schemes are a component of incentive–based regulation and complement our approach to assessing efficient costs. The incentive schemes that will apply to Powerlink are:

- the efficiency benefit sharing scheme (EBSS)
- the capital expenditure sharing scheme (CESS)
- the service target performance incentive scheme (STPIS).

Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced with the incentives under our STPIS. The incentive schemes encourage businesses to make efficient decisions on when and what type of expenditure to incur, and meet service reliability targets.

4.1 Efficiency benefit sharing scheme (EBSS)

The efficiency benefit sharing scheme (EBSS) provides a continuous incentive for service providers to pursue efficiency improvements in operating expenditure (opex).

To encourage a service provider to become more efficient, under an ex ante framework, a service provider retains any efficiency gains it makes until the end of the regulatory control period when its opex forecast is reset. The EBSS allows the service provider to retain any efficiency gains it makes for a total of six years, regardless of the year in which the gains are made.[42] This provides a continuous incentive for service providers to pursue efficiency gains over the regulatory control period. It also discourages a service provider from incurring opex in the expected base year to receive a higher opex allowance in the following regulatory control period.

During the 2012–17 regulatory control period, Powerlink operated under version one of the Electricity transmission network service providers' EBSS released in September 2007.[43]

Our draft decision is to approve the EBSS carryover amount of –$7.8 million ($2016–17) from the application of the EBSS in the 2012–17 regulatory control period, as proposed by Powerlink.

We note that Powerlink would receive a higher carryover of $1.2 million ($2016–17) if the EBSS calculations were adjusted to:

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[42] The service provider keeps any efficiency gain in the year it makes them. The service provider then keeps those gains for the length of the carryover period. The carryover length is usually five years so the service provider keeps efficiency gains for a total of six years.

[43] AER, *Electricity transmission network service providers, Efficiency benefit sharing scheme*, September 2007.

- share non-recurrent efficiency gains the same as other efficiency gains and losses
- use 2014–15 as the base year rather than 2015–16. Powerlink's EBSS calculations assume 2015–16 was used as the base year to forecast opex for the 2017–22 regulatory control period. However, Powerlink actually used 2014–15 to forecast opex. This inconsistency would effectively reward Powerlink twice for incremental efficiency gains made in 2015–16: once through the EBSS carryovers and a second time because they are not reflected in its opex forecast.

Also, Powerlink proposed not to retain efficiency gains it made after 2014–15 through either its proposed EBSS carryovers or its opex forecast.

Nevertheless, Powerlink maintains it is satisfied an EBSS carryover amount of –$7.8 million (penalty)—when considered together with an opex forecast of $976.7 million—appropriately recognises efficiency gains and losses in opex over the current regulatory period.

Our draft decision for the carryover amounts from the application of the EBSS in the 2012–17 regulatory control period is outlined in Table 4.1.

Table 4.1 AER's draft decision on Powerlink's EBSS carryover amounts ($million, 2016–17)

	2017-18	2018-19	2019-20	2020-21	2021-22	Total
Powerlink's proposed carryover	-0.8	-6.8	-3.0	2.8	-	-7.8
Draft decision	-0.8	-6.8	-3.0	2.8	-	-7.8

Source: AER analysis.

Our draft decision is to apply version two of the EBSS to Powerlink in the 2017–22 regulatory control period. This is consistent with our Final framework and approach paper and Powerlink's proposal.[44]

Further detail on our draft decision in regards to the application of the EBSS, including proposed expenditure items to be excluded, is set out in attachment 9.

4.2 Capital expenditure sharing scheme (CESS)

The CESS provides an incentive for service providers to pursue efficiency improvements in capex. Similar to the EBSS, the CESS provides a network service provider with the same reward for an efficiency saving and the same penalty for an efficiency loss regardless of which year they make the saving or loss.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of

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44 AER. *Final Framework and Approach for Powerlink: For the regulatory control period commencing 2017*, June 2015, pp. 21–24; Powerlink, *Revenue proposal*, January 2016, p. 111.

an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

We will apply the CESS as set out in version 1 of the capital expenditure incentives guideline to Powerlink in the 2017–22 regulatory control period.[45] The guideline provides for the exclusion from the CESS of capex the service provider incurs in delivering a priority project approved under the network capability component of the STPIS for transmission network service providers. This is consistent with the proposed approach we set out in our framework and approach paper.[46]

4.3 Service target performance incentive scheme (STPIS)

The STPIS is intended to balance a business' incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to businesses to maintain and improve service performance where customers are willing to pay for these improvements.

Businesses can only retain their rewards for sustained and continuous improvements to the reliability of supply for customers. Once improvements are made, the benchmark performance targets will be tightened in future years.

Our draft decision is to apply all components of version 5 of the STPIS to Powerlink for the 2017–22 regulatory control period. The STPIS parameters applied in our draft decision are set out in attachment 11.

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[45] AER, *Capex incentive guideline*, November 2013, pp. 5–9.

[46] AER, *Final Framework and Approach for Powerlink: For the regulatory control period commencing 2017*, June 2015, pp. 29–31.

5 The regulatory framework

The NEO is the central feature of the regulatory framework. The NEO is to:

> promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.[47]

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NEO.[48] The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[49]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.[50] We have also considered the quality and reliability of services provided to consumers. For example, opex allowances have been set so Powerlink may meet existing and new regulatory requirements. Replacement expenditure (repex) allowances take into account the age and condition of assets. Our capex allowance is based on a contemporary estimate of the value of customer reliability. The STPIS encourages maintenance, and indeed improvement of, service quality.

The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[51] At the same time, however, there are a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree that others would.

For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[52] This could have significant longer term pricing implications for those consumers who continue to use network services.

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47 NEL, section 7.

48 Hansard, *SA House of Assembly,* 9 February 2005, pp. 1451–1460; Hansard, *SA House of Assembly,* 27 September 2007, pp. 963–972; Hansard, *SA House of Assembly,* 26 September 2013, pp. 7171–7176.

49 Hansard, *SA House of Assembly,* 26 September 2013, p. 7173.

50 Hansard, *SA House of Assembly,* 9 February 2005, p. 1452.

51 Re Michael: Ex parte Epic Energy [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, *SA House of Assembly,* 26 September 2013, p. 7172.
AEMC*, Rule determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006, p. 50.

52 NEL, s. 7A(7).

Equally, we do not consider the NEO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network[53] and could have adverse consequences for safety, security and reliability of the network.

The NEL also includes the revenue and pricing principles (RPP),[54] which support the NEO. As the NEL requires,[55] we have taken the RPPs into account throughout our analysis.

> The RPPs are:
>
> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> – providing direct control network services; and
>
> – complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> – efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
>
> – the efficient provision of electricity network services; and
>
> – the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
>
> – in any previous—
>
> – as the case requires, distribution determination or transmission determination; or
>
> – determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or

53 NEL, s. 7A(6).

54 NEL, s. 7A.

55 NEL, s. 16(2).

– in the Rules.

> A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.
>
> Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

Consistent with Energy Ministers' views, we set revenue allowances to balance all elements of the NEO and consider each of the RPPs.[56] For example:

- In determining forecast opex and capex that reasonably reflects the opex and capex criteria, we take into account the revenue and pricing principle that should provide Powerlink with a reasonable opportunity to recover at least efficient costs. (Refer to capex attachment 6 and opex attachment 7).
- We take into account the economic costs and risks of the potential for under and over investment by a network service provider in our assessment of Powerlink's forecast capex and opex proposals. (Refer to capex attachment 6 and opex attachment 7).
- We consider the economic costs and risks of the potential for under and over utilisation of Powerlink's transmission system in our demand forecasting (Refer to capex attachment 6).
- Our application of the EBSS, CESS, and STPIS in this draft decision provide Powerlink with effective incentives which we consider will promote economic efficiency with respect to the direct control services that Powerlink provides throughout the regulatory control period. (Refer to attachments 9, 10 and 11).
- We have determined Powerlink's opening RAB taking into account the RAB adopted in the previous transmission determination. (Refer to attachment 2, regulatory asset base).
- The allowed rate of return objective reflects the revenue and pricing principle in s. 7A(5) of the NEL. We have determined a rate of return that we consider will provide Powerlink with a return commensurate with the regulatory and commercial risks involved in providing direct control services. (Refer to attachment 3, rate of return).

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[56] Hansard, *SA House of Assembly,* 27 September 2007, p. 965; Hansard, *SA House of Assembly,* 26 September 2013, p. 7173.

- Our financing determinations provide the TNSP with a reasonable opportunity to recover at least the efficient costs of accessing debt and capital. (Refer to attachment 3, rate of return).

In some cases, our approach to a particular component (or part thereof) results in an outcome towards the end of the range of options that may be favourable to the businesses. While it can be difficult to quantify the exact revenue impact of these individual decisions, we have identified where we have done so in our attachments. Some of these decisions include:

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in the post-tax revenue model.

We take into account the RPPs when exercising discretion about an appropriate estimate. This requires a recognition that for the long term interests of consumers, the risk of under compensation for, or underinvestment by, a service provider may be less desirable than the risk of overcompensation or overinvestment. However, the AER is also conscious of the risk of introducing an inherent bias towards higher amounts where estimates throughout the different components of the determination are each set too conservatively.[57] The legislative framework recognises the complexity of this task by providing the AER with significant discretion in many aspects of the decision-making process to make judgements on these matters.

Chapter 6A of the NER provides specifically for the economic regulation of TNSPs. It includes rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.[58]

5.1 Achieving the NEO to the greatest degree

Electricity transmission determinations are complex decisions and must be considered as such. In most instances, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. For example, chapter 6A of the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast.[59] There is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for certain components of our decision there may be several plausible answers or several plausible point estimates.

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57 AEMC, *Rule determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006, p. 52.

58 NEL, s. 88.

59 AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006,* 16 November 2006, p. 52.

When the constituent components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NEO. Where this is the case, our role is to make an overall decision that we are satisfied contributes to the achievement of the NEO to the greatest degree.[60]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives each of which would result in an overall decision that contributes to the achievement of the NEO, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree. This is our role under the NEO.

In coming to this draft decision we considered Powerlink's revenue proposal. We have examined each of the building block components of the initial proposal and the incentive mechanisms that would apply across the 2017–22 regulatory control period. We considered the submissions we received in regard to Powerlink's initial proposal. We conducted our own analysis and engaged expert consultants to help us better understand if and how Powerlink's initial proposal contributes to the achievement the NEO. We also considered how our constituent decisions relate to each other, the impact that particular constituent decisions have on other constituent components of our decision, and have described these interrelationships in this draft decision. We have undertaken an extensive and consultative regulatory review process to ensure we have canvassed stakeholder issues and made as much of this information publicly available as practicable. We have had regard to and weighed up all the information assembled before us in making this draft decision.

We are satisfied that among the options before us our draft decision on Powerlink's transmission determination for the 2017–22 regulatory control period contributes to the achieving the NEO to the greatest degree.

5.2 Interrelationships between constituent components

Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.[61] Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 6 and 7).

[60] NEL, s. 16(1)(d).

[61] SCER, *Regulation impact statement: Limited merits review of decision-making in the electricity and gas regulatory frameworks, Decision paper,* 6 June 2013, p. 6

- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3, 4 and 8).
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the TNSP has more assets to maintain leading to higher opex requirements (see attachments 6 and 7).
- the TNSP's approach to managing its network. The TNSP's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachment 6).

We have considered interrelationships, including those above, in our analysis of the constituent components of our draft decision. These considerations are explored in the relevant attachments.

6 Consultation

Stakeholder participation is important to informed decision making under the NEL and NER. It allows us to take a range of views into account when considering how a proposal or decision contributes to the NEO. Effective consultation and engagement provide confidence in our processes and are good regulatory practice. This is reflected in the consultation process set out in the NER, under which we have:

- published Powerlink's revenue proposal and supporting material
- published an issues paper identifying preliminary issues with the revenue proposal
- invited written submissions on the revenue proposal
- held a public forum on the revenue proposal
- published this draft decision.

We also sought advice from the AER's Consumer Challenge Panel (CCP) on Powerlink's revenue proposal. Both the CCP and Powerlink met with the AER Board to discuss this review.

This process builds on consultation we undertook with a broad range of stakeholders as part of the Better Regulation program. Following changes to the NER in 2012, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[62]

This gives us confidence the approaches set out in our various guidelines, which we have applied in this decision, will result in outcomes that will or are likely to contribute to the achievement of the NEO to the greatest degree. Our Better Regulation guidelines are available on our website[63] and include:

- Expenditure forecast assessment guideline
- Expenditure incentives guideline
- Rate of return guideline
- Consumer engagement guideline for network service providers
- Shared assets guideline
- Confidentiality guideline.

The guidelines provide businesses, investors and consumers predictability and transparency of our approach to regulation under the new rules.

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62 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4. 7–13.

63 www.aer.gov.au/better-regulation-reform-program

6.1 Consumer engagement

Recent changes to the NER provide further support for consumer involvement in the regulatory process, and enable us to engage more productively with energy consumers and businesses.[64] Chapter 6A of the NER was amended to, among other things, require:

- TNSPs to submit an overview with their revenue proposal which describes how they have engaged with consumers and sought to address any relevant concerns identified by that engagement[65]
- the AER to publish an issues paper after receiving the TNSP's revenue proposal.[66] The purpose of the issues paper is to assist consumer representative groups to focus on the key preliminary issues on which they should engage and comment[67]
- the AER, when determining capex and opex allowances, to have regard to the extent to which the forecast includes expenditure to address the concerns of consumers as identified by the TNSP in the course of its engagement with the consumers.[68]

Our Better Regulation Consumer engagement guideline sets out our expectations of how network businesses should engage with their customers. We expect the network businesses to demonstrate a commitment to ongoing and genuine consumer engagement on issues relevant to consumers. We want to see businesses being more accountable to their consumers.[69] We also understand the businesses may need some time to develop and implement robust and comprehensive engagement strategies and approaches.[70]

As set out in the guideline, we monitor consumer engagement activities through the CCP and our ongoing engagement with stakeholders. We may publicly comment in our decisions on any shortcomings that we identify from an expenditure proposal that reflect weaknesses in consumer engagement.[71]

We have considered the material presented in Powerlink's revenue proposal (section 6.2), and stakeholder views presented to us in submissions (section 6.4) to form a view of its progress in implementing improved engagement strategies and approaches (section 6.5). We have not undertaken a substantive review of Powerlink's

64 AEMC, *Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers),* Rule 2012.

65 NER, cl. 6A.10.1(g)(2).

66 NER, cl. 6A.11.3(b)(1).

67 AEMC, *Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers),* Rule 2012.

68 NER, cll. 6A.6.6(e)(5A) and 6A.6.7(e)(5A).

69 AER, *Better Regulation: Consumer engagement guideline for network service providers,* November 2013, p. 5.

70 AER, *Better Regulation: Consumer engagement guideline for network service providers,* November 2013, p. 12.

71 AER, *Better Regulation: Consumer engagement guideline for network service providers,* November 2013, p. 12.

consumer engagement approaches and strategies against the above best practice principles as part of this process.

6.2 Powerlink's consumer engagement activities

Powerlink submitted that it:

- engaged with stakeholders early in the process of developing its regulatory proposal to get input on its methods and processes rather than just on its outputs[72]
- hired research firm ACCSR to undertake research to better understand customer perceptions of Powerlink[73]
- established a Customer and Consumer Panel incorporating directly connected customers, consumer advocates and industry representatives[74]
- hosted a demand and energy forecasting forum in March 2015
- hosted an annual transmission network forum in July 2015
- developed a strategy to host forums on its network area plans
- undertook one-on-one briefings with key stakeholders, including Queensland Government, AEMC, Energex, Ergon Energy, Queensland Resources Council and the Energy Users Association
- undertook a transmission pricing webinar in October 2015
- established sections of its corporate website for stakeholder engagement and the revenue proposal process.

6.3 How Powerlink's stakeholder engagement influenced decision making

Powerlink submitted that one of its objectives was to genuinely consider feedback received and ensure that stakeholders have the appropriate level of influence on decisions. Powerlink noted the following impacts of its engagement program on its regulatory proposal:[75]

- Capital expenditure - use of a more detailed analysis of bottom-up information for reinvestment expenditure where there is less certainty of the ongoing need for an asset, introduced geographic zones into the repex model to reflect that different environments have a different impact on assets
- Operating expenditure - reviewed opex for efficiencies at an individual line item level, engaged independent consultant to review Powerlink's opex performance

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72 Powerlink, *2018–22 Powerlink Queensland revenue proposal*, January 2016, p. 11.

73 Powerlink, *2018–22 Powerlink Queensland revenue proposal*, January 2016, p. 13.

74 Powerlink, *2018–22 Powerlink Queensland revenue proposal*, January 2016, p. 15.

75 Powerlink, *2018–22 Powerlink Queensland revenue proposal*, January 2016, pp. 17–19.

- Demand and energy forecasting - Powerlink developed a new approach to demand and energy forecasting which assesses the impact of battery storage and energy efficiency
- Rate of return - Powerlink communicated early on potential WACC outcome to assist customers in decision making, Powerlink also undertook engagement with stakeholders to understand their views on alternative depreciation models
- Network planning - Powerlink involved customers in area plan forums to discuss cost v reliability trade-offs for the Greater Brisbane and Central Queensland to Southern Queensland areas
- Engagement approach - Powerlink provided multiple opportunities for stakeholders to interact face-to-face with Powerlink, engagement focussed on aspects of Powerlink's operations that have the greatest impact on electricity prices.

6.4 Consumer submissions

In general the submissions received regarding Powerlink's approach to its stakeholder engagement were very positive. Stakeholders spoke highly of Powerlink's openness and transparency. Stakeholders also commented that Powerlink listened to views presented through the consumer engagement process and made efforts to respond in appropriate ways. As a result, stakeholders generally felt that there were no negative surprises and that their expectations were largely met through the regulatory proposal.[76]

The CCP members did note however that there is some scope for Powerlink to improve its stakeholder engagement going forward. The CCP members submitted that, although Powerlink's stakeholder engagement approach was well considered, its execution of the program was somewhat limited. The CCP members considered that Powerlink should have considered the 'reach' of its program to gather information from a broader variety of consumers that are more reflective of the diversity of Powerlink's customer base.[77]

6.5 Our view of Powerlink's consumer engagement

Overall we consider that Powerlink has taken important steps to engage with its customers. Stakeholders have commented that Powerlink listened to their views and made efforts to respond appropriately. Stakeholders also commented that Powerlink were open and transparent and that there were no negative surprises in its regulatory proposal. This is very positive. We consider that the stakeholder engagement taken by

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[76] CCP (Jo De Silva), *Submission to the AER on Powerlink's regulatory proposal 2017–22*, 28 April 2016, pp. 10–11; CCP (Hugh Grant and David Headberry), *Submission to the AER, Powerlink Queensland 2018–22 revenue proposal,* 20 June 2016, pp. 75–78; Queensland Resources Council, *Submission on Powerlink revenue determination 2017–22*, 29 April 2016, pp. 1–2.

[77] CCP (Hugh Grant and David Headberry), *Submission to the AER, Powerlink Queensland 2018–22 revenue proposal,* June 2016, pp. 75–76.

Powerlink to date has significantly built on the engagement program undertaken in previous regulatory reviews for other network service providers.

We accept that there are some concerns from stakeholders, in particular from members of the CCP, regarding Powerlink's approach to stakeholder engagement in the lead up to the submission of its regulatory proposal. We note however that stakeholder engagement is a relatively new aspect undertaken by network service providers and should continue to improve over time.

Powerlink has also acknowledged that its approach to stakeholder engagement will continue to evolve based on feedback received from customers and consumers about recent engagement activities.[78] We expect that Powerlink will take into account the issues raised by stakeholders in developing its stakeholder engagement program going forward.

[78] Powerlink, *2018–22 Powerlink Queensland revenue proposal*, January 2016, p. 21.

A Constituent components

Our draft decision on Powerlink's transmission determination includes the following constituent components:[79]

Constituent component
In accordance with clause 6A.14.1(1)(i) of the NER, the AER does not approve the total revenue cap set out in Powerlink's building block proposal. Our draft decision on Powerlink's total revenue cap is $3720.8 million ($ nominal) for the 2017–22 regulatory control period. This decision is discussed in Attachment 1 of this draft decision.
In accordance with clause 6A.14.1(1)(ii) of the NER, the AER does not approve the maximum allowed revenue (MAR) for each regulatory year of the regulatory control period set out in Powerlink's revised building block proposal. Our decision on Powerlink's MAR for each year of the 2017–22 regulatory control period is set out in Attachment 1 of this draft decision.
In accordance with clause 6A.14.1(1)(iii) of the NER, the AER has decided to apply the service component, network capability component and market impact component of Version 5 of the service target performance incentive scheme (STPIS) to Powerlink for the 2017–22 regulatory control period. The values and parameters of the STPIS are set out in Attachment 11 of this draft decision.
In accordance with clause 6A.14.1(1)(iv) of the NER, the AER's decision on the values that are to be attributed to the parameters for the efficiency benefit sharing scheme (EBSS) that will apply to Powerlink in respect of the 2017–22 regulatory control period are set out in Attachment 9 of this draft decision.
In accordance with clause 6A.14.1(1)(v) of the NER, the AER has approved the commencement and length of the regulatory control period as Powerlink proposed in its revenue proposal. The regulatory control period will commence on 1 July 2017 and the length of this period is five years, expiring on 30 June 2022.
In accordance with clause 6A.14.1(2) and acting in accordance with clause 6A.6.7(d) of the NER, the AER has not accepted Powerlink's total forecast capital expenditure of $959.7 million ($2016–17). The reasons for this draft decision and our substitute estimate of Powerlink's total forecast capex for the 2017–22 regulatory control period is $775.2 million ($2016–17). This is discussed in Attachment 6 of this draft decision.
In accordance with clause 6A.14.1(3)(i) and acting in accordance with clause 6A.6.6(c) of the NER, the AER accepts Powerlink's total forecast operating expenditure inclusive of debt raising costs of $976.7 million ($2016–17). This is discussed in Attachment 7 of this draft decision.
In accordance with clause 6A.14.1(4)(i), the AER has determined that the following proposed projects are contingent projects for the purpose of the revenue determination: • Central to North Queensland Reinforcement • Northern Bowen Basin area • Bowen Industrial Estate • QNI upgrade (Queensland component) • Gladstone area reinforcement. This is discussed in Attachment 6 of this draft decision.
In accordance with clause 6A.14.1(4)(ii), the AER is satisfied that the capital expenditure of $325.9 million for the five contingent projects as described in Powerlink's current regulatory proposal reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors. This is discussed in Attachment 6 of this draft decision.
In accordance with clause 6A.14.1(4)(iii), the AER has determined that the triggers proposed by Powerlink for the five contingent projects are inconsistent with the NER. Our draft decision includes revised triggers to provide greater certainty as to our approach should Powerlink seek to act on these contingent projects. This is discussed in Attachment 6 of this draft

[79] NER, cl. 6A.14.

Constituent component
decision.
In accordance with clause 6A.14.1(4)(iv), the AER has determined that the following proposed contingent projects are not contingent projects: • North West Surat Basin Area • South Galilee Basin. This is discussed in Attachment 6 of this draft decision.
In accordance with clause 6A.14.1(5A) of the NER, the AER has determined that version 1 of the capital expenditure sharing scheme (CESS) as set out the Capital Expenditure Incentives Guideline will apply to Powerlink in the 2017–22 regulatory control period. This is discussed in Attachment 10 of this draft decision.
In accordance with clause 6A.14.1(5B) and 6A.6.2 of the NER, the AER has decided that the allowed rate or return for the 2017–18 regulatory year is 5.48 per cent (nominal vanilla), as set out in Attachment 3 of this draft decision. The rate of return for the remaining regulatory years 2018–22 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6A.14.1(5C) of the NER the AER has decided that the return on debt is to be estimated using a methodology referred to in clause 6A.6.2(i)(2), and using the formula to be applied in accordance with clause 6A.6.2(l). The methodology and formula are set out in Attachment 3 of this draft decision.
In accordance with clause 6A.14.1(5D) of the NER the AER has decided that the value of imputation credits as referred to in clause 6A.6.4 is 0.4. This is discussed in Attachment 4 of this draft decision.
In accordance with clause 6A.14.1(5E) of the NER the AER has decided, in accordance with clause 6A.6.1 and schedule 6A.2, that the opening regulatory asset base (RAB) as at the commencement of the 2017–22 regulatory control period, being 1 July 2017, is $7164.7 million ($ nominal). This is discussed in Attachment 2 of this draft decision.
In accordance with clause 6A.14.1(5F) of the NER the AER has decided that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of Powerlink's regulatory control period as at 1 July 2022. This is discussed in Attachment 2 of this draft decision.
In accordance with clause 6A.14.1(6) of the NER the AER has approved Powerlink's proposed negotiating framework. This is set out in Attachment 14 of this draft decision.
In accordance with clause 6A.14.1(7) of the NER the AER has specified the negotiated transmission services criteria for Powerlink. This is set out in Attachment 14 of this draft decision.
In accordance with clause 6A.14.1(8) of the NER the AER does not approve Powerlink's proposed pricing methodology. Our reasons for this draft decision on Powerlink's proposed pricing methodology is set out in Attachment 12 of this draft decision.
In accordance with clause 6A.14.1(9) of the NER the AER has approved the following nominated pass through events to apply to Powerlink for the 2017–22 regulatory control period in accordance with clause 6A.6.9: • terrorism event • insurance cap event. These events have the definitions set out in Attachment 13 of this draft decision.

B List of submissions

We received 8 submissions in response to Powerlink's revenue proposal. These are listed below.

Submission from	Date received
Aurizon	28 April 2016
Consumer Challenge Panel (Jo De Silva)	28 April 2016
Consumer Challenge Panel (Hugh Grant and David Headberry)	20 June 2016
Cotton Australia	2 May 2016
Powerlink	28 April 2016
Powerlink - submission on issues raised at public forum	28 April 2016
QRC	29 April 2016
University of Queensland (Professor Simon Bartlett)	28 April 2016