Optional Firm Access

Provide cost and lumpiness assumptions to the optional firm access prototype model

Report to

Australian Energy Market Commission (AEMC)

from

Energy Market Consulting associates (EMCa)

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www.emca.com.au

This report has been prepared to assist the Australian Energy Market Commission (AEMC) with its development of the prototype pricing model associated with the implementation of Optional Firm Access (OFA).

This report relies on information provided to EMCa by the current policy assumptions for OFA as published by AEMC, and associated data. EMCa disclaims liability for any errors or omissions, for the validity of information provided to EMCa by other parties, for the use of any information in this report by any party other than the AEMC and for the use of this report for any purpose other than the intended purpose.

In particular, this report is not intended to be used to support business cases or business investment decisions nor is this report intended to be read as an interpretation of the application of the NER or other legal instruments. EMCa's opinions in this report include considerations of materiality to the requirements of the AEMC and opinions stated or inferred in this report should be read in relation to this over-arching purpose.

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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 access, pricing and regulatory arrangements. EMCa has offices in Sydney and Perth.

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1 Introduction

1.1 Purpose of this report

1. AEMC have sought advice from EMCa:

   - To improve the cost reflectivity of the unit cost and lumpiness[1] assumptions used in the Optional Firm Access (OFA) costing model; and
   - On methods to expand or improve the current data set to increase the granularity of assets used in the model; and/or to improve the existing categorisation of assets.

2. We have reviewed the current approach to categorising the costs and lumpiness by AEMC, focusing on the use of the variable asset 'sizes', the breakpoint ranges currently adopted in the model, and the appropriateness of AEMC's simplifying assumptions.

3. We describe our methodology and assumptions used to develop an alternate costing model for improved granularity in this report. Our data, model and alternate input assumptions are appended.

4. The scope of this report did not include consultation with TNSP businesses or other industry participants in the NEM, nor did it include assessment of other elements of the model.

[1] In the PFAP model, assets are augmented in discreet size increments which the model documentation refers to as 'lumpiness'

1.2 Background to the OFA review

1.2.1 Overview

5. In February 2014, the Standing Council on Energy and Resources (SCER) directed the AEMC to develop, test and assess the optional firm access model that was proposed as part of the AEMC's Transmission Frameworks Review.

6. The purpose of the review is to inform the SCER on whether there are long term benefits associated with implementing the developed optional firm access framework and, if such benefits are identified, develop the optimal approach to implementation of the framework.[2]

7. SCER has requested the AEMC[3] to:

- Confirm or modify the design of the optional firm access model as a result of testing and evaluation;
- Engage with industry participants and governments to build understanding of the model and the potential impacts of its implementation; and
- Recommend whether to implement the optional firm access model, and if so, how it could be implemented.

8. The AEMC's work program is intended to assist government and industry participants to better understand the potential costs, benefits and risks of implementing optional firm access.[4]

1.2.2 Optional firm access pricing model

9. As part of the concept of OFA, it is proposed that TNSPs will be required to provide a firm access 'product' and to price that product on the basis of a pricing model. AEMC have developed a prototype firm access pricing (PFAP) model that implements the logic of a Long-run Incremental Cost (LRIC) pricing method as specified in the Transmission Frameworks Review in 2013.

10. We understand that AEMC intends to use the prototype model to help understand how the LRIC method could be implemented in practice, the strengths and weaknesses of using the LRIC method and its sensitivity to input data and other assumptions. *"The prototype will also feed into the AEMC's assessment of the costs and benefits of implementing optional firm access. If*

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[2] SCER letter to AEMC Chairman 28 February 2014 paragraph 5

[3] SCER letter to AEMC Chairman 28 February 2014 Attachment 1 Overall Objectives

[4] SCER letter to AEMC Chairman 28 February 2014 Attachment 1 Overall Objectives

OFA was to be implemented, a complete, more comprehensive version of the model would be developed."[5]

1.2.3 Independent review of the PFAP model

11. AEMC engaged EMCa to undertake an independent review of the prototype pricing model and we provided this report[6] to AEMC on 16th October 2014. Part of our advice was that improving the costing and lumpiness assumptions in the prototype pricing model could significantly improve its cost reflectivity.

12. The cost and lumpiness assumptions are held in the 'linetypes' input file. We understand that AEMC require the input assumptions to be a reasonable reflection of the sizes of each asset type and their installed costs in order to represent the costs of augmenting the transmission network according to the stylised methodology of replicating elements of the existing network.

13. AEMC have advised that the 'size' variables (L, M, H) currently ascribed to each asset element have been based on an assessment of the actual ratings of the existing elements, and hence the expansion 'cost' and 'lumpiness' is based on the ratings of the existing elements. The expansion 'lumpiness' variable (expressed in MW) allows for the non-incremental nature of upgrades to the network to be approximated.

14. We understand that notional new assets – to be added into the model as part of determining the cost of firm access – will be assumed to have a rating equal to the 'lumpiness' of the expansion. (For the purposes of developing the 'lumpiness' assumptions in this review, the effect of meshedness[7] is not considered.)

1.3 Our approach

15. We commenced with analysis of the current model data, to understand how the data is organised and how it is applied within the current model.

16. In our first report[8] to AEMC, we stated that:

> *'We consider that the PFAP model, as provided, does not suitably specify or cost the required augmentations. These are largely limitations of input data and the representation of input costs.'*

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[5] Australian Energy Market Commission 2014, *OFA: Access Pricing Stakeholder Workshop (Sydney/Melbourne) - 13 & 14 November 2014*, p15

[6] Energy Market Consulting associates 2014, *Optional Firm Access - Review of Prototype Firm Access Pricing Model*

[7] Refer to descriptions provided in the AEMC Pricing Prototype Program User Guide, available from AEMC

[8] Energy Market Consulting associates 2014, *Optional Firm Access - Review of Prototype Firm Access Pricing Model*

17. We have therefore developed an alternative costing model to generate alternative input assumptions for the OFA prototype pricing model to improve its cost reflectivity, including consideration of additional scale factors to provide greater granularity of the likely input costs.

18. We undertook a review of available reference information to populate the new costing model with specific focus on size / lumpiness and cost parameters using a building block approach to developing high level planning estimates. We reviewed our methodology against industry information and our own industry sources to develop our working assumptions.

19. We have populated the costing model with an initial set of costs, developed new input assumptions, and described our methodology to improve the cost reflectivity of the costing model. Alternate linetypes input files are provided in Appendices A and B.

20. We have developed a set of attributes and scaling factors that reflect variations in transmission augmentation costs and which can be used to further improve the asset cost reflectivity. Whilst the scaling factors have been detailed along with an application approach, these have not yet been applied to individual assets. This is subject to a separate assessment and implementation that AEMC can then choose to undertake.

1.3.1 Data sources

21. We have used a combination of data sources in preparation of our advice. Our primary sources of reference information for the functional design and operation of the model are:

- Data files provided by AEMC[9] – being the linetypes and regional aemc_lines files;
- The Pricing Prototype Program User Guide, which is undated, and was provided to us by AEMC; and
- Our first report to the AEMC (*Review of Prototype Firm Access Pricing Model*).

22. Our primary sources of reference information for the transmission lines and transformer parameters have been:

- AEMO transmission unit cost estimates (where available). AEMO have developed transmission unit cost estimates to assist in developing high level planning-type estimates, described as first level 'order of magnitude'

[9] The linetypes and aemc-lines files form part of the version of the PFAP model made available to stakeholders by the AEMC to accompany the Supplementary Report on Pricing (31 October 2014), hereafter referred to as the October 2014 version.

estimates. AEMO state[10] that the estimates that do not take into account geographical or local conditions that would apply to any given project;

- Cost estimation studies available in the public domain, such as those prepared for and by AEMO and TNSPs within Australia and overseas; and
- Our own sources of planning and cost estimate information.

1.4 Structure of this report

23. The structure of this report is as follows:

Section	Title	Content
1	Introduction	This section sets out the purpose, scope and approach of our report.
2	Our observations of the current model	The section provides our observations from our review of the current model and simplifying assumptions.
3	Our costing model	This section provides the methodology for ratings and cost parameters used within our alternate costing model for asset costings, as an input to the AEMC prototype pricing model.
4	Attributes and factors	This section details the attributes and factors as a method to improve the cost reflectivity of asset costings.
5	Application of the costing model	This section provides a summary of the output of the costing model and compares the output to the original asset costings.
6	Implications and conclusions	This section summarises the improvements and implications of the alternate costing model and attributes on the current PFAP model.
Appendix A	This appendix contains an updated copy of the linetypes file (fixed and variable unit costs).	
Appendix B	This appendix contains an updated copy of the linetypes file (variable unit costs only).	

[10] Australian Energy Market Operator 2012, *100 per cent renewables study – electricity transmission cost assumptions*, Version 1.0, http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes

Section	Title	Content
Appendix C	This appendix provides our observations from review of the current model data.	
Appendix D	This appendix contains a bibliography.	
Attachment A	A copy of the costing model used in our advice is provided as an attachment.	

2 Our observations of the current model inputs

24. This section of the report provides our observations from our review of the current data and the methodology applied within the current model inputs, specifically the region input files.[11]

2.1 Our understanding of the stylised model assumptions

2.1.1 Transmission overview

Overview

25. Electricity transmission is the transportation of power from generators to electricity distribution networks.[12] AEMC also state:

> *'Transmission lines, when connected with each other, become a transmission network. Transmission networks include the towers which support high-voltage wires, underground cables, transformers, switching equipment, and monitoring and communications equipment. The transmission network connects generators to each other, to large demand customers and to the distribution system. It stops at substations where electricity is transferred to lower voltages for supply to consumers through the distribution network.'*

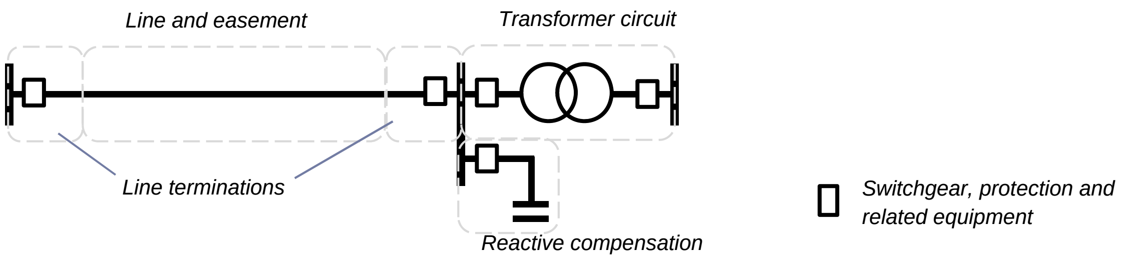
[11] As supplied by AEMC in the October 2014 version of the PFAP model.

[12] Australian Energy Market Commission 2013, *Fact Sheet - What is transmission?*, http://www.aemc.gov.au/Markets-Reviews-Advice/Transmission-Frameworks-Review/

Major components of a transmission network

26. The definition of a transmission network provided above concludes that the network is made up of a number of components. Each component and its corresponding function can be explained in general terms as shown below.

Figure 1: Major asset categories



27. The major functions of these components include:

- *Transmission lines and easements* – to connect nodes together to form a network;
- *Line terminations* – comprising switchgear, protection and related equipment to provide terminations and connections of lines;
- *Transformer circuits* – comprising the transformer itself, switchgear, protection and related equipment to provide voltage transformation and voltage control to support operation of the transmission network; and
- *Reactive compensation* – to provide voltage support, supporting power transfer across multiple parts of the transmission network.

28. The line terminations, transformer circuits and reactive compensation equipment are contained within switchyards or terminal stations, collectively referred to as substations.

2.1.2 AEMC's stylised model

Approach to determining cost

29. The Optional Firm Access prototype pricing model is a prototype that is still in 'draft' form, with inputs that are intended to be representative of the final product, but not yet ready for deployment.

30. The AEMC's design brief for the model acknowledges that it will produce LRIC prices using stylised representations of the network, its flows, constraints and augmentations.

31. The AEMC has applied a simple stylised model based on only two network elements – lines and transformers – where the costs associated with each of the components are allocated to the lines and transformers elements.

32. The model defines a 'cost' variable with units of $/MWkm for lines and $/MW for transformers. Normalisation of the cost by MW provides an ability to differentiate cost based on lumpiness.

Asset size

33. The sizes of assets are a function of the operating requirements of the network. The stylised prototype model has adopted three 'size' variables – low, medium and high (L, M, H), currently ascribed to each asset element based on an assessment of the actual ratings of the existing elements.

34. The 'size' variable is used by the model to 'look-up' and apply the characteristics of an asset corresponding with the same voltage and size variable where expansion to the network is required.

35. The size generally relates to a range of 'lumpiness' parameters at a specified operating voltage.

Lumpiness

36. AEMC include expansion 'lumpiness' (expressed in MW) to allow account to be taken of the non-incremental nature of upgrades to the network.

37. The use of units of MW (rather than MVA, by assuming a unitary power factor) is a further simplifying assumption.

38. New assets are assumed to have a rating equal to the 'lumpiness' of the expansion. For the purposes of developing the 'lumpiness' assumptions in the input file, the effect of meshedness is not considered. Meshedness is addressed separately in the PFAP stylised network design assumptions.

39. The 'lumpiness' variable is used by the model to build-up the capacity requirement for firm access. For example, new lines with the same voltage and size variable as the existing line are added until the total capacity just exceeds the capacity requirement determined by the model.

2.2 Review of existing region data

2.2.1 Overview

40. We have undertaken a broad level review of the stylised model to provide us with context for our review of the unit cost input data.

41. We have not investigated the model's representation of network topology, nor reviewed the accuracy of any data that was contained in the pricing model, which represents the existing transmission network in the NEM.[13]

[13] The October 2014 version of the model.

2.2.2 Modelled lines data

42. We undertook a review of the regional element data for the NEM to:

- understand AEMC's data classification;
- identify potential areas of improvement to the costing of those elements; and
- develop our working assumptions.

43. The results of our review have been used to guide our suggested changes to the input assumptions. A summary of the salient points has been included below, with further information provided in Appendix C.

44. We understand that AEMC are aware of these issues, having acknowledged these issues in their recent supplementary report on pricing.[14]

Lines data

45. The model implements a stylised representation of the physical network in each region. From our limited scope review, we observe that:

- Line elements exist with zero rating;
- Line elements exist with zero length; and
- Some line ratings (Cts) of 999 MW and 9,876 MW at multiple voltages are significantly higher ratings than expected.

46. We also note that the upper and lower limits used for the size classifications of L, M and H (referred to as breakpoints) are generally consistent for similar ratings.

Transformer data

47. The model implements a stylised representation of the physical network in each region. From our limited scope review, we observe that:

- The breakpoints for size classification are generally consistent for similar ratings;
- Transformer elements exist with a rating of zero; and
- A transformer rating (Cts) of 9,876 MW at 275kV is significantly higher than expected.

[14] Australian Energy Market Commission 2014, *Supplementary report: Pricing, Optional Firm Access, Design and Testing*, p75, http://www.aemc.gov.au/Markets-Reviews-Advice/Optional-Firm-Access,-Design-and-Testing

3 Enhanced costing model

48. This section of the report provides the methodology, ratings and cost parameters used in the alternate costing model we propose. We include discussion of attributes and scale factors that we consider may materially influence the accuracy of the cost estimates.

3.1 Methodology

49. We have applied a building block method of developing cost parameters and an alternative costing model for lines and transformers.

50. The selected cost parameters are consistent with those typically applied to derive preliminary planning estimates for options analysis. The costing model is underpinned by a series of assumptions that reflect a reasonable estimate of the building block cost parameters, reference to industry practices, and other relevant industry sources.

51. We have included a number of scaling factors to apply to the building block unit costs to account for basic elements of line and transformer design that would normally be taken into account in deriving a preliminary cost estimate. These factors are discussed in detail in Section 4.

52. We do not explicitly include or discuss all of the detailed design parameters that would normally be required for a final cost estimate (ie. based on a detailed and optimised engineering design and tendered prices).[15]

[15] Such as the conductor size and configuration, specific tower and/or pole designs, and reactive compensation for dynamic stability.

3.1.1 Building block method

53. Application of a building block method to cost estimation as the starting point for preparing preliminary planning estimates is common industry practice.

54. The elements used in the building block method are shown in the table below, with cost parameters developed for each element. Each of the elements are combined in blocks of cost which are built up to form the cost estimate.

Table 1: Elements of the building block method

Asset	Cost element	Cost type
Line	Line	Variable
Line	Line easement	Variable
Line	Line terminations (at each end)	Fixed
Line	Reactive compensation	Fixed
Transformer	Transformer	Variable
Transformer	Transformer circuit (excluding transformer)	Fixed

55. The selection of building block elements are, wherever possible, consistent with the building blocks available from the AEMO transmission unit cost estimates[16] and verified through other industry sources to ensure consistency with available cost information.

56. In our experience, each TNSP maintains an estimating database for developing planning estimates based on its own requirements, and refines this as part of its own value assurance process to account for changing market and economic conditions. This often includes review of completed projects and using external assurance partners. Verification against these estimating databases, if feasible, would further improve the robustness of the unit cost assumptions.

3.1.2 Cost formula

57. We propose simple amendments to the basic cost formulae, which are currently linear functions of the unit cost parameter:

Line cost = Line length x Line lumpiness x Line unit cost

Transformer cost = Transformer lumpiness x Transformer unit cost

[16] Australian Energy Market Operator 2012, *100 per cent renewables study – electricity transmission cost assumptions*, Version 1.0, http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes

58. We propose introducing a fixed and variable component to the cost to account for non-scalable costs associated with integrating lines and transformers into the network model in response to an OFA requirement. We consider that the addition of fixed and variable cost elements within the building block method provides a pragmatic approach to improve the granularity and cost reflectivity of the costing assumptions.

Lines

59. In the case of lines, the fixed cost accounts for the line circuit costs.[17] The revised cost formula can be explained as:

Line cost = [Line fixed cost] + [Line length x Line lumpiness x Line variable unit cost]

Transformers

60. In the case of transformers, the fixed cost accounts for the transformer circuit[18] and is based on the voltage:

Transformer cost = [Transformer fixed cost] + [Transformer lumpiness x Transformer variable unit cost]

3.1.3 Assumptions

61. The following assumptions are applied:

- *Capital costs only* – Allocation of operating and maintenance costs has not been included. Development of a lifecycle cost may form part of future enhancements to the costing model;
- *Existing infrastructure* - All assets are connected into existing switchyard or substation sites, thus the costs only account for expansions to the existing infrastructure and not establishment of new substations/nodes;
- *Inclusion of moderate property costs* - Consistent with feasibility studies undertaken previously for AEMO and subsequent inclusion into its unit cost estimates relied upon in our work, moderate property costs have been included in the building block estimates;
- *Thermal ratings only* - Consideration of dynamic stability criteria has not been included (i.e. no plant to provide dynamic voltage support for long lines or remote generation has been included); and
- *No consideration of generation type* – there is no consideration of specific requirements for different types of generation technologies even though

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[17] Line circuit at each end of the line, comprising circuit breakers, reactive plant, protection and ancillary equipment costs

[18] Comprising circuit breakers, protection and ancillary equipment costs.

actual transmission costs may vary with the type (and location) of generation technologies employed.

3.2 Application of ratings

62. The selection of ratings are, wherever possible, consistent with the ratings from AEMO transmission unit cost estimates.[19] Where they have not been available or are incomplete, we have interpolated costs around typical asset ratings.

3.2.1 Line ratings

63. Line design ratings are influenced by a large number of parameters, as discussed earlier, and generally reflect the local planning conditions. Operating ratings are often significantly lower than design ratings due to operational limitations, staging, or other factors. Only design ratings have been considered.

64. We have adopted an approach that assumes a Low (L) rating is commensurate with small single circuit construction, a Medium (M) rating reflects a circuit construction with twice the L rating and a High (H) rating reflects a circuit construction with design changes to increase the rating above the M rating.

65. This approach is consistent with the building block approach undertaken for comparative studies in Europe[20] and Australia.[21] AEMC have confirmed that parameters in the input files relate to individual circuits and not lines, and that a stylised expansion is also based on these same circuit parameters.

66. We have determined typical line ratings for each size, consistent with single circuit construction and reviewed these for consistency against industry information and the existing model data supplied by AEMC.

67. The individual line ratings are determined by reference to the M rating. Based on experience, we consider that the L rating should be equal to 50% of the M rating, and the H rating is equal to 120% of the M rating.

3.2.2 Transformer ratings

68. We have adopted an approach that seeks alignment with the available ratings in the AEMO transmission unit cost estimates,[22] and where this was not available

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[19] Australian Energy Market Operator 2012, *100 per cent renewables study – electricity transmission cost assumptions*, Version 1.0, http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes

[20] ICF Consulting 2002, *Unit costs of constructing new transmission assets at 380kV in EU*, http://ec.europa.eu/energy/electricity/publications

[21] Australian Energy Market Operator 2012, *100 per cent renewables study – electricity transmission cost assumptions*, Version 1.0, http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes

[22] Australian Energy Market Operator 2012, *100 per cent renewables study – electricity transmission cost assumptions*, Version 1.0, http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes

we have, based on our experience, assumed building block size ratings consistent with typical values for the relevant operating voltage.

3.3 Transmission line cost

Overview

69. The design and estimation of transmission line costs is inherently complex. The final design is contingent on a large number of variables. The designer seeks to optimise the design and cost to deliver the required performance as the basis for the firm estimate.

70. We have sought to provide a set of what we consider to be reasonably typical assumptions, from which we can determine standard building block estimates, as discussed below.

Assumptions

71. Our default assumptions for the development of transmission line costs include:

Table 2: Default attribute assumptions

Attribute	Assumption
Short or long line length	Long. Length is greater than 20 kms
Route directness	Route is direct. The ratio of suspension to strain towers is approximately 90/10
Terrain	Terrain is flat with optimum tower spacing
Soil condition	Soil structure is good with the use of standard footing design
Built environment	Built environment is rural, low density, with optimum tower spacing
Technology	Overhead line construction

72. The influence of these attributes on the variable unit line cost is discussed further in section 4.

Operating voltage

73. The operating voltage of the asset has a significant impact on the design, rating and cost of the asset. We have applied the voltage classifications provided by AEMC.

Line length

74. The length of the transmission line has a significant impact on the cost of the asset, with the unit cost of shorter lines often being much higher than for longer lines.[23]

75. Greater economies of scale are often associated with very long line lengths. Optimisation methods are also commonly applied which may result in some downward adjustment to cost. Long lines may require additional reactive compensation. To determine the impact of these costs, a detailed design would need to be undertaken and therefore no further adjustment has been provided for line length in the base (building block) estimates as a simplifying assumption.

3.3.1 Line variable unit costs

Line rating

76. The selection of building block line ratings is discussed in section 3.2.1. The line costs corresponding with each rating have been determined from industry sources. We have adopted the AEMO transmission unit cost estimates where possible with review against other available industry cost estimates.[24]

77. The selection of the conductor is a significant determinant of the line rating, and therefore the variable unit cost.

78. The supply and installation cost of the conductor is approximately 30% of the total supply and installation costs for overhead lines.[25] We consider that the overhead line costs are likely to fall within a band of +/- 10% across the size ratings. Accordingly, the unit line costs vary from $0.36m/km for a low capacity 110kV transmission line to $1.21m/km for a high capacity 500kV transmission line.

Easement

79. Easement costs, like other property costs are highly variable. Easement costs are influenced by local planning conditions, environmental requirements, land use, local community needs, load density and other factors. We consider this is significant enough to consider including into the base variable unit line cost rate. The materiality however is not considered sufficient to further differentiate the cost through the use of factors.

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[23] Australian Energy Market Operator 2012, *100 per cent renewables study – electricity transmission cost assumptions*, Version 1.0, http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes

[24] Such as those included in Sinclair Knight Merz 2010, *Feasibility study estimates for transmission network extensions*, Version 2.1, http://www.aemo.com.au

[25] C Bayliss and B Hardy 2012, *Transmission and Distribution Electrical Engineering*, Fourth Edition, Newnes UK, Table 18.9

80. Easement costs are likely to fall within a band of 4 – 10% of the transmission line costs,[26] noting that in some regions they may be higher.[27]

81. We consider that applying a rate of 5% to the variable unit line cost for each line reflects a reasonable estimate and ensures an increasing cost is associated with the wider easement requirements of higher operating voltages. Accordingly, these costs vary from $0.02m per kilometre for a 132kV line to $0.06m for a 500kV line.

3.3.2 Fixed lines costs

82. In addition to the transmission line, major costs are often associated with the connection of the transmission line into the existing transmission network. These costs are not variable with line length, and are therefore considered to be fixed costs components, as identified in Figure 1 and Table 1. They include the costs associated with line terminations, reactive compensation and any changes to the existing substation.

83. Our review of the AEMO transmission unit cost estimates[28] confirm that these additional costs can be 20% to 30% of the cost of the transmission line.[29]

84. We consider it important to include these costs in the stylised model. The costs of the associated plant are influenced by the operating voltage and function of the plant.

85. Indicative transmission augmentation costs were documented by AEMO in a separate report[30] for the line circuit (referred to as switchbays),[31] major plant items (i.e. reactive compensation) and substation establishment. We have reviewed these costs:

- *For line terminations* – we have applied a single circuit connection to an existing terminal station using a 1 ½ breaker arrangement (known as 3 breaker diameter) with 2 circuit breakers installed.[32] We have included the

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[26] Sinclair Knight Merz, *Pre-feasibility Estimates for NEMLink*, Version 2.0, page 9, http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2010-NTNDP/2010-NTNDP-Data-and-Supporting-Information/

[27] For example, if there is significant property resumption and vegetation offset requirements.

[28] Australian Energy Market Operator 2012, *100 per cent renewables study – electricity transmission cost assumptions*, Version 1.0, http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes

[29] Australian Energy Market Operator 2011, *NTNDP Chapter 8 - Gas and electricity transmission comparative case study*, http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2011-National-Transmission-Network-Development-Plan/Report-Chapters

[30] Australian Energy Market Operator 2011, *Indicative transmission augmentation costs in Victoria*, Version 1.0, http://www.aemo.com.au

[31] AEMO's estimates include design, procurement, installation, project management, testing and commissioning costs for the relevant electrical plant, as well as foundations/civil costs associated with the footprint area of the bay.

[32] We have taken this approach to reflect actual costs involved in augmenting a transmission terminal station to accommodate a new line circuit in which a new bus section circuit breaker and the new line

cost of a new 1 ½ breaker line circuit at each end of the transmission line. Where costs have not been available for specific operating voltage, we have applied our own experience.

- *For reactive compensation* – we have applied a sliding scale of costs based on industry information differentiated by operating voltage. This ranges from $2m for reactive compensation on 110kV and 132kV transmission lines to $5m for a 500kV transmission line.

- *For substation establishment* – we have assumed that the transmission line will be connected into an existing substation, and that the substation infrastructure (i.e. land, earthworks, roads, buildings and secondary systems) are already in place for that line circuit. We have not included any incremental costs associated with the substation establishment. We consider that terminal substations are often established with sufficient spare site area and essential infrastructure for future connections and to include the costs of establishing a substation would present a significant over-estimation bias.

86. Consideration of larger asset expenditure such as series capacitors or static var compensators (SVC) are case specific and determined by more detailed analysis of the dynamic operation of the transmission network. For this reason, costs associated with these elements are not considered to form part of a high level planning estimate and have been excluded from this costing model.

3.4 Transformer cost

3.4.1 Variable unit costs

87. Power transformers used on the transmission network are typically specified by the customer, based on their individual system performance requirements local design, operating and maintenance requirements.

88. Cost are typically proportional to the size of the transformer, and in the costing model are based on an approximation of data sourced from the AEMO transmission unit cost estimates.[33]

3.4.2 Fixed costs

89. Integrating a transformer into the transmission network also requires a transformer circuit and any changes to the existing substation.

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circuit breaker must be installed (along with isolators and other primary and secondary plant and equipment).

[33] Australian Energy Market Operator 2012, *100 per cent renewables study – electricity transmission cost assumptions*, Version 1.0, http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes

90. We consider that the indicative transmission augmentation costs that were documented by AEMO (as detailed above) for the transformer circuit and substation establishment costs can be also applied to transformers.

91. Indicative transmission augmentation costs were documented by AEMO in a separate report[34] for the transformer circuits (referred to as switchbays)[35] and substation establishment.[36] We have reviewed these costs and determined that:

- *For transformer circuits* – we have applied a single circuit connection to an existing terminal station using a 1 ½ breaker arrangement (known as 3 breaker diameter) with 2 circuit breakers installed. Where costs have not been available for specific operating voltage, we have applied our own experience.

- *For substation establishment* – we have not included any incremental costs associated with the substation establishment, rather, we have assumed that the transformer will be installed into an existing substation, and that the substation infrastructure (i.e. land, earthworks, roads, buildings and secondary systems) are already in place for that line circuit. We consider that terminal substations are often established with sufficient spare site area and essential infrastructure for future connections and to include the costs of establishing a substation would present a significant over-estimation bias.

[34] Australian Energy Market Operator 2011, *Indicative transmission augmentation costs in Victoria*, Version 1.0, http://www.aemo.com.au

[35] AEMO's estimates include design, procurement, installation, project management, testing and commissioning costs for the relevant electrical plant, as well as foundations/civil costs associated with the footprint area of the bay.

[36] AEMO refer only to estimates based on outdoor switchyards – fully indoor or hybrid indoor/outdoor switchyards would be significantly more expensive.

4 Attributes and factors

92. This section details the approach and selection of attributes and scale factors that can be applied to the cost parameters to increase the granularity of asset costings to be more reflective of the cost of augmenting the transmission network than relying solely on the building block costs.

4.1 Overview

93. We have reviewed methods to improve the current data set and have determined that the current three level categorisation of assets, being L, M and H is sufficient categorisation for the purposes of AEMC prototype model.

94. We have considered expanding the set of elements beyond the use of lines and transformers, however, in our view any additional granularity achieved would be offset by the additional model complexity. We consider that the inclusion of additional fixed cost components (ie. line terminations and transformer circuits) within the building blocks of each of the line and transformer elements is the most pragmatic approach to take at this stage.

95. We consider that attributes that may materially influence the cost of a transmission line should be included. These are discussed in the following sections along with an assessment of the ability to define the likely impact of these attributes on the transmission line cost.

96. We also propose the use of cost scale factors within each of the proposed attributes to account for the variation in transmission line design and construction costs across the different regions in the NEM. The scale factors apply to each attribute and therefore to the overall variable transmission line cost.

97. The cost scale factors provide a coarse measure of adjustment to the total transmission line cost, and therefore should only be applied where they are representative of the total length of the transmission line.

98. We have determined that the combined effect of the cost scale factors varies from 1 to 8 times the 'default' transmission line unit cost to account for the impact of the cost attributes. We recommend calibration of the proposed cost scale factors in association with the TNSP businesses.

99. We have not proposed a set of attributes and cost factors to be applied to transformer building block estimates for three reasons:

(i) We have assumed that the AEMC (and other sources of cost estimates that we have drawn upon) include the particular design features that cost-effectively lead to the nominated ratings or sizes;

(ii) The cost of transformers is influenced by a number of design attributes and their variability makes it difficult (and potentially unhelpful) to characterise them into a set of attributes and cost factors that can be applied to a range of transformer sizes; and

(iii) Much higher transformer costs are often associated with unique or specialist Extra High Voltage (EHV) transformer designs (ie. ≥330kV), but these are typically not included in preliminary cost estimates (rather they are determined as part of the detailed design estimate).

4.2 Improving the costing of transmission lines

4.2.1 Approach

100. Our research has identified that a range of transmission line costs may be expected, and that based on the attribute assumptions, an estimate within that range may be selected for the planning estimates. For example, the cost of a 500kV transmission line may vary from between $1.4m and $3.5m per kilometre.[37]

101. We propose that scale factors are proposed for variations within each of the attributes listed in Table 2. These cost factors are applied to the line variable unit cost at each operating voltage, as a reasonable indicator of the range in line variable unit costs that may be expected.

102. We consider that, with the proper precautions (discussed in section 4.2.2), the scale factors can be multiplied together and applied as a single overall cost scale factor to the line variable cost.

4.2.2 Limitations of cost scale factors

103. Importantly, the selection of attributes and associated cost scale factors should be carefully considered as being representative of the total or near-total line length, and not isolated to small sections so as to avoid an over-estimate of the

[37] Sinclair Knight Merz, *Pre-feasibility Estimates for NEMLink*, Version 2.0, page 13, http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2010-NTNDP/2010-NTNDP-Data-and-Supporting-Information/

line costs. Furthermore, there are combinations of attributes that are less likely to occur together, and therefore these will not have a simple multiplicative affect.

104. Our costing model includes logic to account for these affects and limit the potential bias:

- *For transformer elements* – the overall scale factor is equal to 1, as the scale factors do not apply;
- *For short lines* – the built environment is the only other cost scale factor that impacts the variable cost. All other cost scale factors are considered to already be accounted for; and
- *For underground cable technology* – the proposed cost scale factor is sufficient to reflect the cost relative to overhead construction without any other cost scale factors.

4.2.3 Summary of attributes

Design attributes

105. A transmission line design has a large number of design attributes based on the performance requirements for the asset that are considered in the engineering design phase of the transmission line. These are described well in publically available reports.[38]

106. Other than those attributes described below, the impact of design attributes on the transmission line cost are considered to be included within the preliminary estimate error tolerance of the line unit cost rate.

Short lines

107. The labour component can be heavily influenced in shorter lines where the efficiencies associated with a long transmission line are not available. We consider that this can have a sufficiently large distortional effect on the cost of shorter transmission lines, as noted by AEMO's modelling,[39] where a cost multiplication factor of 2.0 has been used for line lengths less than or equal to 20km.

108. For the purposes of this costing model, we consider that the inclusion of a short lines scale factor in accordance with the table below to be prudent.

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[38] Power Systems Consultants Australia 2009, *Network extensions to remote areas part 1 – planning considerations*, http://www.aemo.com.au

[39] Australian Energy Market Operator 2012, *100 per cent renewables study – electricity transmission cost assumptions*, Version 1.0, http://www.environment.gov.au/climate-change/publications/aemo-modelling-outcomes

Table 3: Short lines scale factors

Short lines

Attribute	Cost scale factor	Description
L	1	Long - line length greater than 20km, cost mulitplier is equal to 1
S	2	Short - line length less than or equal to 20km, cost mulitplier is equal to 2

Route directness

109. Typically new major generation or load centres are located remotely from the existing transmission network. The most efficient route may be required to traverse a range of land uses which may introduce constraints which have impacts to the design and construction and therefore cost of the line (eg. height restrictions (for aircraft), clearances for farm machinery, route selection to prevent damage to environmental or heritage sensitive areas).

110. These issues are difficult to ascertain at a global level, and are typically considerations in the individual route selection. A significant influence on the structure design is the nominated path or route of the transmission line. The selection of tower / structure design is determined by the function of the tower to support the change in direction of the transmission line. This includes: suspension structures, heavy suspension structures (designed for larger angles); inline strain structures, strain structures (designed for major line angle/deviations) and termination structures.

111. Each structure type will have a number of corresponding design elements to be considered, each with a corresponding influence on cost. A significant determinant of cost is the ratio of strain versus suspension structures, as the cost of a strain structure is significantly higher than a suspension structure.

112. Typically the ratio of angle or strain structures to suspension structures is in the order of 10-20% (ie. a relatively direct line route).[40] Where this is exceeded, the line cost can increase by 20% or more.

113. For the purposes of this costing model, we consider that the inclusion of a route directness scale factor in accordance with the table below to be reasonable.

Table 4: Route directness scale factors

Route directness

Attribute	Cost scale factor	Description
D	1	Direct - normal proportion of angle / tension structures, typically 10-20% of all structures
I	1.2	Indirect - increased proportion of change in angle, typically greater than 20%

[40] Assumptions used for planning estimates for AEMO were typically 10%, whereas other sources ranged up to 20%.

Location and terrain

114. Additional issues such as the terrain and accessibility of the land can have a more significant impact on the cost (eg. construction on hilly or mountainous land may require additional and/or taller (more expensive) towers and specific tower placement driving increasing costs when compared with flat land. Access and mobilisation costs are also significantly increased.

115. In a review of the actual costs associated with transmission lines in European countries[41] the study assumed a cost premium for terrain of up to 50%.

116. Based on a high level assessment of the land use and terrain of the existing network, we consider that the addition of a terrain scale factor in accordance with the table below to be reasonable.

Table 5: Terrain scale factors

Terrain

Attribute	Cost scale factor	Description
R	1	Rural, flat conditions
U	1.2	Undulating conditions
H	1.4	Hilly conditions or difficult access

Soil conditions

117. The cost associated with the design and construction of the foundations for transmission structures is often a significant part of the overall transmission line cost. Whilst TNSPs seek to standardise the parameters of these designs, the footing designs are influenced by local soil conditions.

118. The adequacy of the soil determines the design and materials for the footings and also the structure. Working in remote locations and requiring large footings can have a significant impact on the final cost. Equally, a significant amount of rock (requiring specialist equipment to remove) will also have a material impact on the line cost.

119. For the purposes of this costing model, we consider that the inclusion of a soil conditions scale factor in accordance with the table below to be prudent.

Table 6: Soil conditions scale factors

Soil conditions

Attribute	Cost scale factor	Description
G	1	Average soil condition
A	1.2	Poor soil strength and structure
P	1.4	Poor soil strength and structure with increased risk of subsidence or heavy rock

[41] ICF Consulting 2002, *Unit costs of constructing new transmission assets at 380kV in EU*, http://ec.europa.eu/energy/electricity/publications

Built environment

120. The built environment can have a significant impact on the cost of the asset. For example, the size of towers may need to be increased or spacing of towers reduced to account for higher density areas when compared with a rural environment.

121. The resulting costs can vary considerably, and can reasonably be expected to correlate with load densities.

122. For the purposes of this costing model, we consider that the inclusion of a density of built environment scale factor in accordance with the table below to be prudent.

Table 7: Built environment scale factors

Built environment

Attribute	Cost scale factor	Description
R	1	Average density, typical of rural / outer urban areas
U	1.5	Increased density typical of inner urban / built-up areas

Technology

123. An underground cable may be used in place of an overhead transmission line. An underground cable costs from 5 to 10 times that of a transmission line, with the typical range 6-8 times.

124. We recommend adopting the higher end of that range for this study and not including the impact of other relevant scale factors.

125. Therefore, for the purposes of this costing model, we consider that the inclusion of a technology scale factor in accordance with the table below to be prudent.

Table 8: Technology scale factor

Technology

Attribute	Cost scale factor	Description
O	1	Overhead - normal overhead line design and construction
U	8	Underground - cable design and construction

4.3 Response to issues identified by AEMC

126. AEMC identified some potential significant issues associated with improving or expanding the current data set that must be addressed by any proposed changes. We have addressed these issues in our advice, as discussed below.

Expanding the number of variables

127. In the request for quotation, AEMC noted that:

> *'Expanding the number of variables has a multiplication effect on the number of asset categories in the linetypes file, and hence the number of unique*

costs and lumpiness assumptions that the consultant would be required provide.'

128. The selection of a number of material attributes and application of cost scale factors into a single overall cost scale factor avoids the need to expand the number of asset categories or variables within the linetypes file. We consider that the application of scale factors provides a pragmatic approach that does not impose significant additional complexity on the model.

Changes to the asset categories

129. In the request for quotation, AEMC noted that:

'Any changes to the asset categories would need to be reflected in the aemc_lines files.'

130. The addition of attributes and cost scale factors represents a change to the asset information held in the aemc_lines files for each region. We consider that the implementation of this change is not complex. Further we consider the implementation of this change can commence by applying a default cost scale factor corresponding with unity as a means to transition to full functionality.

131. We consider that the addition of attributes and cost factors will impact a moderate number of transmission lines. The information required to populate the attributes and scale factors within the stylised design should be readily available from the respective TNSPs.

5 Application of the costing model

5.1 Summary observations

132. The output of the costing model, described below, indicates that a systematic bias to under-estimation was evident in the original costing.

133. The outputs do not include the impact of the scale factors discussed in section 4, and when applied may indicate that a potentially higher systemic bias was present.

5.2 Transmission lines

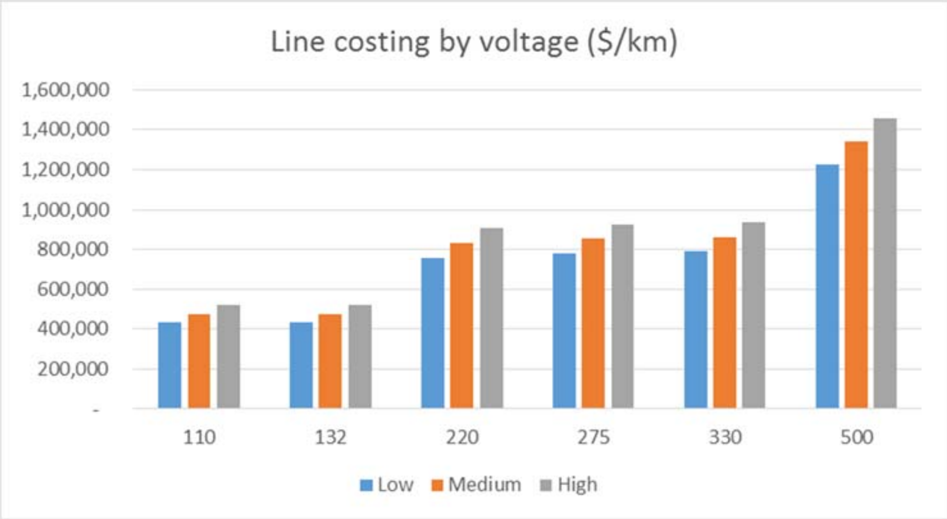
134. The output of the costing model for transmission lines shows the total unit line cost increasing with the operating voltage. The cost is also differentiated by the size of the line – Low, Medium and High as shown in the figure below.

135. The costing model has assumed the same building block costs for line terminations and unit costs for:

- 110kV and 132kV transmission lines; and
- 220, 275 and 330kv transmission lines.

136. To determine the total unit cost per kilometre, an approximation of the fixed cost component was calculated by dividing the fixed cost by a line length of 100km for each line.

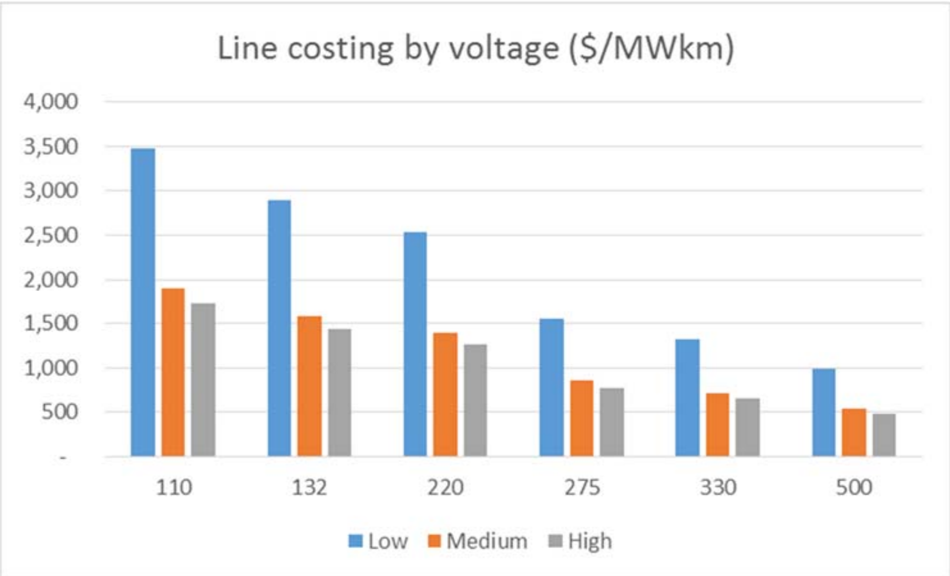
Figure 2: Output of line costing results, $/km



Source: Attachment A: Costing Model, Lines – Costing model (Total unit cost)

137. The figure below shows the output of the costing model when converted into $ per MW kilometre, being the units required by the PFAP model.

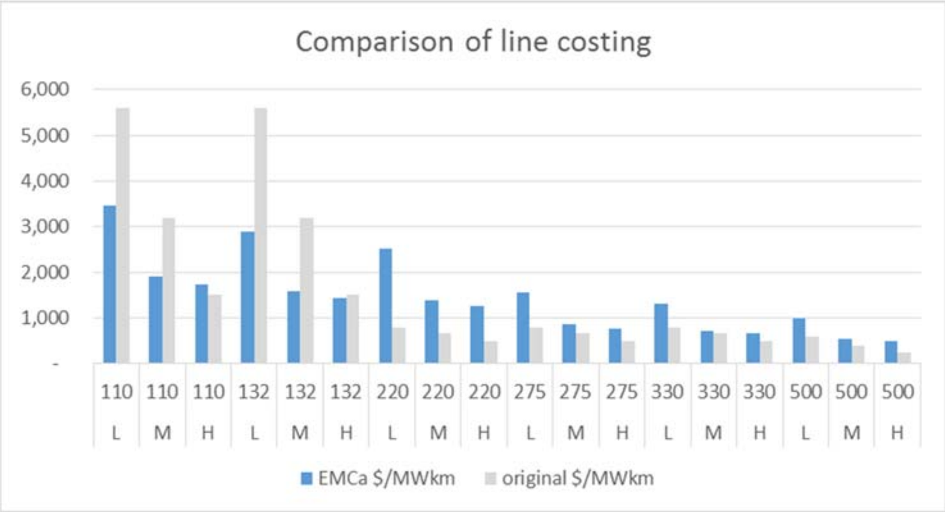
Figure 3: Output of line costing results, $/MWkm



Source: Attachment A: Costing Model, Lines – Costing model (Total unit cost)

138. A comparison of the original costing values to the output of the costing model shows changes of between 50% and 325%, with reductions in cost parameters for some sizes at 110 and 132kV.

Figure 4: Comparison of line costing, $/MWkm



Source: Attachment A: Costing Model, Lines – Costing model (Total unit cost)

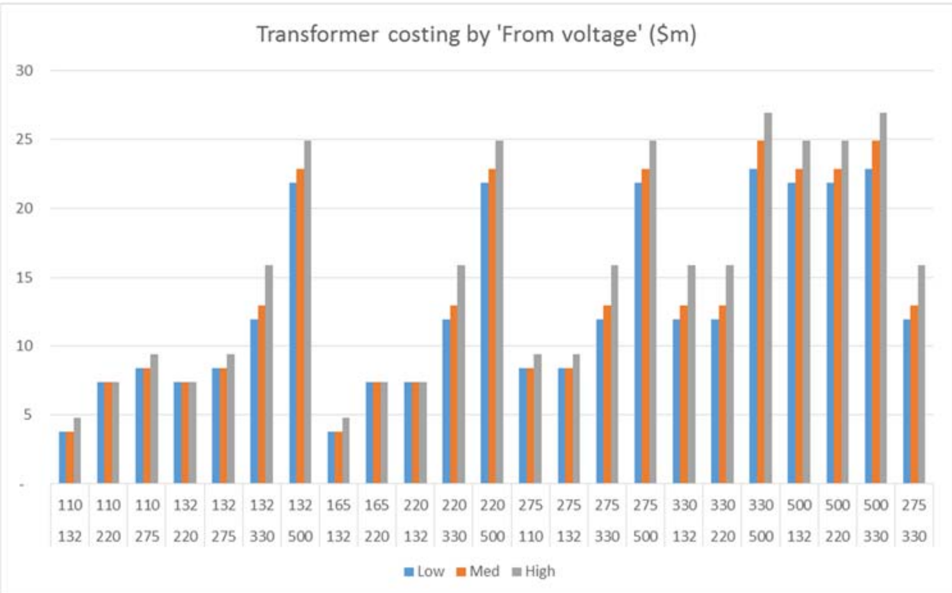
5.3 Transformers

139. The output of the costing model for transformers shows the total transformer cost increasing with the highest operating voltage of the transformer. The cost is also differentiated by the size of the line – Low, Medium and High as shown in the figure below

140. The costing model has assumed the same building block costs for transformer circuits, where the highest operating voltage of the transformer is:

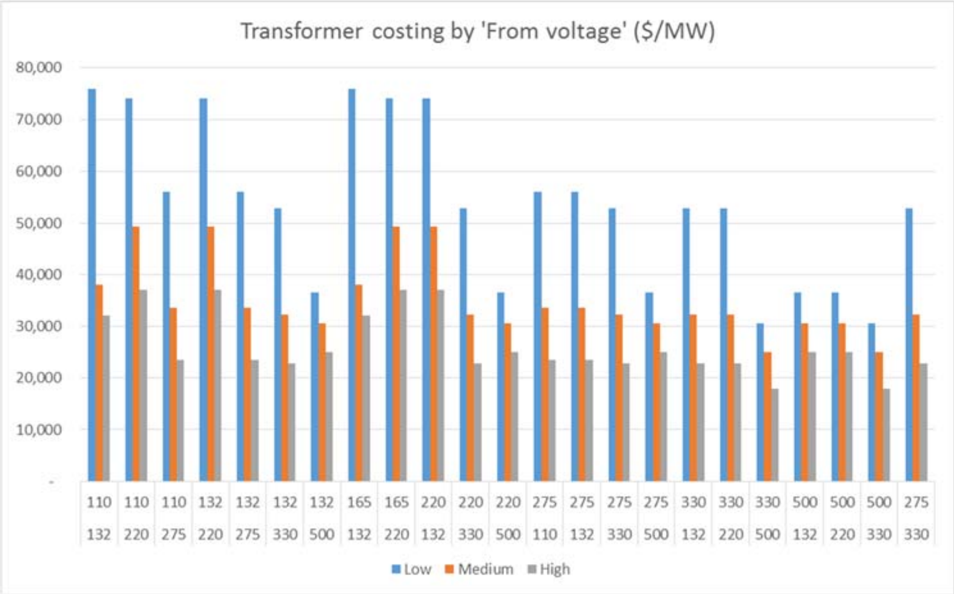
- 110kV or 132kV; and
- 220, 275 or 330kV.

Figure 5: Output transformer costing results, $m



Source: Attachment A: Costing Model, Transformer – Costing model (Total unit cost)

Figure 6: Output transformer costing results, $/MW

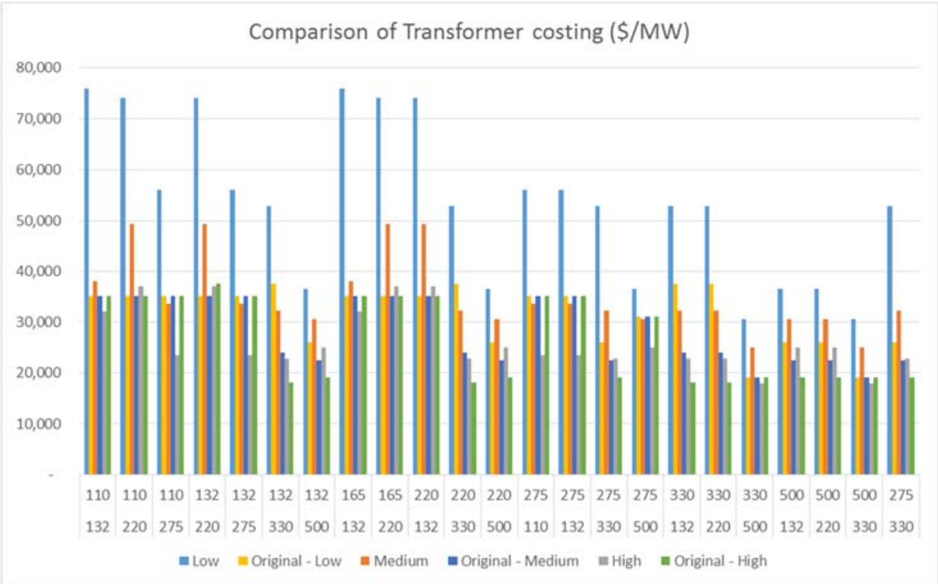


Source: Attachment A: Costing Model, Transformer – Costing model (Total unit cost)

141. A comparison of the original costing values to the output of the costing model shows greater differentiation of the transformer costs. The costs associated with 'Low' size transformers and some 'Medium' size transformers is much higher as shown in the figure below.

142. The costing model has assumed that the transformer cost at lower operating voltages is not influenced by size in the same way as for higher operating voltages.

Figure 7: Comparison of the transformer costing results, $/MW



Source: Attachment A: Costing Model, Transformer – Costing model (Total unit cost)

6 Implications and conclusions

143. This section summarises the improvements and implications of the alternate costing model and application of attributes on the current PFAP model.

6.1 Summary

144. The alternate costing model uses both fixed and variable costs for lines and transformers. The current prototype pricing model does not accept a fixed cost component, and will therefore require changes to the cost formulae.

145. We have therefore presented our results for both:

- Fixed and variable cost components to accommodate a future change in the costing formulae, and
- A fully variable cost component only (Total unit cost).

146. For completeness we have included two input files.

6.1.1 Transmission lines

147. We propose a change to the cost formula that adds a fixed cost component to the cost of a transmission line:

Line cost = [Line fixed cost] + [line length x line lumpiness x Line variable unit cost x overall scale factor]

148. If the AEMC consider that changes to the cost formula in the model are not required, AEMC may consider a further simplification, by approximating the fixed cost as being a function of a standard line length (i.e. 100km) and applying this as a fully variable unit cost.

149. We note however that in making this further simplification, a potential over estimation bias may be present as the cost scale factors are intended to be applied to the variable unit costs only. The attributes and cost scale factors will need to be further adjusted in this case.

6.1.2 Transformers

150. We propose a change to the cost formula that adds a fixed cost component to the cost of a transformer:

Transformer cost = [Transformer fixed cost] + [Transformer lumpiness x Transformer variable unit cost]

151. If the AEMC consider that changes to the model are not required, AEMC may consider a further simplification, by approximating the fixed cost as a function of the transformer rating.

6.2 Application of attributes and cost scale factors

152. To improve the accuracy of the variable and fixed cost parameters, we have also incorporated a number of scale factors to the line variable unit cost.

153. The line scale factors would also need to be added to an enhancement of the model. This requires population of the NEM asset files with the necessary attribute values for each line element. Scale factors can then be 'looked up' and multiplied together using simple logic to determine an overall scale factor that is then applied as shown in the formula in section 6.1.1 above.

154. We have included these factors into an updated lines file for Victoria to demonstrate the combined effect of the attribute cost factors. We have allocated the factors corresponding with a scale of unity, such that there is no effect of the scale factors to the cost formula once initially implemented, but such that attribute values will have the desired effect on the costings once entered.

155. We envisage that the cost formula would be simply amended to incorporate the inclusion of the overall scale factor. A bias to under-estimate costings is likely to persist until this is in place.

156. For the reasons discussed earlier, we have not proposed scale factors for use with transformer variable unit costs.

6.3 Addressing previous findings

157. We have assessed our advice against the previous findings of our earlier report and have identified what we consider to have been addressed and what is not covered (in scope) at this time.

Two material network elements

158. Our earlier advice to AEMC stated that:

> *'The assumption that there are only two material network elements – lines and transformers – appears to ignore the significant costs of substation bays. Additional lines will need termination and additional transformers require switchyard bays with associated switchgear, protection systems and the like. These may add a significant multiple to the costs currently represented only by transformers. ……. The present shortcomings could be relatively easily rectified – for example through modest enhancements to the costing of augmentations, and input of more realistic unit cost assumptions.'*

159. We consider that this statement has been addressed in our advice, with the alternate costing model provided.

Unit costing anomalies

160. Our earlier advice to AEMC stated that:

> *'While we have not comprehensively reviewed unit costs assumptions, we observe what appear to be some significant anomalies.'*

161. We consider that this statement has been addressed in our advice, with the alternate costing model provided inclusive of the revised assumptions.

Infeasible ratings

162. Our earlier advice to AEMC stated that:

> *'Some assets seem to have infeasible ratings – for example, 200MW transfer capacity for a 220kV line is less than half what we would expect, and a lumpiness of only 100MW for a 275kV line would seem to be an error.'*

163. We consider that this statement has been addressed in our advice, with the alternate costing model provided inclusive of the revised assumptions.

Augmentation modelling

164. Our earlier advice to AEMC also stated that:

> *'We consider that there are ways in which it should be possible to improve on the augmentation modelling, such that it is less likely to be biased towards over-estimation by assuming inefficient replication of existing elements when lower-cost options may be readily identifiable to an experienced planning engineer. This would require design scoping to determine how such improvements to the model could be made.'*

165. Whilst we were not asked to provide advice on this issue, we consider that the bias resulting from use of higher cost options may be addressed by i) the use of additional cost scale factors to account for more efficient or different combinations of assets, or ii) modifying the model such as through limiting combinations and applying some simple planning 'rules' in place of multiple replication of existing elements.

Maintenance costs

166. Further to our earlier advice, we understand that the AEMC are considering whether and how to address the treatment of maintenance costs. Our analysis has not included operating or maintenance costs in the costing model at this time.

6.4 Concluding remarks

167. We have nominated a number of enhancements to the input cost assumptions to further improve the cost reflectivity of the asset costings within the prototype pricing model. We recognise that the model is a stylised, simplified model, and that the costs identified with this prototype model are to assist AEMC continue to develop the model.

Greater alignment with the AEMO unit cost estimates

168. We understand that AEMO has been developing a comprehensive guide to transmission unit cost estimates to assist its own planning purposes. AEMC may consider aligning its own data sources with AEMO.

169. We have sought to align, wherever possible, with the publically available information based on the AEMO transmission unit cost estimates.

170. The scope and timing of our work did not allow for the development of information sharing arrangements between AEMC and AEMO to make use of this information in its entirety.

Verification against actual TNSP cost data

171. We consider that as a part of the ongoing development of the model, consideration be given to testing the outputs and assumptions against i) the TNSP's own cost estimating and planning estimate systems and ii) review of planning level estimates for forecast and completed transmission projects.

Appendix A – Updated linetypes input file – fixed plus variable unit costs

type	from_voltage	to_voltage	size	lumpiness	cost(variable)	cost (fixed)
L	132	132	L	150	2520	5600000
L	132	132	M	300	1400	5600000
L	132	132	H	360	1283	5600000
L	110	110	L	125	3024	5600000
L	110	110	M	250	1680	5600000
L	110	110	H	300	1540	5600000
L	220	220	L	300	2205	9800000
L	220	220	M	600	1225	9800000
L	220	220	H	720	1123	9800000
L	275	275	L	500	1323	11800000
L	275	275	M	1000	735	11800000
L	275	275	H	1200	674	11800000
L	330	330	L	600	1103	12800000
L	330	330	M	1200	613	12800000
L	330	330	H	1440	561	12800000
L	500	500	L	1250	832	18800000
L	500	500	M	2500	462	18800000
L	500	500	H	3000	424	18800000
T	110	132	L	50	40000	1800000
T	110	132	M	100	20000	1800000
T	110	132	H	150	20000	1800000
T	110	220	L	100	50000	2400000
T	110	220	M	150	33333	2400000
T	110	220	H	200	25000	2400000
T	110	275	L	150	33333	3400000
T	110	275	M	250	20000	3400000
T	110	275	H	400	15000	3400000
T	132	220	L	100	50000	2400000
T	132	220	M	150	33333	2400000
T	132	220	H	200	25000	2400000
T	132	275	L	150	33333	3400000
T	132	275	M	250	20000	3400000
T	132	275	H	400	15000	3400000
T	132	330	L	225	35556	3900000
T	132	330	M	400	22500	3900000
T	132	330	H	700	17143	3900000
T	132	500	L	600	25000	6900000
T	132	500	M	750	21333	6900000
T	132	500	H	1000	18000	6900000
T	165	132	L	50	40000	1800000
T	165	132	M	100	20000	1800000
T	165	132	H	150	20000	1800000
T	165	220	L	100	50000	2400000
T	165	220	M	150	33333	2400000
T	165	220	H	200	25000	2400000
T	220	132	L	100	50000	2400000
T	220	132	M	150	33333	2400000
T	220	132	H	200	25000	2400000
T	220	330	L	225	35556	3900000
T	220	330	M	400	22500	3900000

T	220	330	H	700	17143	3900000
T	220	500	L	600	25000	6900000
T	220	500	M	750	21333	6900000
T	220	500	H	1000	18000	6900000
T	275	110	L	150	33333	3400000
T	275	110	M	250	20000	3400000
T	275	110	H	400	15000	3400000
T	275	132	L	150	33333	3400000
T	275	132	M	250	20000	3400000
T	275	132	H	400	15000	3400000
T	275	330	L	225	35556	3900000
T	275	330	M	400	22500	3900000
T	275	330	H	700	17143	3900000
T	275	500	L	600	25000	6900000
T	275	500	M	750	21333	6900000
T	275	500	H	1000	18000	6900000
T	330	132	L	225	35556	3900000
T	330	132	M	400	22500	3900000
T	330	132	H	700	17143	3900000
T	330	220	L	225	35556	3900000
T	330	220	M	400	22500	3900000
T	330	220	H	700	17143	3900000
T	330	500	L	750	21333	6900000
T	330	500	M	1000	18000	6900000
T	330	500	H	1500	13333	6900000
T	500	132	L	600	25000	6900000
T	500	132	M	750	21333	6900000
T	500	132	H	1000	18000	6900000
T	500	220	L	600	25000	6900000
T	500	220	M	750	21333	6900000
T	500	220	H	1000	18000	6900000
T	500	330	L	750	21333	6900000
T	500	330	M	1000	18000	6900000
T	500	330	H	1500	13333	6900000
T	330	275	L	225	35556	3900000
T	330	275	M	400	22500	3900000
T	330	275	H	700	17143	3900000

Appendix B – Updated linetypes input file – variable unit costs only

type	from_voltage	to_voltage	size	lumpiness	cost
L	132	132	L	150	2893
L	132	132	M	300	1587
L	132	132	H	360	1439
L	110	110	L	125	3472
L	110	110	M	250	1904
L	110	110	H	300	1727
L	220	220	L	300	2532
L	220	220	M	600	1388
L	220	220	H	720	1259
L	275	275	L	500	1559
L	275	275	M	1000	853
L	275	275	H	1200	772
L	330	330	L	600	1316
L	330	330	M	1200	719
L	330	330	H	1440	650
L	500	500	L	1250	982
L	500	500	M	2500	537
L	500	500	H	3000	486
T	110	132	L	50	76000
T	110	132	M	100	38000
T	110	132	H	150	32000
T	110	220	L	100	74000
T	110	220	M	150	49333
T	110	220	H	200	37000
T	110	275	L	150	56000
T	110	275	M	250	33600
T	110	275	H	400	23500
T	132	220	L	100	74000
T	132	220	M	150	49333
T	132	220	H	200	37000
T	132	275	L	150	56000
T	132	275	M	250	33600
T	132	275	H	400	23500
T	132	330	L	225	52889
T	132	330	M	400	32250
T	132	330	H	700	22714
T	132	500	L	600	36500
T	132	500	M	750	30533
T	132	500	H	1000	24900
T	165	132	L	50	76000
T	165	132	M	100	38000
T	165	132	H	150	32000
T	165	220	L	100	74000
T	165	220	M	150	49333
T	165	220	H	200	37000
T	220	132	L	100	74000
T	220	132	M	150	49333
T	220	132	H	200	37000
T	220	330	L	225	52889
T	220	330	M	400	32250

T	220	330	H	700	22714
T	220	500	L	600	36500
T	220	500	M	750	30533
T	220	500	H	1000	24900
T	275	110	L	150	56000
T	275	110	M	250	33600
T	275	110	H	400	23500
T	275	132	L	150	56000
T	275	132	M	250	33600
T	275	132	H	400	23500
T	275	330	L	225	52889
T	275	330	M	400	32250
T	275	330	H	700	22714
T	275	500	L	600	36500
T	275	500	M	750	30533
T	275	500	H	1000	24900
T	330	132	L	225	52889
T	330	132	M	400	32250
T	330	132	H	700	22714
T	330	220	L	225	52889
T	330	220	M	400	32250
T	330	220	H	700	22714
T	330	500	L	750	30533
T	330	500	M	1000	24900
T	330	500	H	1500	17933
T	500	132	L	600	36500
T	500	132	M	750	30533
T	500	132	H	1000	24900
T	500	220	L	600	36500
T	500	220	M	750	30533
T	500	220	H	1000	24900
T	500	330	L	750	30533
T	500	330	M	1000	24900
T	500	330	H	1500	17933
T	330	275	L	225	52889
T	330	275	M	400	32250
T	330	275	H	700	22714

Appendix C – Review of existing data

Existing lines data

172. The results of our review of existing lines data are provided in the table below.

Table 9: Existing lines data (October 2014 version of the model)

Voltage	Estimated breakpoints	Observations
110kV	100 and 250 MW	Continuous circuit rating (Cts) of 999 MW and 9,876 MW appears to be an error.
132kV	150 and 300 MW	Continuous circuit rating (Cts) of 9,876 MW appears to be an error.
220kV	400 and 600 MW	Continuous circuit rating (Cts) of 999 MW appears to be an error.
275kV	500 and 1,000 MW	Continuous circuit rating (Cts) of 9,876 MW appears to be an error.
330kV	800 and 1,125 MW	Breakpoints across NSW and QLD were not consistent.
		Continuous circuit rating (Cts) of 9,876 MW appears to be an error.
500kV	3,000 MW	No comment.

Source: EMCa analysis

Existing transformers data

173. The results of our review of the existing transformer data are provided in the table below.

Table 10: Existing transformer data (October 2014 version of the model)

Voltage	Observations
110kV	No comment.
132kV	132/220kV 120MVA transformer size in VIC considered to be of 'High' size, whereas 132/275kV 200MVA transformer in three other states is considered to be of 'Low' size Transformers in QLD and VIC with zero rating appears to be an error.
220kV	220/500kV transformer in VIC with zero rating appears to be an error.
275kV	275/132kV transformer in QLD with 9,876 MW rating appears to be an error.
330kV	No comment.
500kV	500/220kV transformer in VIC with zero rating appears to be an error.

Source: EMCa analysis

Appendix D – Bibliography

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Attachment A – Costing model