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Revenue Proposal to AER 2018-2022

Review of Forecast Non-load driven capital expenditure in Powerlink's Regulatory Proposal

Addendum Report to

Australian Energy Regulator

from

Energy Market Consulting associates

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About EMCa

Energy Market Consulting associates (EMCa) is a niche firm, established in 2002 and specialising in the policy, strategy, implementation and operation of energy markets and related network management, access and regulatory arrangements. EMCa combines senior energy economic and regulatory management consulting experience with the experience of senior managers with engineering/technical backgrounds in the electricity and gas sectors.

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Executive Summary

Purpose of this report

1. The purpose of this report is to provide the Australian Energy Regulator (AER) with technical advice to assist the AER with determining a reasonable allowance for Powerlink's non-load driven capital expenditure, the main component of which is replacement/refurbishment capital expenditure (repex, which Powerlink refers to as reinvestment expenditure). This report should be read as an Addendum to our report of July 2016, in which we concluded that there are systemic biases that are likely to have led Powerlink to over-forecast its non-load driven capital expenditure requirements for the 2018-2022 RCP[1].

2. Our assessment is based on a limited scope review of certain aspects of Powerlink's expenditure forecast.[2] It does not take into account all factors or all reasonable methods for determining a capital expenditure allowance in accordance with the National Electricity Rules (NER).

Scope of work

3. In the context of the NER capital expenditure criteria, objectives and factors, and our July 2016 report to the AER, the AER sought particular advice regarding the prudency and efficiency of a sample of 18 of Powerlink's non-load driven projects and the implications for Powerlink's proposed expenditure allowance. The projects have been completed or initiated within the 2011-2015 period.

4. Powerlink advises it has calibrated its repex model using asset age profiles derived from historical replacement quantities.[3] The review of the sample of historical projects is designed to assist with assessing whether the inputs to Powerlink's repex model reflect

[1] EMCa, *Review of Forecast Non-load driven capital expenditure in Powerlink's Regulatory Proposal.* Report to AER (July 2016)

[2] The scope of our review considers specific capex projects and programs for non-load driven capital expenditure as agreed with the AER and limited review of Powerlink's top-down 'repex' model outputs in developing its forecast of expenditure requirements. This expenditure is a subset of the capital expenditure within Powerlink's Revenue Proposal.

[3] As described in Powerlink's, Appendix 5.05, *Non-Load Driven Network Capital Expenditure Forecasting Methodology,* 2016

prudent and efficient expenditures. This in turn, will assist the AER to: (i) assess the prudency and efficiency of the outputs of Powerlink's repex model, and (ii) decide upon an adjustment (if any) to Powerlink's proposed non-growth driven expenditure.

5. We are required in this Addendum Report to recommend an adjustment to Powerlink's proposed repex expenditure by supplementing our initial findings with a quantitative assessment based on our review of the further 18 projects.

Approach

6. In accordance with the scope of work defined by the AER, in undertaking our assessment of the prudency and efficiency of Powerlink's 2010/11-2014/15 replacement/refurbishment expenditure,[4] we took into account the following aspects in our review of the 18 projects:

- The need for the investment;
- The options to address the need; and
- The scope of work and the timing.

Findings from the Project Reviews

Need for the investment

7. From our review of the documentation provided for the sample of 18 projects non-load driven projects, we consider that there is a bias in Powerlink's repex modelling, to under-estimating the remaining life of the assets in question and thereby over-estimating the required expenditure. We found that:

- There was an absence of evidence to support claims regarding increasing numbers and impacts of defects and threats to reliability; and
- The evidence presented in the Condition Assessment Reports did not in all cases support the condition 'score' (where one of the two scoring approaches was used) nor the assessed remaining life.

Options to address the need

8. In general, for the projects considered, Powerlink has not provided robust options analyses:

- In many cases it did not consider an adequate range of options, including life extension options, to address the major risks, at a lower cost;
- Powerlink did not appear to use a formal risk assessment process; and
- Whilst Powerlink used NPV analysis as a tool to select its preferred option from those considered, it did not undertake quantitative cost-risk trade-off analyses to demonstrate that the scope, timing and cost of the selected option is prudent and efficient.

Powerlink's scope of work

9. In several cases the scope of work defined by Powerlink included upgrades that were load-driven or replacements that were not driven by asset condition or obsolescence and are therefore not suitable for application to the repex model. Powerlink advises that it removed quantity data for its repex modelling where the project was not primarily driven by the

[4] For which the primary driver was condition (or obsolescence) rather than safety reasons or other compliance-related issues and by which we refer to activities classified as capital expenditure

condition of the structures.[5] However, the timing and scope of work in several projects appears to have been influenced by load and/or generator-driven forecasts, with opportunities for extending the life of assets foregone because of the forecast need to upgrade capacity and/or fault levels in the short-term.

10. Furthermore, in a number of projects, Powerlink bundled the replacement of assets that were in relatively good condition with replacement of assets that were in poor condition. Based on our understanding of Powerlink's assessment of historical replacement quantities, we understand that it took into account the replacement of these younger assets, which would have the effect of reducing the average replacement age of the assets and, in turn, the replacement lives used in Powerlink's repex model.

11. We consider that if Powerlink had adopted an asset management strategy directed to economic life extension, the replacement lives would be considerably longer than it has used in its repex model.

12. Even given the foregone opportunities to refurbish elements rather than replace them or to replace a smaller sub-set of assets to address major condition-related issues rather than large scale replacement in some cases, the actual replacement lives of the assets replaced are, on average, significantly longer than the replacement lives assumed in Powerlink's repex model.[6]

Changes to Powerlink's asset management strategies and practices

13. Whilst Powerlink advises that it had not materially changed its asset management strategies over the 10-year period from 2005-2015, it is apparent from the projects reviewed that Powerlink considered a broader range of options, including life extension options such as 'partial refits', in more recent projects.

Implications of the findings for the repex model

Systemic issues leading to over-estimation

14. We consider that the systemic issues identified in this review support the biases that we identified in our initial Technical Report and that in aggregate the biases lead to an over-estimate of forecast expenditure.

15. We consider that Powerlink's repex model is likely to be based on replacement lives that are, for the asset classes considered, too short, because:

- The link in condition assessment reports between the assets assessed to be in poor condition and the assessed survival life of the entire asset population appears to be conservative;
- Powerlink's business cases did not adequately demonstrate that the scope and timing of the replacement work is prudent and efficient;
- In almost all of the projects considered, the actual replacement lives of the assets that were replaced due to condition and/or obsolescence issues were significantly greater than Powerlink's assumed replacement lives in its repex modelling;

[5] Appendix 5.05, section 2.4

[6] Noting that transformer replacement projects are not included in the repex model

- Powerlink's selected replacement approach often involved 'bundling' assets that did not require replacement on the basis of condition and/or obsolescence with assets that did require replacement.

Assessment of prudent and efficient level of expenditure

16. We consider that the replacement lives used as inputs to Powerlink's repex model should be extended for the following asset categories:
    - transmission towers[7],
    - secondary systems, and
    - substation/switchbay equipment (i.e. primary equipment).

17. We recommend that the AER considers an adjustment to Powerlink's repex expenditure forecast for the 2018-2022 period based on extending the replacement lives for the following categories by the one standard deviation presented in Table 9 of Powerlink's Non-Load Driven Network Capital Expenditure Forecasting Methodology document:
    - Transmission towers (all corrosion zones);
    - Substation switchbay equipment; and
    - Secondary systems bay and non-bay (excluding metering).

18. We do not consider that any further adjustment on the basis of Powerlink's proposed repex for power transformers is warranted.

19. The life extensions above will reduce the expenditure requirements indicated by Powerlink's repex model. However, as a partial offset to this reduction, we recommend that the AER allows for a prudent increase in Powerlink's preventative and corrective replacement expenditure on asset life extension, including earlier painting of transmission towers. We propose that an allowance of 15% of the initial repex forecast should be provided to support this increased activity.

[7] With different increases for towers in the three different corrosion zones

1 Introduction

1.1 Purpose of this report

20. The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (NER), is required to conduct an assessment of the revenue of prescribed transmission services provided by Powerlink for the 2018-2022 regulatory control period (RCP).

21. Powerlink provided its Revenue Proposal for the 2018-2022 RCP to the AER in January 2016. The AER engaged EMCa as a Technical Consultant to review and provide advice on the prudency and efficiency of the non-load driven capital expenditure proposed in Powerlink's Revenue Proposal. We submitted a report titled *Review of Forecast Non-load driven capital expenditure in Powerlink's Regulatory Proposal* (our initial report) to the AER in response to the particular scope of work defined by the AER.

22. The purpose of this report is to provide the AER with supplementary information pertaining to our findings from reviewing a sample of 18 replacement/refurbishment capital projects that were completed or initiated in the period 2010-2015, in order to assist the AER with determining a reasonable allowance for Powerlink's non-load driven capital expenditure.

1.2 Scope of requested work

23. In our initial report on Powerlink's non-load driven expenditure forecast, we found that there were systemic biases that we considered were likely to have led to over-estimation of Powerlink's non-load driven capital expenditure requirement for the 2018-2022 RCP.

24. Our review of Powerlink's governance and management found a bias for over-estimation of risk for non-load driven capex, particularly that Powerlink's use of risk-based analysis and prioritization is immature and not yet fully utilized across the business. EMCa concluded that Powerlink's forecasting methods show an over-forecasting and over-estimating bias.

25. We further noted that Powerlink's use of the AER's repex model, whilst based on sound principles, is reliant on the validity of a large set of inputs, verification of which was outside

the scope of our initial technical advice. In reviewing a sample of Powerlink's approved and proposed repex projects for the next period, we found evidence of risk and forecasting biases which we considered systemic in nature.

26. In the context of the NER capital expenditure criteria, objectives and factors, the AER sought particular advice regarding the prudency and efficiency of a sample of 18 of Powerlink's non-load driven projects as listed in Appendix A and, from this, evidence for certain assumptions Powerlink has used in its repex modelling. Powerlink advises that only a sub-set of the 18 projects directly influenced the assessment of the median replacement lives and forecast replacement/refurbishment expenditure from its repex model. We understand that our review of the 18 projects provided is intended to assist the AER: (i) assess the validity of Powerlink's inputs to Powerlink's repex model; and (ii) decide upon an adjustment (if any) to the proposed expenditure.

27. The AER has requested advice in an Addendum Report to our initial report that quantifies what we consider to be the over-estimation in Powerlink's capex forecasts and provides supporting reasons and evidence. In particular, the AER sought advice on the extent of any overestimation in relation to:

- Lines;
- Transformers;
- Primary substation equipment; and
- Secondary substation equipment.

1.3 Approach

28. The AER provided Powerlink's project documentation for each of the 18 projects to provide the basis for EMCa's assessment. The documentation typically comprised of:

- Business Case and other approval paperwork;[8]
- Condition Assessment Report;
- Project Proposal Report; and
- Project Scope Report.

29. A summary of the projects provided for review is included in Appendix A.

30. In undertaking the assessment of the prudency and efficiency of Powerlink's replacement expenditure approved by its Board we took into account the following aspects:

- *The need for the investment* – we considered whether Powerlink had reasonably demonstrated the need for the investment;
- *The options to address the need* – we considered whether Powerlink had identified and assessed a reasonable range of options to address the identified need and whether the efficient option had been chosen; and

[8] Such as Memoranda to the Board seeking approval for the approach, timing and cost recommended in the respective Business Case

- *The scope of work and timing* – based on the identified need, we considered whether there were likely to be alternative options that varied the scope and timing of work to address the identified business need, and the robustness of Powerlink's cost-risk analysis (i.e. comparative analysis of options, and of the selected option).

31. In addition to the aspects described above, we also sought to identify:

- *Material changes in Powerlink's asset management strategies and practices over time* – this is relevant to Powerlink's forecast repex requirement for the 2018-2022 RCP because the majority of its expenditure is derived from its repex model which in turn is based on historical expenditure and asset survival lives. In assessing the relevance of these impacts we were mindful of the engineering adjustments and calibrations that Powerlink has advised it made to its repex model to more accurately reflect its future expenditure requirements;
- *Comparison of Powerlink's practices to good industry practice* – some of Powerlink's projects that form the basis of its repex model were approved five or more years ago, responding to asset-related issues that were identified even earlier. Whilst Powerlink's asset management strategies and practices may have changed over time, the decisions affecting the programs on which Powerlink has calibrated its repex model may not be commensurate with Powerlink's current and prospective practices. If so there is likely to be further improvement in managing life-cycle costs that are not reflected in historical expenditure; and
- *Characteristics of Powerlink's assets* – in particular the average age of the assets in the key categories subject to this review. This contributes to our assessment of the likely impact of any adjustment to Powerlink's proposed repex that we recommend.

1.4 Structure of this report

32. The structure of this report is, to the extent possible, aligned with the structure of the AER Scope of Work and the review approach described above.

Section	Title	Content
1	Introduction	This section sets out the purpose and scope of our review
2	Background	This section provides a summary of the sample of 18 projects (listed in Appendix A)
3	Assessment of transmission lines projects	This section provides our assessment of the prudency and efficiency of the sample transmission line replacement projects
4	Assessment of transformer projects	This section provides our assessment of the prudency and efficiency of the sample transformer replacement projects
5	Assessment of primary substation equipment projects	This section provides our assessment of the prudency and efficiency of the sample

Section	Title	Content
		primary substation equipment replacement projects
6	Assessment of secondary substation equipment projects	This section provides our assessment of the prudency and efficiency of the sample secondary substation equipment replacement projects
7	Implications for proposed repex	This section provides a summary of the findings from the project assessments, a recommended adjustment to Powerlink's repex expenditure forecast and the rationale for our recommended adjustment

1.5 Information sources

33. We have examined relevant documents provided by Powerlink in support of the projects that the AER has designated for review. Powerlink provided further documents in response to our information requests. These documents are referenced directly where they are relevant to our findings.

1.6 Rounding of numbers and real conversion

34. Numerical totals in tables may not present as being equivalent to the sum of the individual numbers due to the effects of rounding. This Report refers to costs in nominal dollars (as reported in Powerlink's documentation) unless denoted otherwise.

2 Background

2.1 Introduction

35. In our initial Report to the AER on Powerlink's non-load driven capex forecast for the 2018-2022 RCP, we observed systemic biases that we consider likely to have led Powerlink to over-forecast its non-load driven capital expenditure requirements for the 2018-2022 RCP.

36. As Powerlink has chosen to rely on its predictive model (which it adapted from the AER's repex model) for determining 89% of its non-load driven expenditure forecast and the inputs to the predictive model are derived primarily from historical information[9], the quality of the input data is a critical factor in the quality of the outputs.

37. In our initial report, we identified issues with Powerlink's governance and management and with its forecasting methods that in aggregate suggested that, even with Powerlink's input adjustments,[10] its historical replacement quantities and cost may not have been prudent and efficient. This in turn, raised questions regarding whether the outputs from Powerlink's repex model were likely to be representative of the prudent and efficient level of expenditure required for the next RCP.

38. The AER selected the sample of 18 projects for review and obtained supporting documentation from Powerlink to provide a basis for assessing the prudency and efficiency of historical replacement quantities.

2.2 Overview of non-load driven projects

39. Table 1 summarises the number of projects and average cost of the projects in each of the four key asset categories. It is important to note that Powerlink addresses more than one key asset category in a single project for asset categories other than transmission line projects – for example whilst the primary need being addressed is transformer condition, in

[9] Five year period from 30 June 2010 to 30 June 2015

[10] As described Appendix 5.05

addition to replacing the transformer, other primary plant is also replaced within the project scope. The total costs in the table are derived from the amounts approved (including contingency) in the Business cases for the respective projects.

Table 1: Sample projects ($m, nominal)

Asset category [1]	# of projects	Total cost	Average cost
Transmission line	4	$ 257.15	$64.3
Transformer	2	$ 30.20	$15.1
Substation primary equipment	7	$ 304.65	$43.5
Substation secondary equipment	5	$ 91.90	$18.4
Total	**18**	**$ 683.90**	**$141.3**

[1] based on the primary driver noting that most of the non-lines projects include replacement of other assets

Source: EMCa analysis of Powerlink project documentation

3 Assessment of transmission lines projects

3.1 Introduction

41. Four transmission line replacement projects were provided for assessment. The projects are shown in Table 2.

42. Each of the transmission line sections addressed were in coastal areas (corrosion zone DEF). The actual average replacement life of the lines is 12 years longer than the assumed 40.3-year replacement life Powerlink has used in its repex model. The approved project costs include contingency allowances of 10% in each case.

Table 2: Transmission line projects provided for review ($m, nominal)

Project name	Business case approval	Project completion date	Age of line at completion	Actual life less repex model life*	Approved cost	Final cost	Cost difference
Collinsville-Proserpine coastal section replacement	2013	2014	47	7	$ 18.80	$ 13.50	$ (5.30)
Cardwell-Ingham 132kV line replacement	2010	2013	55	15	$ 66.30	$ 67.30	$ 1.00
Tully-Cardwell 132kV line replacement	2010	2014	56	16	$ 63.00	$ 70.25	$ 7.25
Ingham/Yabulu Sth 275/132kV line replacement	2008	2011	53	13	$ 107.00	$ 101.80	$ (5.20)
Totals					$ 255.10	$ 252.85	$ (2.25)

* 40.3 years, based on corrozion zone DEF, source: Powerlink, *Response to EMCa Information Request, PQ0142* , 3 June 2016

Source: EMCa analysis of project documentation provided by Powerlink via AER

3.2 Project assessment

3.2.1 Collinsville-Proserpine 132kV line

The need for the investment

43. The Collinsville-Proserpine line was built in 1967. The condition assessment of the Mackay to Proserpine line (of which the Collinsville-Proserpine is a section) was undertaken by Powerlink in 2010. The Condition Assessment Report (CAR) concluded that the 16km coastal section had reached the end of its 50-year design life, based on:

- All galvanised tower members, nuts, bolts and hardware components were exhibiting evidence of Grade 2 corrosion[11]; and
- The coastal sections on the western side of Lake Proserpine (Built Sections 1203 and 1240), had corroded at a more advanced rate than other sections.

44. Powerlink also considered that in the event of structural or conductor failure, cascade failure to adjacent towers could occur which would result in extended outages in the Proserpine area.

45. The Business Case further reported that more recent (uncited) site inspections had identified some structures with Grade 4 corrosion.

Options analysis and scope of work

46. Powerlink identified four options to address the identified issues:

- Option 1: line refurbishment followed by adjacent replacement in 2017;
- Option 2: line refit excluding painting followed by adjacent replacement in 2024;
- Option 3: line refit including painting by 2014; and
- Option 4: in-situ replacement by 2014.

47. Powerlink's Board approved Option 4 based on comparative NPV analysis[12] and 'strategic fit' with the long term requirements for the Proserpine area. Option 4 involved demolishing 16km of the double circuit 132kV coastal section of the line and rebuilding it with 43 structures, uprated conductor (replacing the existing 84 MVA Tiger conductor with 129MVA Neon conductor) and 48 fibre OPGW. Option 3 was estimated by Powerlink to extend the line life by 25 years at a cost $3m (capex) less than Option 4.

EMCa observations

48. The 2010 CAR indicates that at 43 years old, the 16km coastal line section had '*reached the end of its 50 year design life*' because '*all galvanised tower members, nuts, bolts and hardware components…are exhibiting extensive amounts of grade 2 corrosion, with minor metal loss in some instances'*.[13] The CAR does not recommend a replacement timeframe.

[11] '*Grade 2 - indicates surface rust with loss of galvanic protective layer in some areas; Grade 3 indicates significant surface rust, some pitting of steel, loss of galvanic protective layer and small steel loss; and Grade 4 - indicates large steel loss and loss of strength',* Powerlink, Business Case, *Project CP.1942 Collinsville Proserpine Coastal Section Replacement,* July 2013

[12] Options 2, 3, and 4 NPV results were similar

[13] CAR, page 4

49. Grade 2 corrosion is the second lowest level of Powerlink's four-grade scale for corrosion.

50. It is unclear from the information provided for option 1 why addressing the most serious defects on the line would only extend the life of the line by 3 years. Given the relatively low grade of corrosion and addressing the unspecified 'grade 4 conditions' (referred to in the Business Case) could reasonably be expected to result in a longer deferment of line replacement and a lower total net present cost (NPC). Risk assessment in accordance with good industry practice is not included in Powerlink's analysis. There is limited risk-cost trade-off assessment of option 4 to confirm the timing of the replacement is economically efficient. In summary, there is insufficient information to confirm that replacement of the line in 2014 was prudent and efficient.

51. The line was replaced at 47 years old, which is relatively young for a well-maintained power line, although the tower is in coastal environment. The replacement age in this case exceeds Powerlink's replacement life used in its repex model by 7 years (+17%). Based on the information provided, the project could reasonably be expected to have been deferred for a longer period at a lower overall PV cost by adopting Option 1 rather than Option 4. The cost of the replacement line was \$0.84 million/km, which is almost 30% less than forecast. The line was constructed with 48 fibre OPGW without justification and, more significantly, the project included conductor size uprated by approximately 50%.

3.2.2 Cardwell-Ingham 132kV line replacement

The need for the investment

52. The Cardwell-Ingham double circuit 132kV transmission line was built in 1958 and is 46km long. The condition assessment of the line was undertaken by Powerlink in 2008 when the line was 50 years old. It concluded that the steel lattice towers had 5-8 years remaining life because of grade 3-4 corrosion, the steel grillage foundations were also at corrosion level 3-4 with a remaining life of 2-5 years, and line components were assessed as requiring replacement within 3-5 years. The Project Scope Report adds that the inaccessible and remote terrain made it '*difficult and costly to maintain, and the risk of serious supply disruption to supply security increases with the years*'.[14]

Options analysis and scope of work

53. Powerlink did not present any options in its Business Case. Instead, it referred to the replacement strategy for the Far North Queensland 132kV coastal transmission lines strategy approved by the Powerlink Board in 2004.[15] The Business Case states that '*the strategy selected is the least cost solution to maintaining supply to the coastal areas north of Townsville over a 20 year period*.' In its Business Case, Powerlink state that the assumptions used in the analysis which supported the strategy had been reviewed and no changes that would affect the outcome of the original analysis were identified.

54. The project involved replacing the existing 132kV double circuit line by 2012[16] with a double circuit 275/132kV line, initially operated at 132kV and included a dual fibre dual OPGW. Based on information in the CAR, the original 132kV circuits were rated at 84MVA (i.e. 168MVA total). The new 132kV conductor rating is 200MVA and the 275kV rating is

[14] PSR, page 3

[15] A Board memorandum, dated 22 June 2004, was provided by Powerlink in response to an information request for a copy of the strategy document by EMCa

[16] The project was completed in 2013

800MVA. If operated at 275/132kV, the new transmission line will have a thermal rating of 1000MVA, six times higher than the line it replaced.

EMCa observations

55. The 2008 CAR indicates that at 50 years old, the 46km coastal line section will reach the end of its life between 2010 and 2016 due to grade 3-4 corrosion. A run-to-failure asset management strategy appears to have been followed. We did not find evidence of Powerlink undertaking anything more than basic inspection and maintenance on the line, possibly because of its view that maintenance was 'difficult and costly'.

56. The reported severe corrosion to key elements of the towers (including the footings) indicates that remedial action is likely to have been required within the nominated timeframes.

57. No options analysis is presented in the Business Case. Analysis of alternatives to replacing the line, or for deferring replacement should have been presented for completeness. Risk assessment in accordance with good industry practice is not included in Powerlink's analysis. There is limited risk-cost assessment to confirm the optimal timing of the replacement. The replacement strategy covered in the Far North Queensland strategy does not address alternatives to replacement and replacement timing.

58. We note that if the condition assessment had been undertaken at least 10 years earlier, selective replacement/refurbishment of the line may have economically extended the life of the line beyond the 55 years at which it was actually replaced.

59. The project also includes a significant capacity upgrade which has not been adequately justified and regardless should not be taken into account by Powerlink in deriving inputs to its repex model. Powerlink advises[17] that it has removed demand-related expenditure from the projects used to generate cost and timing inputs to its repex model.

60. There is insufficient detail in that document to assess the economic merits of the addition of 48 fibre OPGW earth wire, which provides additional communications capacity at an additional cost.

61. The line was replaced when it was 55 years old. The replacement age in this case exceeds Powerlink's assumed survival life for towers in corrosion zone DEF used in its repex model by 15 years (+36%). The cost of the replacement line was $1.5 million/km, which was within 2% of the forecast. The line was constructed with an additional 48 fibre OPGW without justification.

3.2.3 Tully-Cardwell 132kV line replacement

The need for the investment

62. The Tully-Cardwell double circuit 132kV transmission line was built in 1958 and is 46km long. The condition assessment of the line was undertaken by SKM for Powerlink in 2008 when the line was 50 years old. In the CAR, SKM concluded that it was beyond cost-effective repair and 'marginally fit for service.' Tower deterioration, especially of the

[17] As described in section 2, Appendix, 5.05, Non-load driven network capital expenditure forecasting methodology

foundations was the ruling criteria in determining end of life. The conductor and earthwire were in good condition.

63. SKM could find no evidence of corrective maintenance being undertaken as recommended in a 2003 Powerlink report, nor of implementation of a 'special maintenance strategy' that was supposed to be implemented through to 2008/09.

Options analysis and scope of work

64. Powerlink did not present any options in its Business Case. The Business Case refers to the Far North Queensland strategy.

65. The project involved replacing the 48 km existing 132kV double circuit line by 2012[18] with a double circuit 275/132kV, initially operated at 132kV and with 48 fibre OPGW. Based on information in the CAR, the original 132kV circuits were rated at 84MVA (i.e. 168MVA total). The new 132kV conductor rating is 200MVA and the 275kV rating is 800MVA. If operated at 275/132kV, the new transmission line will have a thermal rating of 1000MVA, six times higher than the line it replaced.

EMCa observations

66. The 2008 CAR states that at 50 years old, the 48km coastal line section has reached the end of its operational life. Whilst it is arguable that the line need not have reached the reported poor condition (i.e. through application of an alternative asset management strategy), the need to take action in the near future seems a reasonable conclusion based on the information provided.

67. No options analysis is presented. The same comments made in relation to the Cardwell-Ingham line apply in this case.

68. The line was replaced when it was 56 years old. The replacement age in this case exceeds Powerlink's assumed survival life used in its repex model by 16 years (+39%). The cost of the replacement line was $1.5 million/km, which is 12% above the forecast. The line was constructed with 48 fibre OPGW without justification and the thermal rating was uprated without sufficient justification.

69. Powerlink advises that it has removed load-related expenditure from the projects used to generate cost and timing inputs to its repex model. If done accurately, this is an appropriate step to reflect non-load driven expenditure.

3.2.4 Ingham/Yabulu South 275/132kV line replacement

The need for the investment

70. The Ingham/Yabulu double circuit 132kV transmission line was built in 1958 and is 88km long. We infer that the condition assessment report was completed by Powerlink in 2008.[19] In the CAR, SKM concluded that: '*Most components on the Townsville GT to Ingham 132kV transmission line have reached the end of their service life.'* The corrosion grades

[18] The project was completed in 2013

[19] Powerlink has provided version 1.0 of the CAR that was modified in 2016, but with no version history. As the Executive Summary refers to the line being 50 years old, we assume the CAR was originally written in 2008

are identified as 3-4 for the tower structure and tower footings with remaining life estimates of 5-10 years and 2-5 years respectively.

Options analysis and scope of work

71. Powerlink did not present any options in its Business Case. The Business Case refers to the Far North Queensland strategy.

72. The project involved replacing 48 km section of the 88km 132kV double circuit line by 2010[20] with a double circuit 275/132kV, initially operated at 132kV and with 48 fibre OPGW. Based on information in the CAR, the original 132kV circuits were rated at 84MVA (i.e. 168MVA total). The new 132kV conductor rating is 200MVA and the 275kV rating is 800MVA. If the remaining 40km of the line is rebuilt to the same specification and is operated at 275/132kV, the new transmission line will have a thermal rating of 1000MVA compared to the existing line's 168MVA, six times higher than the line it replaced.

EMCa observations

73. The 2008 CAR states that at 50 years old, the 48km coastal line section has reached the end of its operational life.

74. No options analysis was presented in the Business Case. The same comments made in relation to the Cardwell-Ingham line apply in this case.

75. The line was replaced when it was 53 years old. The replacement age in this case exceeds Powerlink's assumed survival life used in its repex model by 13 years (+32%). The cost of the replacement line was $1.2 million/km, which is 5% less than forecast. The line was constructed with a 48 fibre OPGW and uprated to a significantly higher thermal capacity without justification.

3.3 Summary

76. Our assessment of the sample of four transmission line replacement projects indicates that the volume and cost of work incurred is likely not representative of a prudent and efficient level of expenditure, for the following reasons:

- Powerlink's Condition Assessment Reports typically provide sufficient information to conclude that some form of corrective action is requested to address condition-related defects, but on balance do not provide sufficient evidence for the need to replace all the towers;
- In each of the four transmission line CARs reviewed, it would appear that an asset management strategy of replacement rather than life extension has been adopted by Powerlink. This appears to be reinforced by the apparent long term strategy of replacing and augmenting the lines as reported in the Far North Queensland strategy document;
- Powerlink has not provided compelling options analyses for any of the four projects. The options analysis in the Far North Queensland lines strategy document nominate timing for replacing the transmission lines on the basis of condition, but it does not provide option analyses for life extension. The documents provided do not demonstrate

[20] Completed in 2011

the use of a formal risk assessment process, nor does Powerlink appear to undertake adequate quantitative cost-risk trade-off analyses to demonstrate that the selected option is prudent and efficient.[21] We consider that life extension strategies should have been thoroughly considered, notwithstanding the reported defects;

- Powerlink has in our opinion not provided compelling information to demonstrate that it has selected the prudent and efficient option in each case;
- The actual replacement lives of the four transmission lives are on average 12 years longer (+31%) than the average 40.3 years assumed in Powerlink's repex model for lines in coastal areas. (i.e. Corrosion zone DEF). Furthermore, it is reasonable to assume that if Powerlink had adopted an asset management strategy directed to economic life extension (e.g. bringing forward tower re-painting) the replacement lives would be longer still[22]; and
- The actual costs of the projects included load-driven capacity upgrades and unjustified upgrades to communications capability via dual 48 fibre OPGW. Powerlink advises that it has used actual costs in its repex model after deducting a 9% allowance for the non-condition-driven expenditure from the inputs to its repex model.[23] While a deduction for this purpose is an appropriate step, from the information provided we are unable to verify whether the amount is appropriate nor were we able to verify how the deduction had been applied.

77. In summary, we consider our assessment of these projects provides supporting evidence that Powerlink's historical expenditure on its transmission line replacement was higher than would have been required under a prudent and efficient management strategy. Notwithstanding adjustments Powerlink advises it has made to its repex model, the inputs it has used are conservatively biased towards shorter asset replacement lives than Powerlink has actually obtained from its assets, therefore leading Powerlink to propose higher levels of expenditure than are prudently required in the next RCP.

[21] For example, Ausgrid is progressively developing such a tool that is based on monetising risk and determining the point in time at which the cost of risk exceeds the cost of the proposed solution

[22] Transpower New Zealand has adopted an 'early' tower painting program in which it repaints towers before signs of what Powerlink would call grade 2 corrosion occurring. Transpower has demonstrated that this is a lower cost asset management strategy than line replacement. Based on Transpower's reported criteria for tower painting and the average cost per tower, we estimate that Powerlink would need to spend the equivalent of 15% of its forecast tower replacement/refurbishment expenditure if it was to adopt an early tower painting program

[23] Powerlink's response PQ0178 (5 August 2016) to an EMCa information request

4 Assessment of transformer projects

4.1 Introduction

78. Two transformer replacement projects were provided for assessment. Powerlink has excluded transformer replacement projects from its repex model. The projects are shown in Table 3.

79. The average replacement life of the transformers in the two sample projects will be 40.5 years. The Mudgeeraba project involved replacement of transformer no 2 only. The Nebo project included primary plant replacement and it is not possible to discern the transformer replacement cost from the information provided. The approved project costs include contingency allowances of 10% in each case.

Table 3: Transformer projects provided for review ($m, nominal)

Project name	Business case approval	Project completion date	Age when replaced	Approved cost	Final cost	Cost difference
Mudgeerabra 275/100kV No 2 and 3 transformer replacement	2015	2017	42	$ 9.70	n/a	n/a
Nebo 275kV/132kV No2 transformer replacement	2012	2016	39	$ 20.50	$ 16.50	$ (4.00)
Totals				$ 30.20		

Source: EMCa analysis of Powerlink project documentation provided by AER
Notes: The Mudgeeraba project only involved replacement of transformer #2; the Nebo project involved replacement of primary plant in addition to the replacement of the no2 transformer

4.2 Project assessment

4.2.1 Mudgeeraba 275/110kV No 2 and 3 transformer replacement

The need for the investment

80. The Mudgeeraba transformers No 2 and No 3 were installed in 1974. The CAR was written in 2012 and concluded that they had both reached the end of their serviceable life based on: (i) deterioration of the paper insulation; (ii) contaminated oil; (iii) leaking tap changer; (iv) winding clamping fault withstand capacity; and (v) bushing DLA results. The Powerlink Health Index for the two transformers was reported to be 5, equating to a probability of failure of 2%. The Replacement Index was 7 for both transformers. Powerlink recommended replacement of transformer No 2 by 2017 and transformer No3 by 2019. The No 3 transformer was subsequently retired.

Options analysis and scope of work

81. Powerlink considered two options for replacing transformer No 2:

- Option 1: Replacement with a 275/110kV 250MVA transformer using a replacement 250MVA transformer on upgraded foundations (to accommodate the system spare rated at 375kV); and
- Option 2: Replacement with a 275/110kV 375MVA transformer.

82. Option 1 was selected because the additional capacity afforded by the larger transformer was considered not to be required to meet forecast demand. The transformer is scheduled to be replaced in 2017 in a vacant bay at a cost of $9.7 million.[24]

EMCa observations

83. The 2012 CAR is based on standard transformer condition assessment techniques. The assessment demonstrates a material probability of failure if corrective action is not undertaken in the short term.

84. Powerlink provides two options and selected the least cost, technically viable approach. Risk assessment in accordance with good industry practice is not included in Powerlink's analysis. There is limited risk-cost trade-off assessment to confirm the optimal timing of the replacement. Nonetheless, the transformer is scheduled to be replaced at the upper end of the range recommended in the CAR.

85. The scope and cost of the work appears to be reasonable.[25]

[24] The scope of work included extending the switchyard and associated work to connect the new transformer; spare parts from the decommissioned transformer are to be retained as spares

[25] Based on comparison of the unit costs in Appendix 7.04 with Powerlink's estimate breakdown in the Project Proposal Report and considering Powerlink's Expenditure Forecasting Methodology (Appendix 5.02)

4.2.2 Nebo 275/132kV No 2 transformer replacement

The need for the investment

86. The Nebo 275/132kV 200MVA transformers T1 and T2 were installed in 1977. The CAR was written in 2008, when the transformers were 31 years old. The CAR concluded that both transformers had reached the end of their serviceable life based on: (i) DGA analysis; (ii) Furan analysis; and (iii) the general external condition of the transformers (leaks, etc). The CAR does not include the DGA and DP recordings, so it is not possible to confirm that the transformer requires replacement in the nominated timeframe.[26] The CAR recommended replacement within 3-7 years.

Options analysis and scope of work

87. Powerlink considered two options for replacing T2:
- Option 1: Replacement with a 275/132kV 375MVA transformer in-situ.
- Option 2: Replacement with a 275/132kV 375MVA transformer at a new location.

88. Both options included replacement of selected 132kV primary plant associated with feeder bays and bus section bays. Option 1 was selected and the transformer was scheduled to be replaced in 2014 in a vacant bay at a cost of $20.5 million.

EMCa observations

89. The 2012 CAR is based on standard transformer condition assessment techniques but it is not possible to discern from the information provided in the CAR whether the recommended replacement age is reasonable. The external condition of the transformer evident from the CAR is indicative of a lack of adequate maintenance.

90. Powerlink provides two options only and has selected the least cost technically viable approach. Risk assessment in accordance with good industry practice is not included in Powerlink's analysis. There is limited risk-cost assessment to confirm the optimal timing of the replacement. Nonetheless, the transformer is scheduled to be replaced at the upper end of the range recommended in the CAR.

91. The scope of work includes an upgrade of the transformer according to Powerlink's standardisation approach. The additional cost in replacing the feeder and bus section bays is required to provide sufficient circuit rating to match the transformer capacity. There is no justification provided for this and therefore no justification for the additional cost.

4.3 Summary

92. Powerlink has not included transformer replacement projects in its repex model. It has instead determined its transformer replacement requirements and expenditure from a 'bottom-up' perspective.

93. The purpose of reviewing the transformer projects was to assist with the assessment of the quality of Powerlink's approach to determining (and justifying) the level of expenditure required.

[26] For example, a Furan (2-furaldehyde) content >10 ppm typically indicates that the transformer is at its end-of-life

94. We found evidence that Powerlink's approach to justifying these two transformer projects exhibits similar systemic issues that we found in our initial review and that are exhibited in projects driven by asset-related issues in other asset categories, including:

- Inadequate options analysis to demonstrate that the prudent and efficient path has been selected; and
- Evidence that asset management strategies applied in the past have led to premature replacement of the assets, noting that load-driven limitations may also have contributed to the timing decisions.

95. However, based on the condition assessment information provided, we consider that the state of the transformers was such that replacement by the recommended dates was likely to be prudent. In light of this additional information, on balance the reported condition of the transformers is such that the replacement expenditure that Powerlink has proposed for the next RCP is reasonably likely to be required.

5 Assessment of primary substation equipment projects

5.1 Introduction

97. Six projects were provided for assessment that were predominantly primary plant replacement projects. The Blackwater, Nebo, and Callide A projects were not included in calibrating Powerlink's repex model. The projects are shown in Table 4.

98. The average replacement life of the primary plant was 44 years. Two projects involve secondary systems replacement and the information provided makes it difficult to separately discern the primary plant replacement cost, so the total project cost has been provided. Three of the projects are not yet completed, so a final cost is not available. The approved project costs include contingency allowances of 10% in each case.

Table 4: Primary substation equipment projects provided for review

Project name	Business case approval date	Project completion date	Plant age at completion	Actual life - repex model life	Approved cost ($m)	Final cost ($m)	Cost difference ($m)
Blackwater substation replacement	2014	2016	43	9	$ 11.9	n/a	n/a
Nebo primary plant replacement	2013	2018	35.5	2	$ 22.5	n/a	n/a
Collinsville 132kV substation replacement	2011	2015	48	11	$ 33.7	$ 31.6	$ (2.10)
Callide A switchyard	2014	2017	54	14.2	$ 34.8	n/a	n/a
Swanbank B 275kV substation rebuild	2010	2015	46	9.1	$ 57.9	$ 60.4	$ 2.50
Gladstone substation replacement	2009	2014	39	-0.8	$ 170.6	$ 127.0	$ (43.60)
Total					$ 331.4		

Source: EMCa analysis of Powerlink project documentation provided via the AER
Note: the age of the assets at completion was derived from the average age of the assets; the repex model replacement life was derived from the average of the primary asset types replaced

5.2 Project assessment

5.2.1 Blackwater substation replacement

The need for the investment

99. Powerlink's 2014 revision of the condition assessment at the Blackwater Substation identified that replacement of plant and equipment in bays D02 to D08 (1969 and 1979 vintage) was required to address condition and obsolescence issues. Replacement was recommended within 3-5 years (i.e. 2017-2019).[27] The CAR noted that other parts of the substation are newer and in better condition with the earliest replacement required in 10 to 15 years' time.

100. Powerlink used a scoring system to help determine the treatment in cases where the condition or related factors (such as obsolescence) have deteriorated materially. The scoring system results in scores out of 100 for 'serviceability' and 'compliance' (with Powerlink standards). In this case, the serviceability score was 69 (and the 'compliance score' was 66), which according to the scoring system indicates the need for either minor asset replacement or refurbishment.

Options analysis and scope of work

101. Three options were considered for the replacement of the affected bays at Blackwater Substation:

- Option 1 - Brownfield partial like for like replacement.
- Option 2- Brownfield partial replacement and conversion to arrangement.
- Option 3 - Greenfield partial like for like replacement.

[27] It is possible that the author was referring to 2016 as the starting point of the recommended replacement timing range as version 2 of the report was written in 2013. Powerlink should have clarified this point in subsequent (2014) revisions.

102. Option 1 was selected as it had the lowest net present cost. The estimated cost is $11.85 million and it is scheduled to be completed in 2016.

EMCa observations

103. There is sufficient information in the CAR to demonstrate that some form of action is required to address obsolescence and condition issues within a 'few years'. However, the serviceability rating of 69 indicates only minor asset replacement or refurbishment is required. The primary plant will be between 35-47 years old when it is replaced in 2016. This means that the replacement life for the equipment is on average 7.5 years longer (21%) than the 35.5 year average replacement life used in the repex model for primary plant.

104. We do not consider that the compliance score is a driver for replacement in accordance with the requirements of the NER. Powerlink did not appear to use the compliance score as a key determinant for initiating the project.

105. The project is scheduled to be completed in advance of the 3-5 year window recommended in the CAR. Powerlink offers no explanation for the 'early' timing. Risk assessment in accordance with good industry practice is not included in Powerlink's analysis. There is limited risk-cost trade-off assessment to confirm the optimal timing of the replacement.

106. Powerlink only considers replacement options and has selected the least cost approach, which is the best approach from the three options considered. However, Powerlink has not considered full or partial replacement/refurbishment options to extend the life of the equipment further (including 'cannibalising' replaced plant and equipment for spare parts to overcome obsolescence issues).[28]

5.2.2 Nebo primary plant replacement

The need for the investment

107. The assessment determined scores of 59.5 out of 100 for serviceability using Powerlink's scoring system. According to Powerlink's CAR, this indicated that Nebo Substation requires major asset replacement. The major issues with the primary plant were oil leaks, gas leaks, deteriorated condition and obsolescence associated with the original primary plant.

Options analysis and scope of work

108. Two options were considered:

- Option 1 - in situ partial replacement; and
- Option 2 - adjacent partial replacement.

109. Both options involve replacement of identified plant at the Nebo Substation, including primary plant and replacement of the secondary systems on two 132kV bays associated. Option 1 was selected as it had the lower NP cost of the two options. The project is scheduled to be completed in 2018 at a cost of $22.5 million.

[28] Note that this is not to say that alternatives to the option selected are superior to the selected option, merely that a comprehensive options assessment should consider all viable options, including the do-nothing counterfactual

EMCa observations

110. The substation was established in 1977 and the primary plant in question was 33 years old when the CAR was written. Obsolescence is said to be a prevalent driver for replacement of the identified circuit breakers (CB). There are also several CB type-defects. The CBs nominated for replacement within 7 years were 31-33 years old when the CAR was written, although other CBs were only 15 years old. The condition assessment score for the CBs indicates a significantly worse condition than is evident from the qualitative evidence provided in the CAR.

111. No quantitative analysis is provided to support the condition assessment of the CTs and VTs (e.g. no defect curves). The CTs and VTs recommended for replacement within 7 years were 23-33 years old when the CAR was written. The lack of quantitative analysis and the lack of explicit condition assessment scores both undermine confidence in the rating and recommended replacement timeframe.

112. Powerlink has selected the least cost option of the two it considered. However, limited quantitative risk-cost trade-off analysis is provided to demonstrate that the optimum replacement time has been selected. Furthermore, Powerlink has not considered full or partial replacement/refurbishment options to extend the life of the equipment further (including 'cannibalising' replaced plant and equipment for spare parts to overcome obsolescence issues).

113. The average age at replacement will be 35.5 years which is an average of 1.5 years longer than the average replacement life for this equipment in Powerlink's repex model.

5.2.3 Collinsville 132kV substation replacement

The need for the investment

114. The Collinsville 132kV Substation is identified by Powerlink as an essential 132/33kV bulk supply point for Ergon Energy to supply the Collinsville township and its surrounding area, and as a connection point for the Collinsville Power Station. The CAR identified that deteriorating plant condition was giving rise to maintenance and supply reliability issues. Using Powerlink's scoring system, Collinsville Substation was assessed as requiring a significant or total replacement, with a score of 52 out of 100 for serviceability and 53 out of 100 for compliance.

115. The supply capacity was approaching the capability of the No.1 transformer. Replacement with a higher rated transformer was required to meet load growth.

Options analysis and scope of work

116. Powerlink considered two options:

- Option 1 - In-situ replacement.
- Option 2 - Adjacent new-site replacement.

117. The in-situ replacement option required multiple stages of complex construction works in limited space, greater integration between construction, and demolition and more detailed coordination for cut-over and outages. According to Powerlink, these requirements would have imposed delivery risks and costs in excess of the savings obtained by using the existing site rather than a new site. The new site option was the lower cost solution and was selected by Powerlink at a total cost of $33.7 million to be completed by 2013.

118. Powerlink incorporated a 60MVA transformer into the project to meet forecast load growth, doubling the original 30MVA rating.

EMCa observations

119. The serviceability ratings in the CAR appear to be conservative (i.e. bias towards low ratings requiring full replacement) considering the evidence in supporting photographs. The descriptions in the CAR suggest that had some preventive maintenance been undertaken at an earlier date, the major replacement of the substation could have been deferred until the future demand and power station connection had become more certain.

120. Given the reported state of the substation assets, replacement options were likely to be the only reasonable options available at the time the business case was considered. However, risk assessment in accordance with good industry practice is not included in Powerlink's analysis. Furthermore, there is limited risk-cost trade-off assessment to confirm the optimal timing of the replacement. As a subset of Option 1, Powerlink should have considered the option of reducing the extent of the replacement work by more targeted replacement of assets representing major risks only. Rebuilding on an adjacent site was likely to have been the best option of the two considered.

5.2.4 Callide A switchyard replacement

The need for the investment

121. The substation was established in 1962 and at the time the primary plant CAR was written it was 51 years old. The substation was expanded in the 1980s with the Callide B power station and Calvale feeder bays and underwent minor refurbishment in the 1990s. The existing secondary systems at the Callide A substation were installed between 1984 and 1997. A secondary systems CAR was written in 2010. On the basis of individual Health Index scores for each item of plant, the primary plant CAR recommended bringing 'the assessed assets and equipment at T022 Callide A substation up to a condition suitable for at least a further 15-20 years of service.' According to the Business Case: '*… the complete secondary systems and major components of every primary plant bay need to be replaced.'*

Options analysis and scope of work

122. Powerlink considered two options:

- Option 1 - in situ replacement; and
- Option 2 - adjacent replacement.

123. Both options identified would address the need. Powerlink approved adjacent replacement of the Callide A substation (switchyard) at an estimated cost of $34.8 million and this is scheduled to be completed in 2017.

EMCa observations

124. Powerlink considers the switchyard to have an 'enduring purpose.' Obsolescence associated with secondary systems after 20-25 years is common industry experience and proactive replacement prior to end-of-life is common industry practice, although usually after applying life extension practices such as using spare parts generated through progressive replacement of the same equipment type. The secondary systems at Callide A range from 17-30 years old. Based on the age of the plant/equipment, the condition

information and reported obsolescence issues, there is a reasonable case for replacing the older primary and secondary systems equipment within the next 10 years.

125. Powerlink applied a Replacement Index Methodology[29] to this project. As with Powerlink's other scoring system, it is a quantitative approach that involves assigning a health index as a condition indicator.

126. It is not clear why corrosion of foundations and bus work had reached the point where replacement appears to be the only viable option. Inadequate preventative maintenance may have been the cause. Nonetheless, the primary plant is planned to be replaced in 2017. The average life of the replaced plant will be 17 years (56%) longer than the average primary plant replacement life assumed in the repex model. On this basis, there is likely to be limited scope for economic deferral.

5.2.5 Gladstone substation replacement

The need for the investment

127. Gladstone substation was built in 1975 in conjunction with the Gladstone Power Station and was located in a coastal environment. It was a major substation in the 275 kV and 132 kV transmission networks with major generation input at both voltage levels and interconnection between the systems.

128. Transfield undertook the condition assessment for Powerlink in 2005, when the substation was 30 years old, and rated it at a 'serviceability' level of 60.6 out of 100 and a 'compliance' level of 55.5 out of 100 using a set of condition ratings. A score between 55 and 65 indicates that major refurbishment is required.[30] Transfield concluded at that time that:

- The transformers were in poor external condition and should be refurbished if they were required for a further 20 years;
- The secondary equipment required corrective actions within 5 years and the switchyard within 2 years. The concrete support structures required action within 2 years. The majority of the secondary equipment and switchyard was not in accordance with the current Powerlink design standard; and
- The main building was considered to be in reasonable condition but required some maintenance actions.

Options analysis and scope of work

129. Powerlink considered only two replacement options:

- Option 1 - In-situ full replacement.
- Option 2 - Full replacement on a new site.

130. Option 2 was estimated to cost 13% less than Option 1 and was less complex and posed less risk to operations during the construction phase. Replacement of the Gladstone Power Station 275kV and 132kV substations at a greenfield site (Calliope River Substation) was approved at an estimated total cost of $170.6 million to be completed in 2013.

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[29] As described in the Callide A Condition Assessment Report Nov 2013, section 5.2

[30] A total score of ≤55 indicates total replacement is required

EMCa observations

131. Powerlink's 2009 Business Case differed from Transfield's 2005 recommendation, concluding that: '*The functionality and rating of existing primary plant and secondary systems is not capable of reliable operation into the future…There is little of the existing substation equipment or infrastructure that can be retained in the longer term which precludes a feasible life extension option….The management of fault levels that are rising due to network augmentation occurring at sites directly connected to Gladstone since its original installation is an issue. Operational measures are in place to manage fault levels to within the plant rating, but these measures become unsustainable with the continued augmentation of the 275kV network around Gladstone PS switchyard and these limitations will contribute to reduce network performance. There is currently no capacity to allow connection of new generation in the Gladstone region*.'

132. Powerlink advises that in calibrating its repex model, it has removed the quantities and cost associated with load-driven expenditure, including plant upgrades to manage fault levels undertaken in this project.

133. The condition of the substation plant and equipment indicates that inadequate maintenance was undertaken prior to the 2005 CAR. It would appear that in the four years between the delivery of the CAR and the Board submission, the recommended life extension activities were not undertaken.

134. In the absence of evidence to the contrary, it is reasonable to conclude that Powerlink adopted a run-to-fail strategy cognisant of potential load- and generation-driven reasons to upgrade the substation. It would appear that on a condition basis alone, refurbishment of the assets could have economically extended the replacement life of the primary assets.

135. The project was completed in 2014, 12 months later than the approved date at a cost of $127.0 million, $43.6 million (26%) less than estimated. Its replacement life was 39 years, which is 5 years older than the replacement life assumed by Powerlink in its repex model for some of the primary plant assets[31] and commensurate with the assumed replacement lives of others.[32]

5.3 Summary

136. Powerlink's Condition Assessment Reports are generally sufficient to demonstrate that at least some of the key substation assets will require replacement within 10 years from the assessment without remedial action. Some elements of equipment required treatment in the short term (i.e. replacement or refurbishment).

137. Powerlink undertakes limited options analysis, both in terms of the range of options considered and the depth of analysis. There is, for example, inadequate cost-risk trade-off analysis to demonstrate that the economically efficient timing for the work has been selected.

138. For the projects considered, the average replacement life of the primary plant assets was 7 years (21%) longer than the average of the primary plant replacement lives used by

[31] Circuit breakers, VTs and CTs

[32] Isolators and earth switches

Powerlink in its repex model. Either by omission or commission, Powerlink appears to have foregone the opportunity to extend the life of its primary assets through more or better targeted replacement or refurbishment. If asset management practices were to change to focus more on life extension, this too should be taken into account in the repex model (or adjustments made to it).

139. Powerlink advises that it has removed load-driven expenditure from its inputs to the repex model. This is an appropriate step, however the accuracy to which this has been done has not been verified by EMCa as part of this review.[33]

140. We note that Powerlink has not included power transformer investments in its repex model, '*being low volume and high cost items'*.[34] In our view, the bespoke nature of the primary plant replacement projects and their high cost (i.e. much higher than transformer replacement projects) present similar challenges for repex modelling and it could be argued that these projects are not amendable to a repex modelling approach.

[33] Powerlink advises that the adjustments equate to a reduction of 9% compared to historic replacement & refurbishment expenditure (referred to as reinvestment by Powerlink) (Source: Powerlink's response PQ0178 to EMCa's information request)

[34] Powerlink, Non-Load Driven Network Capital Expenditure Forecasting Methodology, page i

6 Assessment of secondary systems projects

6.1 Introduction

141. Five projects were provided for assessment that were predominantly secondary systems replacement projects. The Mudgeeraba and Ross projects were not included in calibrating Powerlink's repex model. The projects are shown in Table 5.

142. The average replacement life of the secondary equipment was 27 years. Three of the projects are still in progress, so a final cost is not available. The approved project costs include contingency allowances of 10% in each case.

Table 5: Secondary systems replacement projects provided for review

Project name	Business case approval date	Project completion date	Plant age at completion	Actual life - repex model life	Approved cost ($m)	Final cost ($m)	Cost difference ($m)
Mudgeeraba 110kV rebuild	2015	2018	20	0	$ 15.6	n/a	n/a
Moranbah secondary systems replacement	2010	2014	35	15	$ 19.2	$ 16.00	$ (3.20)
Bouldercombe secondary systems replacement	2010	2014	35	15	$ 20.6	$ 18.20	$ (2.40)
Bulli Creek iPASS secondary systems replacement	2011	2015	15	-5.2	$ 22.3	$ 24.80	n/a
Ross secondary systems replacement	2013	2017	32	11.8	$ 27.0	n/a	n/a
Total					$ 104.7		

Source: EMCa analysis of Powerlink project documentation provided via AER

6.2 Project assessment

6.2.1 Mudgeeraba 110kV rebuild

The need for the investment

143. The original assets were installed in 1971. A program of primary plant replacement occurred at Mudgeeraba 110kV Substation in 2006 to address critical fault rating and continuous current rating limitations. The scope included replacement of selected primary plant using the existing structures and foundations. As a result of the previous work and revised demand outlook, the scope of work proposed here formed part of a strategic solution to maximise use of the assets and minimise asset write downs and future rework. The condition assessments identified that equipment on the 110kV and 275kV primary and secondary systems that was not replaced in the previous work, required selective replacement on the basis of condition and fault level limits within a 1 to 5-year time frame.

Options analysis

144. Three primary plant options were considered:

- Option 1: Partial 110kV switchyard replacement with AIS ($60.0m)
- Option 2: Complete 110kV switchyard replacement with AIS ($64.2m)
- Option 3: 110kV switchyard replacement with GIS ($59.0m)
- Option 4: Selective primary plant replacement (under $1.0 m)

145. Each of the options 1-3 included complete replacement of the 110kV secondary systems. Three further options for secondary systems replacement were considered:

- Option 1 – Minimal Relay Replacement
- Option 2 – Partial Secondary Systems Replacement
- Option 3 – Full Secondary Systems Replacement

146. Powerlink recommended primary plant option 4 (Selective primary plant replacement) and secondary systems option 2 (Partial Secondary Systems Replacement) as the most cost effective approach to address the condition, ongoing requirements and development constraints of the primary plant and secondary systems. The total cost is estimated to be $15.6 million and it is scheduled to be completed in 2018.

EMCa observations

147. In this more recent project assessment (completed in 2015), Powerlink has demonstrated consideration of a range of options which enable assessment of least cost approaches to address asset condition and fault level constraints. Risk assessment in accordance with good industry practice is not included in Powerlink's analysis. There is limited risk-cost assessment to confirm the optimal timing of the replacement.

6.2.2 Moranbah secondary systems replacement

The need for the investment

148. Moranbah Substation was established in the mid-1970s and subsequently extended in the early 1980s through to the mid-1990s and late 2000s. Extensions have resulted in a

mixture of secondary systems equipment and primary plant from the original installation through to the mid-1990s and late-2000s. Powerlink's secondary systems CAR was written in 2007, updated in 2009 and reviewed in 2010. The CAR states that: '*Defect history reveals that since 1st July 1999 no single item of secondary systems equipment has been problematic. Past experience has shown that with the type and age of the secondary systems installed at Moranbah, component failure will occur more frequently as the relay age increases*.' The CAR also states that: '*The control and automation equipment is in need of replacement in the short term due to obsolescence of the RTUs, in particular the inability to repair RTU faults and the state of the control panels. This is the trigger that initiates the total secondary system replacement.'*

149. No CAR for primary equipment has been provided. The Business Case states: 'Condition assessment of the primary plant has confirmed that selected instrument transformers and circuit breakers are required to be replaced due to obsolescence, plant condition, and emerging reliability issues.'

Options analysis

150. Two options were considered in the Business Case:

- Option 1: Secondary Systems and Selected Primary Plant Replacement – secondary systems equipment and selected primary plant installed prior to mid-1990s were to be replaced by 2012. This included eleven 132kV bays.
- Option 2: Full Secondary Systems and Primary Plant Replacement – Under this option, the secondary systems equipment and primary plant at Moranbah Substation were to be fully replaced by 2012. Secondary systems equipment installed in late 2000s, and the remaining 132kV primary plants was to be replaced earlier than the timing that would be required based on condition and performance.

151. Option 1 was selected on the basis of a lower NPV (more correctly a net present cost). The estimated capital expenditure required was $19.2 million and was scheduled to be completed in 2012. It was completed in 2014 at a cost of $16.0 million (-17%). $1.4 million of accelerated depreciation was approved to apply to the existing secondary systems equipment being replaced.

EMCa observations

152. The secondary systems equipment installed prior to the mid-1990s would be older than 17 years when replaced. The actual age of the equipment is not discernible from the CAR. There is no analysis of defects to support qualitative statements about reliability deterioration and risk in the CAR and the CAR does not apply any form of rating system. It is not obvious from the documentation provided why the replacement of obsolescent Foxboro RTUs triggers total secondary system replacement. It would appear that supplementary issues such as historical data on design deficiencies, inability to work on panels without significant risk of injury, and safety and security concerns are given as much weight as the secondary system equipment risk.

153. The options analysis considers only two options, both of which include replacement of all secondary systems equipment over 17 years old. In our view, Powerlink should have considered a more selective equipment replacement option directed at the highest risk (and probably older) assets such as the obsolete RTUs. Whilst it has selected the lowest cost option of the two it considered, the options analysis has not provided compelling information that it has selected the prudent and efficient expenditure option.

154. The secondary systems equipment installed in the late 1970s would have been 35 years old when it was finally replaced, which is well in excess of the 20.2 year replacement life used in Powerlink's repex model.

6.2.3 Bouldercombe secondary systems replacement

The need for the investment

155. The original assets were installed in 1971 but the existing secondary systems equipment was installed in 1979 and in the 1990s. Condition assessments were undertaken in 2007 and in 2010. The 2010 report indicated that: (i) no single item of secondary systems equipment was especially problematic to substation reliability; (ii) the majority of secondary systems maintenance costs are associated with scheduled routine maintenance; and (iii) the routine maintenance on the ageing equipment has been successful to date but based on past experience the reliability of this equipment will decrease with component ageing.

156. The CAR cites '*maintainability issues, including costs of labour, skills shortage and repair turn-around time of faulty or ageing discrete electronic components within protection relays and their power supplies indicate relay reliability decreasing with the age of the components. Another issue is the lack of manufacturer's support for the replacement or the repair of L&N RTU electronic cards.*' It concludes that: '*Condition assessment recommends that a complete 275/132 kV secondary systems and panel upgrade be conducted at Bouldercombe in 2 – 4 years.*'

Options analysis

157. Powerlink's Business Case discusses two options:

- Do nothing – which is dismissed as technically unacceptable.
- Replacement of the 275kV and 132kV secondary systems equipment.

158. The replacement option was recommended '*as it is the only option that addresses the condition, lack of manufacturer support and reliability issues associated with the secondary systems at Bouldercombe Substation.*' Powerlink also decided to replace secondary systems for the 132kV feeders not identified for condition-based replacement '*to enable efficient integration with the changes to the bus protection schemes'* required as part of establishing a 132kV bus coupler (under another project).

159. The estimated capital expenditure required was $20.6 million and was scheduled to be completed in 2013. It was completed in 2014 at a cost of $18.2 million (-12%). $2.3 million of accelerated depreciation was approved to apply to the existing secondary systems equipment being replaced.

EMCa observations

160. Secondary systems equipment that has been in service for over 25 years is likely to be obsolete or nearly so and require careful spares management to extend the technical life. The equipment installed in 1979 was 31 years old when the second CAR was written. It seems reasonable to replace the 1979 vintage assets by 2014 at which time they would be 35 years old. The date of installation of the '1990s' vintage equipment is not nominated, but would be between 15 – 25 years old in 2014. There is little evidence in the CAR to support the replacement of the 1990s equipment at that time.

161. The project not only involved replacing the equipment deemed to be obsolete/poor condition or prone to increasing reliability defects, but relatively new and healthy equipment. No quantitative risk analysis is presented and only the single alternative to doing nothing is presented. The justification provided for the replacement of the whole secondary system (including some panels and marshalling cubicles) is not compelling. It results in writing off over $2m of assets due to early replacement). Whilst NPV-based comparative analysis is presented for the options, there is no cost-risk trade-off analysis for the selected option to demonstrate that the timing is justified for the total project (i.e. including replacing the relatively 'healthy' secondary systems equipment.

162. At 35 years, the replacement age for the 'unhealthy/obsolescent' Bouldercombe secondary equipment was 15 years (73%) higher than the repex model replacement life of 20.2 years.[35]

6.2.4 Bulli Creek iPASS secondary systems replacement

The need for the investment

163. The substation was built in 2000 and extended in 2003. The substation was one of six substations in the world with ABB iPASS design technology. Powerlink states that the ABB iPASS technology was to become obsolete in 2013, requiring replacement before then. iPASS secondary assets and iPASS communications gear installed on primary assets required replacement. For the primary plant e.g. circuit breakers, ABB had developed a refit kit to upgrade the iPASS and this was being fitted under another project at Loganlea substation. This project covered only the iPASS secondary assets.

Options analysis

164. Powerlink identified three options:

- Option 1: Do Nothing - This option was deemed not acceptable due to the termination of manufacturer support.
- Option 2: Full 'iPASS' Secondary Systems Replacement with conventional technology - This option was not considered to be technically feasible.
- Option 3: Full 'iPASS' Secondary Systems Replacement with IEC61850 technology[36] and retrofit kit for primary plant.

165. Option 3 was Powerlink's preferred option as it was deemed the only option that addressed the manufacturer support requirement. The estimated cost was $22.3 million, comprising $19.2 million for prescribed transmission services and $3.1 million for non-regulated transmission services. It was scheduled for completion in 2013. The project was completed in 2015 at a cost of $24.8 million. The asset write-off was to be $2.5 million.

EMCa observations

166. The need for the expenditure was the looming obsolescence of the ABB iPASS secondary systems equipment. The scope of the works reflects the broader iPASS replacements across six substations and also the interconnection issues that had to be addressed, for

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[35] Powerlink, *Revenue Proposal 2018-2022, Appendix 5.05* and PQ0142

[36] IEC61850 was developed in 1995. The iPASS would therefore be expected to have conformed to the standard as it was installed in 2000. So this is not a new standard.

example with TransGrid. Given the need for all components of the system to operate on the same platform, it is reasonable that the scope was for a comprehensive replacement.

167. The plan for replacement of the iPASS-related secondary systems equipment after only 13 years of operation is well under the typical secondary replacement lifetime. This project is for a solution that is quite specific to the asset type, location and configuration, system and manufacturer. Accordingly, we question whether these non-representative equipment types should be included in calibrating the repex model, as they appear to incur a high cost and have a short survival live, both of which bias the repex model outputs towards overstating overall expenditure requirements.

6.2.5 Ross secondary systems replacement

The need for the investment

168. Ross 275/132 kV substation was established in 1985. Subsequent secondary system changes were made between the late 1990s and 2001, then again in 2010 and 2012.[37] This resulted in a mixture of secondary systems equipment from the original electromechanical relays in 1985 to microprocessor based relays in 2001 and the early 2010s.

169. According to the 2013 CAR, the secondary systems equipment installed in 1985 was, at 28 years old, experiencing obsolescence and reliability issues. No defect analysis was presented.

Options analysis

170. Two options were considered to address the identified issues:

- Option 1 - Secondary systems replacement in two stages – stage 1 is to replace all equipment installed in 1985 by 2017; the second stage is to replace all equipment associated with modifications to the two 275kV feeder bay panels associated with the Strathmore Substation and one 132kV feeder bay panel to Millchester Substation by 2023.
- Option 2 - Secondary systems replacement in one stage – all the equipment denoted under option 1 is to be replaced by 2017.

171. According to the Business Case, the NPC of the options were similar. Option 2 was selected *'having considered the benefits and risks of each option*'. The estimated cost was $27.0 million and it is to completed by 2017. $3.5 million accelerated depreciation was recommended to be applied to the existing assets being replaced.

6.2.6 EMCa observations

172. When it is replaced in 2017, the 1985 equipment will be 32 years old, which is 12 years longer than the repex model standard replacement life for secondary systems equipment. By then the late 1990s/2001 equipment would be only 15-16 years old and the 2010-2012 equipment would be 5-7 years old. Insufficient compelling justification is presented for including the late 1990s/post 2000 equipment for replacement. The relatively high recommended asset write-off of $3.5 million is indicative of the young technical and economic life of the equipment proposed to be replaced.

[37] The Business Case and CAR contain conflicting information

173. If the replacement of this relatively young equipment is included in the derivation of the repex model replacement life for secondary systems, it is unjustifiably lowering the average replacement life. This in turn biases the repex model to early replacement and more expenditure than necessary.

6.3 Summary

174. In the majority of projects considered:

- The qualitative information indicates the need for corrective action on the older secondary systems equipment on the grounds of condition and/or obsolescence but to some extent a 'leap of faith' is required in accepting the assessment because of the lack of quantitative defect analysis;
- The qualitative condition assessments do not support replacement of the more recently installed systems;
- The options analysis: (i) does not consider a broad range of possible options, including life extension or partial refit; (ii) does not include risk assessment in accordance with good industry practice; and (iii) included limited risk-cost assessment to confirm the optimal timing of the selected option;
- The actual age at replacement of the older equipment is significantly longer than the repex model assumes; and
- Selection of 'bundled' replacement of older and younger assets may help explain the relatively low replacement life derived by Powerlink for use in its repex model. It also leads to relatively high asset write-offs.

175. In summary, we consider that the historical expenditure is not likely to represent the prudent and efficient level required and that, in turn, the representation of the volume and quantity of secondary systems repex in the repex model is likely to bias the outputs to be higher than is prudently and efficient.

176. Similar to our observation regarding the bespoke nature and relatively high cost of primary plant replacement/refurbishment projects, we consider that secondary systems projects present the same challenges for predictive repex modelling.

7 Implications for proposed repex

7.1 Introduction

177. In this section we provide a summary of the findings from our review of the 18 projects in the context of the quality of the inputs to the repex model. Our perspective is focussed on two particular aspects:

(i) Is there evidence that Powerlink's repex in the 2010-2015 period was higher than the prudent and efficient level? If this is the case, the quantities used as inputs to Powerlink's repex model are likely to bias the outputs toward overestimation of the requirements for the next RCP; and

(ii) Were the actual survival lives of Powerlink's replaced assets in the projects considered comparable to the replacement lives used in Powerlink's repex model? The output of the repex model is strongly dependent on the assumed replacement lives and so comparing the actual replacement lives with the assumed replacement lives is a necessary test of the validity of the repex models outputs.

7.2 Identification of systemic issues in historical expenditure

Historical repex expenditure is likely to be higher than the prudent and efficient level

178. In the majority of projects considered:

- The condition assessment reports indicate the need for corrective action to subsets of the asset classes considered, but there is insufficient evidence to support replacement of the more recently installed assets. Accepting the assessment of the need for replacement or refurbishment on the grounds of condition and/or obsolescence requires a 'leap of faith' because of the lack of quantitative defect analysis;

- The options analyses typically (i) do not consider all technically viable options - in particular life extension options targeted only at the assets representing major risks; (ii) do not include risk assessment in accordance with good industry practice; and (iii) include limited risk-cost assessment to confirm the optimal timing of the selected option.

179. We consider that the historical expenditure is not likely to represent the prudent and efficient level required and, in turn, the representation of the volume and quantity of secondary systems repex in the repex model is likely to bias the outputs to be higher than is prudently and efficient.

180. However, we do not consider that the systemic issues applied to transformer replacement projects are likely to result in a material over-estimate of the prudent and efficient level required because of the reported condition of the transformers and taking into account the impact on the transformer Health Index of the proposed program noted in our initial report.

Actual survival lives are longer than used in the repex model

181. In all but a few of the sample projects the actual survival life of assets was significantly longer than the comparable asset replacement lives that Powerlink advises it used in its repex model.

182. Also we consider that Powerlink has replaced equipment that was well short of its economic end of life. Such plant and equipment was in several cases bundled with full replacement options (some of which were primarily load- or generation-driven) when partial replacement/refurbishment options could have been deployed to address the necessary asset condition/obsolescence issues. Evidence of 'bundling' and replacing relatively healthy (often young) assets is also evidenced from the asset write-offs that resulted from the replacement projects and which were at times significant. This would have the effect of reducing the average replacement ages that Powerlink has used.

Adoption of life extension strategies has been insufficiently considered

183. Further to considering the actual replacement lives of its assets, we consider that Powerlink had options to extend the lives of its assets by adopting earlier and less extensive replacement/refurbishment tactics to address critical conditions and targeted preventative maintenance.

184. Until about 2015, Powerlink appears to have applied asset management strategies biased towards replacement of assets rather than life extension. There is evidence that it is now deploying life extension techniques more broadly, rather than relying on replacement of assets in response to constant load and generation growth. We consider that evidence of tower deterioration and deterioration of other assets present in a number of Powerlink's reports is indicative of low levels of proactive refurbishment, including tower painting.

7.3 Implications of systemic issues for proposed expenditure

Over-estimation bias

185. Our review of the sample of 18 projects has identified evidence of biases that contribute to a likely overestimation of the repex prudently required in the 2018-2022 RCP through the use of Powerlink's repex model.

186. Although we assessed the four key asset categories separately, and not all categories are reflected in Powerlink's repex model, we consider that the biases evident in the sample of projects reviewed reflect systemic issues. As such, it is reasonable to conclude that similar issues and biases are likely to exist in the remainder of the replacement capital expenditure and its representation in the repex model.

187. We consider that these results are consistent with and support the findings of the issues we reported in our initial report to the AER and collectively form the basis for our view that Powerlink's expenditure forecast for the 2018-2022 RCP is likely to be excessive.

188. The AER has requested that we estimate the impact of the issues identified for Powerlink's proposed repex expenditure allowance for the 2018-2022 RCP.

189. We consider that the forecast repex for transformers in the 2018-2022 is likely to be a prudent and efficient level because (i) the condition of the transformers is, or is likely to be such that replacement is the only economically and technically viable option, and (ii) the volume of transformer activity is relatively low.

190. We have considered adjustments for the other three asset categories we were required to review from two perspectives:

(i) Adjustments to the assumed survival lives used in the repex models for the asset categories we considered; and

(ii) The impact of application of current best practice asset management techniques (particularly with respect to towers).

Adjustment to asset replacement lives to remove over-estimation bias

191. We conclude that the asset survival lives in Powerlink's repex model can reasonably be extended in recognition of:

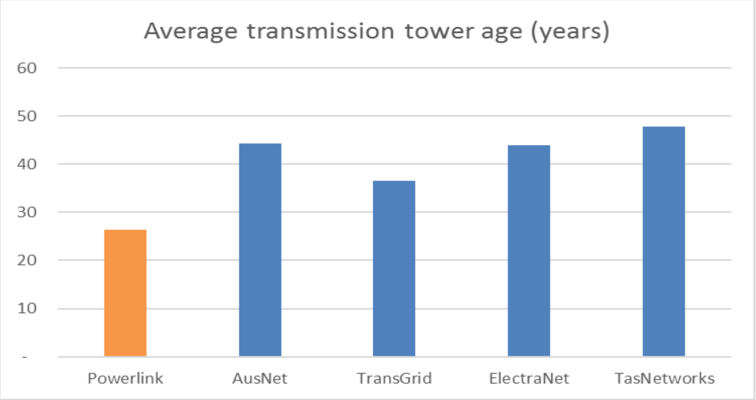
(i) The actual survival lives we found in our review;

(ii) The impact on survival lives from adopting a bias towards life extension rather than large-scale replacement; and

(iii) The relatively young age of Powerlink's assets compared with other NEM TNSPs, as shown in Figure 1 and Figure 2.

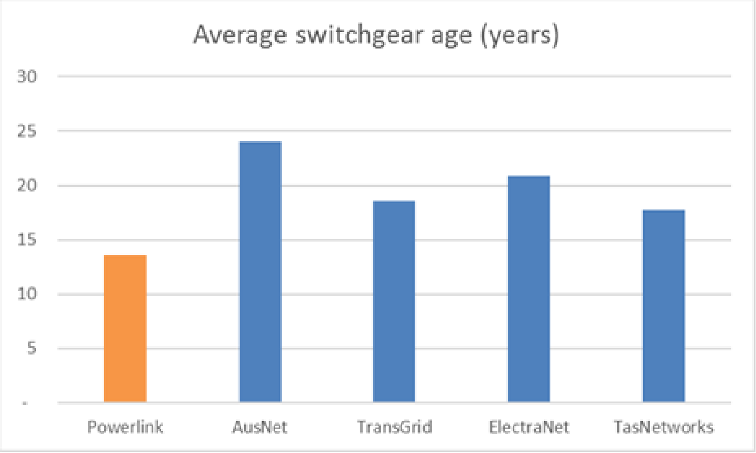
192. An adjustment to the replacement lives in Powerlink's repex model will, all things being equal, lead to a rise in the average age of Powerlink's assets. We consider that this is likely to be tolerable from a cost-risk trade-off perspective.

Figure 1: Average asset age comparison for transmission towers



Source: AER analysis

Figure 2: Average asset age comparison for switchgear



Source: AER analysis

Changes to the repex model to provide a reasonable predictive-based expenditure forecast

193. As shown in the table below, we consider that extending the assumed asset replacement lives by an average of one standard deviation from the mean results determined by Powerlink provides a reasonable estimate of the actual survival life for Powerlink's key asset categories.[38] This is because in most of the projects we reviewed, the actual replacement lives were significantly longer than Powerlink's assumed value. The average variance in actual replacement lives from those assumed by Powerlink (in the asset classes we considered) is similar to the average standard deviation seen in Powerlink's data. Based on our analysis, the higher asset replacement lives we recommend are likely to be more representative in practice of the actual replacement lives Powerlink will be able to achieve in the next RCP through robust options analysis and option selection.

[38] Noting that in the case of substation switchbay equipment, the average of the sub-category standard deviations (6 years) has been added to Powerlink's assumed replacement lives to arrive at the EMCa recommended replacement lives for each sub-category as representative of the variations we observed between the actual and assumed replacement lives.

Table 6: EMCa recommended replacement life assumptions for repex modelling purposes[39]

Primary category	Sub-category	Powerlink replacement life (years)	Standard deviation (years)	EMCa recommended replacement life (years)
Transmission towers (all voltages and circuit configurations)	Corrosion zone DEF	40.3	6.3	46.6
	Corrosion zone C	57.9	7.6	65.5
	Corrosion zone B	71.4	8.5	79.9
Substation switchbay equipment (all voltages)	Circuit breakers	34.2	5.8	40.2
	Isolators/earth switches	39.8	6.3	45.8
	Voltage transformers	34.6	5.9	40.6
	Current transformers	33.2	5.8	39.2
SCADA, Network control and protection	Secondary systems bay and non-bay (excl metering)	20.2	4.5	24.7
	Communications	10.7	3.3	no change

Source: Columns 1-4: Powerlink, Appendix 5.05, Non-load driven network capital expenditure, Table 9

Impact of application of current good industry practices

194. As a partial offset to the reduction in required replacement and refurbishment expenditure that would result from adopting longer asset replacement life assumptions, we recommend that the AER allows for a prudent increase in Powerlink's preventative and corrective expenditure on asset life extension, including earlier painting of transmission towers. We propose that an allowance of 15% of the initial repex forecast should be provided to support this increased activity, based on our estimate of the cost of the repex activity that we consider Powerlink should prudently adopt.[40]

7.4 Other matters

195. We note that Powerlink has decided to exclude transformer projects from its predictive modelling because they are relatively small in volume and high cost. The bespoke nature and high cost associated with the transmission line, primary plant, and secondary systems projects considered in this Addendum Report and in our initial report to the AER are less amendable to predictive modelling. We consider that, if used, such modelling should be for the purpose of indicative cross-checking and that a preferred approach is to use a more extensive combination of bottom-up project-based justification and predictive modelling to determine reasonable expenditure requirements for assets with such characteristics.

[39] See footnote 38

[40] See footnote 22 which explains the basis of the provision for transmission towers. This covers the largest component of Powerlink's proposed repex and we consider it reasonable to assume a similar allowance for earlier life-extending refurbishment of other plant.

Appendix A Sample project list

Table 7: Sample project list

Project reference	Project name
CP.01458	Central Region SDH Loop
CP.01679	Mudgeeraba 110kV Rebuild
CP.01942	Collinsville - Proserpine Coastal Section Replacement
CP.00882	Cardwell - Ingham 132kV Line Replacement
CP.00880	Tully - Cardwell 132kV Line Replacement
CP.00881	Ingham/Yabulu Sth 275/132kV Line Replacement
CP.01543	Mudgeeraba 275/110kV No. 2 and 3 Transformer
CP.01146	Blackwater Substation Replacement
CP.01396	Nebo 275kV/132kV No.2 Transformer Replacement
CP.02351	Nebo Primary Plant Replacement
CP.02039	Collinsville 132kV Substation Replacement
CP.01546	Callide A Switchyard Replacement
CP.01163	Swanbank B 275kV Substation Rebuild
CP.01780	Gladstone substation replacement (also referred to as Calliope River Substation Establishment)
CP.01019	Moranbah Secondary Systems Replacement
CP.01563	Bouldercombe Secondary Systems Replacement
CP.01493	Bulli Creek iPass Secondary System Replacement
CP.01293	Ross Secondary Systems Replacement