Final decision

TransGrid transmission determination 2009–10 to 2013–14

28 April 2009

AUSTRALIAN ENERGY REGULATOR

Australian Energy Regulator
360 Elizabeth Street
Melbourne Central
Melbourne Vic 3000

GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457
Email: AERInquiry@aer.gov.au
Web: www.aer.gov.au

Contents

Shortened forms iv

Overview v

Summary viii

1 Introduction 1

1.1 Background 1
1.2 AER draft decision 1
1.3 Revised revenue proposal 2
1.4 Review process 4
1.5 Structure of final decision 5

2 Opening asset base 6

2.1 Introduction 6
2.2 AER draft decision 6
2.3 Revised revenue proposal 7
2.4 Issues and AER considerations 7
2.5 AER conclusion 9

3 Forecast capital expenditure 11

3.1 Introduction 11
3.2 AER draft decision 11
3.3 Revised revenue proposal 12
3.4 Submissions 13
3.5 Consultant review 13
3.6 Issues and AER considerations 14
3.7 AER conclusion 43

4 Cost of capital 46

4.1 Introduction 46
4.2 AER draft decision 46
4.3 Revised revenue proposal 47
4.4 Submissions 47
4.5 Issues and AER considerations 47
4.6 AER conclusion 64

5 Forecast operating expenditure 66

5.1 Introduction 66
5.2 AER draft decision 66
5.3 Revised revenue proposal 67
5.4 Submissions 67
5.5 Consultant review 68
5.6 Issues and AER considerations 68
5.7 AER conclusion 99

6 Efficiency benefit sharing ... 101

6.1 Introduction ... 101
6.2 AER draft decision ... 101
6.3 Revised revenue proposal ... 102
6.4 Issues and AER considerations ... 102
6.5 AER conclusion ... 105

7 Depreciation ... 107

7.1 Introduction ... 107
7.2 AER draft decision ... 107
7.3 Revised revenue proposal ... 107
7.4 Consultant review ... 108
7.5 Issues and AER considerations ... 109
7.6 AER conclusion ... 111

8 Service target performance incentives ... 112

8.1 Introduction ... 112
8.2 AER draft decision ... 112
8.3 Revised revenue proposal ... 114
8.4 Submissions ... 114
8.5 Issues and AER considerations ... 114
8.6 AER conclusion ... 116

9 Maximum allowed revenue ... 118

9.1 Introduction ... 118
9.2 AER draft decision ... 118
9.3 Revised revenue proposal ... 118
9.4 AER assessment of building blocks ... 120
9.5 AER determination—maximum allowed revenue ... 122
9.6 Average transmission charges ... 124

10 Negotiating framework for negotiated transmission services ... 126

10.1 Introduction ... 126
10.2 AER draft decision ... 126
10.3 Revised revenue proposal ... 126
10.4 AER determination ... 126

11 Negotiated transmission service criteria ... 127

11.1 Introduction ... 127
11.2 AER draft decision ... 127
11.3 Revised revenue proposal ... 127
11.4 AER determination ... 127

12 Pricing methodology ... 128

12.1 Introduction ... 128
12.2 AER draft decision ... 128
12.3 Revised proposed pricing methodology ... 128
12.4 Issues and AER considerations ... 129
12.5 AER determination ... 132

Glossary ... 133

Appendix A: Cost escalators 135
Appendix B: Contingent projects 155
Appendix C: Risk–free rate averaging period 162
Appendix D: Self insurance 174
Appendix E: Benchmark debt and equity raising costs 200
Appendix F: Definition of system minute 248
Appendix G: Performance incentive curves 249
Appendix H: New information and late submissions received by the AER 256

Shortened forms

ACCC	Australian Competition and Consumer Commission
ACCC 2005 revenue cap decision	ACCC, *NSW and ACT Transmission Network Revenue Cap TransGrid 2004–05 to 2008–09*, 27 April 2005
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CPI	consumer price index
current regulatory control period	1 July 20043 to 30 June 2009
draft decision	AER, *Draft decision, TransGrid transmission determination 2009–10 to 2010–14*, October 2008
final decision	AER, *Final decision, TransGrid transmission determination 2009–10 to 2010–14*, April 2009
MAR	maximum allowed revenue
NEL	National Electricity Law
NEM	national electricity market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
next regulatory control period	1 July 2009 to 30 June 2014
opex	operating and maintenance expenditure
PB	Parsons Brinckerhoff Australia Pty Ltd
revenue proposal	TransGrid, *Meeting customer needs for transmission services: TransGrid revenue proposal 1 July 2009 – 30 June 2014*, 31 May 2008
revised revenue proposal	TransGrid, *Meeting customer needs for transmission services: TransGrid revised revenue proposal 1 July 2009 – 30 June 2014*, January 2009
TNSP	transmission network service provider

Overview

Under the National Electricity Law (NEL) and the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission services provided by transmission network service providers in the national electricity market (NEM).

The AER has assessed TransGrid's 2009–2014 revenue proposal to determine if it is in accordance with the requirements of the NER. The AER released its draft decision on TransGrid's transmission determination in November 2008. The draft decision approved transmission charges increasing by 4.0 per cent per annum in real terms ($2008–09).

TransGrid submitted a revised revenue proposal in January 2009 indicating where it did not agree with the draft decision. Submissions on the draft decision and TransGrid's revised revenue proposal were received by the AER prior to making its final decision.

The AER engaged expert engineering consultants as well as financial and economic experts to assist it in making its assessment of the revised revenue proposal and stakeholder submissions. The AER's assessment was limited to those aspects of the draft decision which were not accepted in TransGrid's revised revenue proposal or related submissions. Where an aspect of the draft decision was not addressed in the revised revenue proposal or submissions, the determination made in the draft decision is confirmed in this final decision.

In the draft decision the AER, for the most part, accepted the need for the substantial capital works proposed by TransGrid over the next regulatory control period. Essentially, increased capital expenditure is needed in NSW to:

- augment the network to accommodate the growth in maximum demand for energy
- replace ageing assets
- improve network security and reliability.

After assessing TransGrid's revised revenue proposal against the requirements of the NER, the AER has determined that the capital expenditure proposed by TransGrid is greater than the amount required to meet the capital expenditure criteria. The AER has therefore determined that TransGrid's proposed capital expenditure of $2.5 billion ($2007–08) should be reduced to $2.4 billion which is an increase of over 72 per cent from the current level of $1.4 billion in the current regulatory control period in real terms ($2007–08). An indicative contingent projects allowance of $1.8 billion has also been approved by the AER. The draft decision approved a forecast capex allowance of $2.5 billion and a contingent projects allowance of $1.2 billion.

TransGrid considered the impact of slower economic growth since it submitted its June 2008 proposal but determined that its schedule of proposed capital expenditure would not be affected by revisions to maximum demand.

This final decision confirms the position taken in the draft decision that reductions to the forecast capital expenditure, although generally smaller, are required for the Dumaresq–Lismore line and the Cooma substation and Beaconsfield West replacement projects.

Similarly, smaller reductions are confirmed for the application of risk and scoping factors. This final decision also reinstates the instrument transformer program and accepts the Williamsdale stage 2 project into the ex ante capital expenditure allowance. Six new contingent projects, including the Sydney CBD and inner metropolitan area supply project, are also accepted in this final decision. These projects now have clearly specified triggers. Updated materials and labour input cost escalators, to reflect the latest available information, are also included in this final decision.

In the draft decision, the AER reduced TransGrid's forecast operating expenditure from $855 million ($2007–08) to $765 million. In response to matters raised in the draft decision, TransGrid revised its forecast opex proposal to $810 million. After assessing TransGrid's revised revenue proposal, the AER has determined that the operating expenditure allowance proposed is greater than that needed to meet the operating expenditure criteria of the NER.

For this final decision the AER has determined an operating expenditure allowance of $758 million ($2007–08) for TransGrid during the next regulatory control period. This amount represents a real increase of around 12.5 per cent in real terms ($2007–08), compared with TransGrid's level of operating expenditures in the current regulatory control period.

The reduction in the operating expenditure allowance from the draft decision is largely attributable to lower labour cost escalators.

During the current regulatory control period, TransGrid performed well against its service standard targets and, as a result, most service component parameter targets have been raised for the next regulatory control period. The market impact component of the service standards scheme will also apply to TransGrid in the next regulatory control period. This element supplements the service component by targeting outages that have an adverse impact on generator dispatch outcomes.

Outcome of regulatory process

As a result of the regulatory review process, over the course of the next regulatory control period, TransGrid will significantly increase investment in its transmission network. TransGrid has confirmed with the AER that it has access to sufficient finance to support its capital program.

Higher investment in the network will result in real increases in transmission charges and higher electricity prices for consumers. In the draft decision the AER estimated that the average transmission charge would increase in nominal terms by 6.6 per cent per year over the five years to 2013–14. In this final decision the AER has determined that the average transmission charge will increase by 4.8 per cent. The AER estimates that the increase in average transmission charges under this final decision will add approximately $2.80 to the average residential customer's annual bill of $983 (0.3 per cent). Transmission charges represent approximately 6 per cent on average of end user electricity charges in NSW.

This reduction in the growth rate of transmission charges reflects the impact of slower than expected growth in input costs, and lower yields on the 10–year Commonwealth Government bond rate compared with the rates and assumptions used in the draft decision. Under the NER the 10–year Commonwealth Government bond provides the basis for establishing TransGrid's cost of capital. The bond yield in the March 2009 reference period was 4.29 per cent compared with 5.46 per cent at the time of the draft decision.

Summary

Under chapter 6A of the NER the AER must make transmission determinations for TNSPs in respect of both prescribed and negotiated transmission services. This decision is the AER's final decision on the transmission determination that will apply to TransGrid for the regulatory control period 1 July 2009 to 30 June 2014.

This final decision on the transmission determination for TransGrid should be read in conjunction with the AER draft decision on the transmission determination for TransGrid, together with the consultants' reports. Except as specified in this final decision, the AER maintains its conclusions set out in the draft decision.

The key components of this final decision are:

- The AER's final revenue determination for TransGrid in respect of the provision of prescribed transmission services, including:
  - the opening RAB value for TransGrid
  - an assessment of the forecast capex allowance for TransGrid for the next regulatory control period
  - an estimate of the efficient benchmark weighted average cost of capital (WACC) for TransGrid
  - an assessment of the forecast opex allowance for TransGrid for the next regulatory control period
  - the AER's decision that the efficiency benefit sharing scheme is to apply to TransGrid for the next regulatory control period and an assessment of the total opex efficiency allowance under the efficiency carry forward mechanism accruing to TransGrid over the next regulatory control period
  - the AER's decision on TransGrid's regulatory depreciation allowance for the next regulatory control period
  - the AER's decision on the values to be attributed to the service target performance incentive scheme parameters that will apply to TransGrid for the next regulatory control period
  - the amount of the estimated total revenue cap for TransGrid for the provision of prescribed transmission services for the next regulatory control period.
- The AER's final determination on TransGrid's negotiating framework for negotiated transmission services.
- The AER's final determination on the negotiated transmission service criteria that will apply to TransGrid.
- The AER's final determination on TransGrid's proposed pricing methodology.

The AER's consideration of each of these components is summarised below. Further detail is provided in the relevant chapter and in the appendices attached to this final decision.

Opening asset base

AER draft decision

In the draft decision the AER determined that TransGrid's opening RAB should be $4234 million for the next regulatory control period (as at 1 July 2009).

TransGrid advised that during the current regulatory control period it has replaced a number of connection assets. Under clause 11.6.11 of the NER the AER assessed that these assets could not be considered to provide prescribed transmission services. Consequently, the AER removed the value of these replacement assets ($8.1 million) from the opening RAB.

Revised revenue proposal

TransGrid accepted the draft decision with the exception of the removal of $8.1 million of assets from TransGrid's opening RAB.

AER conclusion

Since the draft decision the roll forward of TransGrid's RAB has been updated to include the latest CPI data and the most recent forecast of capex for 2008–09 provided by TransGrid in its revised revenue proposal.

The AER maintains the position it took in the draft decision on TransGrid's connection assets. Under the NER, as it stood at the time TransGrid submitted its revenue proposal, the assets in question are properly characterised as providing negotiated transmission services and not prescribed transmission services. Therefore the assets in question cannot be included in TransGrid's opening RAB and have therefore been removed.

Using the updated data for net capex and CPI, the AER's application of the roll forward methodology has determined that TransGrid's opening RAB is $4218 million for the next regulatory control period (as at 1 July 2009). The AER's RAB roll forward calculations are set out in table 1.

Table 1: AER conclusion on TransGrid's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08	2008–09[a]
Opening RAB	3012.8	3103.9	3228.8	3397.9	3735.3
Actual net capex (adjusted for actual CPI and WACC)[b]	134.0	154.1	221.2	331.7	574.9
CPI adjustment on opening RAB	71.1	92.6	78.6	144.1	92.1
Straight-line depreciation (adjusted for actual CPI)	–113.9	–121.7	–130.8	–138.4	–155.3
Closing RAB	3103.9	3228.8	3397.9	3735.3	4247.0
Adjustment for difference between actual and forecast capex for 2003–04					–13.5
Adjustment for return on difference[c]					–7.8
Adjustment for connection assets providing negotiated transmission services					–8.1
Opening RAB at 1 July 2009					4217.5

(a) Updated with the actual CPI for 2008–09 (March to March). Based on updated net capex forecast.
(b) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.
(c) This relates to the difference between actual and forecast capex of $13.5 million for 1 July 2003 to 30 June 2004.

Forecast capital expenditure

AER draft decision

In the draft decision the AER did not accept TransGrid's proposed capex allowance of $2550 million ($2007–08) as it did not consider the proposed forecast capex reasonably reflected the capex criteria under clause 6A.6.7(c) of the NER.

On the basis of its analysis of TransGrid's proposed forecast capex, and the advice of Parsons Brinckerhoff Australia Pty Ltd (PB), the AER made several adjustments to TransGrid's proposal and considered that a forecast capex allowance of $2376 million ($2007–08) represented the total capex that a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives. In addition, the AER approved an indicative contingent projects allowance of $1.2 billion.

Revised revenue proposal

TransGrid's revised revenue proposal sought a capex allowance of $2516 million ($2007–08).

TransGrid implemented the draft decision in respect of forecast capex except in regard to:

- the Dumaresq−Lismore 330 kV line project

- the Cooma 132 kV substation replacement project
- the Beaconsfield West 132 kV gas insulated switchgear replacement project
- the instrument transformer replacement program
- the value and the application of project cost estimating factors
- the value of and the application of cost escalations
- cost estimation risk factors
- contingent projects.

TransGrid also proposed the inclusion of one additional project in its ex ante allowance—the Williamsdale stage 2 project—which was submitted as a contingent project in its revenue proposal.

TransGrid's revised revenue proposal included 15 contingent projects, with a total indicative cost of $1.9 billion.

AER conclusion

The AER is not satisfied that TransGrid's revised forecast capex proposal of $2516 million ($2007–08) reflects the capex criteria under clause 6A.6.7(c) of the NER. The AER is therefore required under clause 6A.14.1(2)(ii) to provide an estimate of the total capex that TransGrid will require over the next regulatory control period which the AER is satisfied reasonably reflects the capex criteria, taking into account the capex factors set out in clause 6A.6.7(e).

Based on its analysis and the advice of PB the AER has reduced TransGrid's revised capex proposal by $110 million. This represents a reduction of around 4.4 per cent of TransGrid's revised forecast capex proposal. The AER's amended capex allowance for the next regulatory control period is $2405 million and is set out in table 2 along with the adjustments made to TransGrid's revised capex proposal.

This amended allowance represents the AER's estimate of the total capex that a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives. The AER is satisfied that the amended ex ante capex allowance of $2405 million over the next regulatory control period, reasonably reflects the capex criteria, taking into account the capex factors.

The AER's conclusion on TransGrid's capex allowance is summarised in table 2.

The AER has approved an indicative contingent projects allowance of $1.8 billion. Six new contingent projects, including the Sydney CBD and inner metropolitan area supply project, and Queensland and Victorian interconnector development projects, have been accepted in this final decision. These projects now have clearly specified triggers.

Table 2: AER conclusion on TransGrid's forecast capex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Capex allowance (AER draft decision)	523.2	436.5	538.2	506.7	372.4	2376.5
TransGrid revised revenue proposal	530.2	460.1	585.3	536.0	403.9	2515.5
Adjustments resulting from detailed project review	–1.9	–6.3	–7.0	–8.0	–13.4	–36.6
Adjustment to cost accumulation process[a]	–2.7	–4.6	–25.6	–20.3	–9.7	–62.2
Adjustment to cost estimation risk factor	–1.3	–1.2	–1.7	–1.4	–1.1	–6.5
Cost estimating factors adjustment	–1.0	–0.9	–1.3	–1.0	–0.8	–5.1
Total adjustments	–6.9	–13.0	–35.6	–30.7	–24.2	–110.4
AER total capex allowance	523.3	447.1	549.7	505.2	379.7	2405.1

Note: Totals may not add up due to rounding.
(a) This includes adjustments to labour and materials cost escalators.

Cost of capital

AER draft decision

In the draft decision the AER determined a nominal vanilla WACC of 9.82 per cent for TransGrid. The WACC was greater than that proposed by TransGrid, as TransGrid proposed the use of the historical average of the cost of debt to calculate the WACC. The AER noted that it would update the WACC to reflect movements in the nominal risk–free rate and debt risk premium, based on the agreed averaging period, and the expected inflation rate at a time closer to its final decision.

Revised revenue proposal

TransGrid did not agree with the AER's decision on the averaging period for the risk–free rate and the debt risk premium. TransGrid proposed that the averaging period be revised to exclude the impacts of the global financial crisis. Based on the revised averaging period, TransGrid proposed a nominal risk–free rate of 5.86 per cent.

TransGrid did not agree with the AER's method for setting the debt risk premium based on Bloomberg fair yield estimates of corporate bonds. TransGrid proposed that a simple average of fair yield estimates from Bloomberg and CBASpectrum be adopted for a more reliable estimate of the debt risk premium. Based on this approach, TransGrid proposed a debt risk premium of 3.21 per cent.

TransGrid accepted the AER's proposed inflation forecast, based on the Reserve Bank of Australia forecasts, but only if the AER adopted TransGrid's revised revenue proposal averaging period for the risk–free rate.

AER conclusion

The AER has determined a nominal vanilla WACC of 8.79 per cent for TransGrid, using an updated risk–free rate and debt risk premium, and other parameters prescribed under chapter 6A of the NER. Table 3 sets out the WACC parameter values used in this final decision. The AER's WACC is lower than TransGrid's revised revenue proposal WACC because of a lower nominal risk–free rate—commensurate with monetary policy and softening in economic growth—adopted for this final decision.

Table 3: AER conclusion on TransGrid's WACC parameters

Parameter	AER conclusion
Risk–free rate (nominal)	4.29%
Risk–free rate (real)[a]	1.77%
Expected inflation rate	2.47%
Debt risk premium	3.49%
Market risk premium	6.00%
Gearing	60%
Equity beta	1.00
Nominal pre–tax return on debt	7.78%
Nominal post–tax return on equity	10.29%
Nominal vanilla WACC	8.79%

(a) The real risk–free rate was calculated using the Fisher equation.

The AER considers that its decision to withhold agreement to the averaging period in TransGrid's revenue proposal is reasonable and that the agreed averaging period is consistent with finance theory, regulatory practice, the NER and NEL. The AER considers that the material provided by TransGrid in support of its revised revenue proposal does not justify that an averaging period prior to September 2008 is better than a period that is as close as practically possible to the start of the next regulatory control period.

The AER considers that only Bloomberg data should be used to estimate the debt risk premium based on its analysis of the fair yields reported by Bloomberg and CBASpectrum, observed yields of BBB+ corporate bonds and the methodologies adopted by these two data providers.

The AER maintains its draft decision to apply a methodology to determine a forecast inflation rate over a 10–year period using the RBA's inflation forecasts for the first two years and the mid–point of the RBA's target inflation range for the remaining eight years.

The AER considers that, consistent with the draft decision, this methodology provides the best estimate of a 10–year inflation forecast to be applied in the post–tax revenue model for this final decision.

Forecast operating expenditure

AER draft decision

In the draft decision the AER did not accept TransGrid's forecast opex requirement of $855 million ($2007–08) as it did not consider the proposed opex forecast reasonably reflected the opex criteria under clause 6A.6.6(c) of the NER.

On the basis of its analysis of TransGrid's proposed opex forecast and the advice of PB, the AER applied a reduction of $90 million to TransGrid's proposed opex allowance. This represented a reduction of around 11 per cent and resulted in an amended forecast opex allowance of $765 million which the AER considered represents the total opex costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives in clause 6A.6.6.

Revised revenue proposal

TransGrid implemented the draft decision in respect of forecast opex except in relation to:

- labour cost escalators
- defect maintenance expenditures for new growth assets
- self insurance costs
- debt raising costs
- equity raising costs.

AER conclusion

The AER is not satisfied that TransGrid's revised forecast total opex proposal of $810 million ($2007–08) reasonably reflects the opex criteria under clause 6A.6.6(c) of the NER. The AER is therefore required under clause 6A.14.1(3)(ii) to provide an estimate of the total opex that TransGrid will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors set out in clause 6A.6.6(e).

On the basis of its analysis of TransGrid's proposed opex forecast and the advice of PB, the AER has applied a reduction of $52 million to TransGrid's revised opex proposal. This represents a reduction of around 6.4 per cent of TransGrid's revised forecast opex proposal. The AER's amended forecast opex allowance for the next regulatory control period is $758 million and is set out in table 4.

This amended allowance represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives. The AER is satisfied that the amended total forecast opex allowance of $758 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors.

Table 4: AER conclusion on TransGrid's forecast opex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's revised proposed controllable opex	128.5	138.4	142.7	152.5	155.7	717.8
Debt raising costs	3.7	4.0	4.3	4.7	5.0	21.7
Equity raising costs[a]	1.1	1.9	3.0	3.8	3.8	13.6
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance	2.2	2.2	2.2	2.2	2.2	11.0
TransGrid's total opex	157.1	152.5	158.2	169.1	172.7	809.6
AER controllable opex	127.6	135.0	138.1	145.4	145.7	691.7
Debt raising costs	1.9	2.1	2.2	2.4	2.6	11.2
Equity raising costs[b]	–	–	–	–	–	–
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance	1.8	1.8	1.8	1.8	1.8	9.2
AER total opex allowance	152.9	144.9	148.2	155.6	156.1	757.6

Note: Totals may not add up due to rounding.
(a) The proposed equity raising cost allowance does not include an estimate for retained earnings. TransGrid's cash flow modelling provided with its revised revenue proposal PTRM calculated total equity raising costs of $38 million ($2007–08).
(b) The AER will allow TransGrid to amortise a total of $3.1 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.

Efficiency benefit sharing

AER draft decision

In the draft decision the AER determined a total opex efficiency allowance under the efficiency carry forward mechanism (ECFM) of $8.9 million ($2008–09) for TransGrid over the next regulatory control period and decided it would apply the efficiency benefit sharing scheme (EBSS) to TransGrid for the next regulatory control period. The AER decided to exclude five opex cost categories from the operation of the EBSS for the next regulatory control period.

Revised revenue proposal

TransGrid has implemented all aspects of the draft decision with the exception of the ex post demand growth adjustment method.

TransGrid stated that the high and low growth scenarios cited by the AER in the draft decision were not those used by TransGrid in forecasting its capex program.

AER conclusion

The AER has updated the efficiency gains/losses for TransGrid under the ECFM using actual inflation for 2008–09 (March to March) and TransGrid's updated forecast of opex for 2008–09 to determine a total opex efficiency allowance of $15.1 million ($2008–09) for TransGrid over the next regulatory control period, as shown in table 5.

Table 5: AER conclusion on TransGrid's opex efficiency allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012-13	2013–14	Total
Opex efficiency allowance	5.7	4.5	5.4	2.2	–2.7	15.1

The AER will apply the EBSS to TransGrid for the next regulatory control period. It has corrected the reference to the range of growth scenarios used by TransGrid for the purposes of an ex post demand growth adjustment for the EBSS. The AER also maintains its draft decision to exclude the opex cost categories of debt raising costs, self insurance costs, insurance costs, superannuation costs relating to defined benefit and retirement schemes, and non–network alternatives from the operation of the EBSS for the next regulatory control period.

Depreciation

AER draft decision

The AER considered that TransGrid's proposed depreciation schedule did not comply with the NER requirements and therefore recalculated the depreciation allowance. Specifically, the AER revised TransGrid's proposed asset lives to align the treatment of standard lives for replacement asset classes with augmentation asset classes. The AER also reviewed TransGrid's proposed method for transitioning to recognise its capex on a partially as–incurred approach and considered that it had been implemented appropriately in the post–tax revenue model.

On the basis of the approved asset lives, opening RAB, forecast capex allowance and the transitional arrangement to recognise capex on a partially as–incurred approach, the AER determined TransGrid's depreciation schedule and regulatory depreciation allowance for for the next regulatory control period.

Revised revenue proposal

TransGrid accepted all elements of the draft decision on depreciation except for the change to the standard asset lives for the replacement asset category of asset classes. In TransGrid's opinion, and based on advice from NERA Economic Consulting:

- the AER had not expressed why it rejected TransGrid's use of a replacement asset category of asset classes and corresponding standard asset lives
- there is no NER requirement that the regulatory life should reflect the technical life of an asset
- the AER is correct in assuming that large replacements assets such as transformers and reactors would be stored, refurbished and re–used

- the AER is incorrect in assuming that other assets such as switch gear would be reused.

AER conclusion

The AER maintains its draft decision and does not consider that TransGrid's proposal to allocate the majority of new replacement capex into the replacement category of asset classes, with reduced standard asset lives, for regulatory depreciation purposes to be reasonable. The AER is not satisfied that these new replacement assets would not achieve the economic lives that would be consistent with the technical lives for new augmentation assets.

Accordingly, the AER does not accept the standard asset lives proposed for the replacement asset category of asset classes. The AER considers that TransGrid's proposed depreciation schedule does not conform with the NER requirements and therefore has recalculated the depreciation allowance for this final decision.

On the basis of the approved asset lives, opening RAB, forecast capex allowance and the transitional arrangements to recognise capex on a partially as–incurred approach, the AER has determined TransGrid's depreciation schedule. The depreciation schedule is used to calculate the regulatory depreciation allowance for the next regulatory control period in accordance with clause 6A.6.3(a)(2)(ii), as set out in table 6.

Table 6: AER conclusion on TransGrid's regulatory depreciation allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Straight-line depreciation	179.0	191.6	193.5	215.6	238.2	1018.0
Less: inflation adjustment on RAB	104.4	116.5	126.7	140.3	152.8	640.7
Regulatory depreciation	74.6	75.2	66.8	75.3	85.4	377.3

Service target performance incentive

AER draft decision

In the draft decision the AER largely accepted TransGrid's service target performance incentive proposal, but also made a number of adjustments. The draft decision on TransGrid's performance targets, caps, collars and weightings for the service component of the scheme are set out in table 7.

Table 7: AER draft decision on TransGrid's service component performance targets, caps, collars, and weightings

Parameter	Collar	Target	Cap	Weighting
Transmission circuit availability (%)				*MAR (%)*
Transmission line availability	99.05	99.26	99.36	0.20
Transformer availability	97.26	98.55	98.84	0.15
Reactive plant availability	98.65	99.12	99.33	0.10
Loss of supply event frequency (no.)				*MAR (%)*
> 0.05 (x) system minutes	7	4	2	0.25
> 0.25 (y) system minutes	2	1	0	0.10
Average outage duration (minutes)				*MAR (%)*
Total	999	824	649	0.20

The draft decision on TransGrid's performance target, cap and weighting for the market impact component of the scheme are set out table 8.

Table 8: AER draft decision on TransGrid's market impact component performance target, cap and weighting

Parameter	Values		
Market impact	**Target**	**Cap**	**Weighting**
	Number of dispatch intervals with a marginal value greater than $10/MWh		*MAR (%)*
	2857	0	2.0

Revised revenue proposal

TransGrid implemented the draft decision in respect of the service component and the market impact component of the scheme. Subsequent to submitting its revised revenue proposal, TransGrid advised the AER that due to changes in capex modelling for its revised revenue proposal, the transformer availability parameter performance target, cap and collar have increased.

AER conclusion

The AER accepts the updated transformer availability parameter performance target, cap and collar provided by TransGrid.

The service component performance targets, caps, collars and weighting to apply to TransGrid during the next regulatory control period are set out in table 9.

Table 9: AER conclusion on TransGrid's service component performance targets, caps, collars and weightings

Parameter	Collar	Target	Cap	Weightings
Transmission circuit availability (%)				*MAR (%)*
Transmission line availability	99.05	99.26	99.36	0.20
Transformer availability	97.33	98.61	98.89	0.15
Reactive plant availability	98.65	99.12	99.33	0.10
Loss of supply event frequency (No.)				*MAR (%)*
>0.05 (x) system minutes	7	4	2	0.25
>0.25 (y) system minutes	2	1	0	0.10
Average outage duration (minutes)				*MAR (%)*
Total	999	824	649	0.20

The market impact component target, cap and weighting to apply to TransGrid during the next regulatory control period are set out in table 10.

Table 10: AER conclusion on TransGrid's market impact component performance target, cap and weighting

Parameter	Values		
Market impact	**Target**	**Cap**	**Weighting**
	Number of dispatch intervals with a marginal value greater than $10/MWh		*MAR (%)*
	2857	0	2.0

Maximum allowed revenue

AER draft decision

In the draft decision the AER determined an annual building block revenue requirement for TransGrid that increased from $678 million in 2009–10 to $891 million in 2013–14 ($nominal). The AER determined a nominal expected MAR (smoothed) for TransGrid that increases from $678 million in 2009–10 to $891 million in 2013–14. The total revenue cap for TransGrid over the next regulatory control period was calculated to be $3906 million.

Revised revenue proposal

TransGrid proposed nominal unsmoothed revenues of $707 million in 2009–10, increasing to $973 million in 2013–14. The proposed nominal expected MAR (smoothed) increases from $707 million in 2009–10 to $960 million in 2013–14. TransGrid's MAR for the final year of its current regulatory control period (2008–09) is $622 million.

TransGrid stated that its revised revenue proposal would result in an average annual increase in transmission charges of 4.4 per cent (real). As TransGrid's costs represent about 6 per cent of the total delivered price for the average energy user, the impact on the price to consumers is estimated to be about $4.90 a year for the typical household in NSW.

AER conclusion

The AER determines an annual building block revenue requirement for TransGrid that increases from $633 million in 2009–10 to $832 million in 2013–14 ($nominal). The NPV of the annual building block revenue requirement for the next regulatory control period has been calculated to be $2798 million. Based on this NPV amount, the AER determines a nominal expected MAR (smoothed) for TransGrid that increases from $633 million in 2009–10 to $820 million in 2013–14, as shown in table 11. The total revenue cap for TransGrid over the next regulatory control period is $3616 million.

Table 11: AER final decision on the maximum allowed revenue ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Return on capital	370.6	413.4	449.8	498.1	542.6	2274.4
Regulatory depreciation	74.6	75.2	66.8	75.3	85.4	377.3
Opex allowance	162.5	157.8	165.4	178.0	182.9	846.5
Opex efficiency allowance[a]	5.8	4.7	5.8	2.5	–3.0	15.7
Net tax allowance	19.4	20.1	19.2	21.8	24.4	104.9
Annual building block revenue requirement (unsmoothed)	632.8	671.3	706.9	775.7	832.2	3618.9
MAR (smoothed)	632.8	675.1	720.2	768.3	819.6	3616.0
X factor (%)	n/a[b]	–4.10	–4.10	–4.10	–4.10	n/a

(a) An allowance for opex efficiency resulting from the carry forward mechanism applied in the current regulatory control period.

(b) The MAR for 2009–10 is set at $632.8 million and TransGrid is not required to apply an X factor. The MAR in the first year of the next regulatory control period (2009–10) is around 1.8 per cent higher than the MAR in the final year of the current regulatory control period (2008–09).

To determine the expected MAR (smoothed) over the next regulatory control period the AER has set the first year MAR equal to the annual building block revenue requirement for that year and applied an X factor of –4.10 per cent in subsequent years. The AER's revenue determination for TransGrid is set out in part 1 of the transmission determination.

TransGrid's MAR for the next regulatory control period is established through a building block approach. While the AER assesses TransGrid's proposed pricing methodology, actual transmission charges established at particular connection points are not approved by the AER. TransGrid establishes its transmission charges in accordance with its approved pricing methodology and the NER.

The effect of the AER's final decision on average transmission charges can be estimated by taking the annual MAR and dividing it by forecast annual energy delivered in NSW. Based on this approach, the AER estimates that this final decision will result in a 4.8 per cent per annum (nominal) increase in average transmission charges in the next regulatory control period or an increase of 2.3 per cent per annum in real terms ($2008–09).

Negotiating framework

AER draft decision

The AER determined that TransGrid's negotiating framework complied with clause 6A.9.5(c) of the NER.

Revised revenue proposal

TransGrid did not amend its negotiating framework in its response to the draft decision.

AER conclusion

The AER has affirmed its draft decision and therefore the negotiating framework set out in part 2 of the transmission determination will apply to TransGrid for the next regulatory control period.

Negotiated transmission service criteria

AER draft decision

As required by the NER, the AER determined the negotiated transmission service criteria that gave effect to, and were consistent with, the negotiated transmission service principles set out in clause 6A.9.1.

Revised revenue proposal

TransGrid did not address the negotiated transmission service criteria in its response to the draft decision.

AER conclusion

The AER has affirmed its draft decision and therefore the negotiated transmission service criteria set out in part 3 of the transmission determination will apply to TransGrid for the next regulatory control period.

Pricing methodology

AER draft decision

In the draft decision the AER assessed TransGrid's proposed pricing methodology against part J of the NER and the pricing methodology guidelines. Based on its assessment, the AER decided not to approve TransGrid's proposed pricing methodology. The NER requires that if the AER refuses to approve any aspect of a proposed pricing methodology, the draft decision must include details of the changes required or the matters to be addressed before the AER will approve the proposed pricing methodology. The AER stated that the matters that TransGrid must address in its revised proposed pricing methodology were:

- to propose an alternative locational pricing structure which is consistent with clause 6A.23.4(e) of the NER and does not include a measure of energy
- to include additional details on its approach to allocating costs to assets that provide both prescribed entry and prescribed exit services.

The AER also stated that it would be beneficial for TransGrid to specify the points in the transmission network where costs will be allocated and prices determined.

Revised revenue proposal

TransGrid has implemented the draft decision with the exception of specifying the points in the transmission network where costs will be allocated and prices determined.

TransGrid submitted a revised proposed pricing methodology which included a demand based locational pricing structure which it considered complied with the guidelines.

AER conclusion

The AER has assessed TransGrid's amended revised proposed pricing methodology, as submitted on 2 February 2009, against part J of the NER and the pricing methodology guidelines. The AER has determined that TransGrid's amended revised proposed pricing methodology set out in part 4 of the transmission determination complies with the NER and the pricing methodology guidelines.

1 Introduction

1.1 Background

Under the National Electricity Law (NEL) and the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission services provided by transmission network service providers (TNSPs) in the National Electricity Market (NEM).

The AER makes transmission determinations in accordance with chapter 6A of the NER in respect of certain services provided by transmission businesses. In performing these obligations, the AER is responsible for regulating:

- the revenues that TNSPs may earn from providing prescribed transmission services
- the terms and conditions of access and the access charges to be applied by TNSPs for providing negotiated transmission services.

The AER is required to provide TransGrid an opportunity to recover sufficient revenues to meet the efficient costs of maintaining its network.

The Australian Competition and Consumer Commission (ACCC) determined TransGrid's current revenue cap for a five–year period from 1 July 2004 to 30 June 2009 (the current regulatory control period)[1] under the National Electricity Code, which has been superseded by the NER.

On 31 May 2008 TransGrid submitted to the AER its revenue proposal[2], proposed negotiating framework[3] and proposed pricing methodology[4] for 1 July 2009 to 30 June 2014 (the next regulatory control period). The draft decision on these matters was published on 28 November 2008.[5] TransGrid submitted a revised revenue proposal[6] and pricing methodology[7] on 14 January 2009. The AER published these documents on its website on 19 January 2009.

This final decision should be read in conjunction with the draft decision for TransGrid published by the AER on 28 November 2008.

1.2 AER draft decision

Based on its assessment of the building block components and using the post tax revenue model, the AER determined a maximum allowed revenue (MAR) for TransGrid that

---

1 ACCC, *NSW and ACT transmission network revenue cap TransGrid 2004–05 to 2008–09, final decision*, 27 April 2005. This revenue cap was revoked and substituted by the AER in February 2007.

2 TransGrid, *Meeting customer needs for transmission services, TransGrid revenue proposal, 1 July 2009 – 30 June 2014*, May 2008.

3 TransGrid, *Proposed negotiating framework for provision of a negotiated transmission service, 1 July 2009 to 30 June 2014*, 30 May 2008.

4 TransGrid, *Proposed pricing methodology, 1 July 2009 to 30 July 2014*, May 2008.

5 AER, *Draft decision, TransGrid transmission determination 2009–10 to 2013–14*, 31 October 2008.

6 TransGrid, *Meeting customer needs for transmission services, TransGrid revised revenue proposal, 1 July 2009 – 30 June 2014*, January 2009.

7 TransGrid, *Proposed pricing methodology, 1 July 2009 to 30 July 2014*, January 2009.

increases from $678 million in 2009–10 to $891 million in 2013–14 (nominal). TransGrid's total MAR for the next regulatory control period was determined to be $3906 million (nominal). Table 1.1 sets out the annual building block calculations.

Table 1.1: AER draft decision on annual building block revenue requirement ($m, nominal)

	2009–10	20010–11	2011–12	2012–13	2013–14	Total
Return on capital	415.9	464.2	504.3	557.9	608.5	2550.8
Regulatory depreciation	71.9	72.6	64.6	73.5	82.7	365.3
Opex allowance	168.1	162.2	171.7	182.5	184.1	868.5
Opex efficiency allowance[a]	4.5	3.2	4.1	1.0	–3.9	8.9
Net tax allowance	22.5	23.7	23.0	26.0	29.0	124.4
Annual building block revenue requirement (unsmoothed)	678.4	722.7	763.6	840.0	904.3	3909.0
Maximum allowed revenue (smoothed)	678.4	726.3	777.5	832.4	891.1	3905.7
X factor (%)	n/a	–4.39	–4.39	–4.39	–4.39	n/a

(a) An allowance for opex efficiency resulting from the carry forward mechanism applied in the current regulatory control period.

The AER estimated that the increase in average transmission charges under the draft decision would add approximately $4.00 to the average residential customer's annual bill of $983 (0.4 per cent).

The AER assessed TransGrid's negotiating framework and considered the negotiating framework to be compliant with clause 6A.9.5(c) of the NER. The AER approved TransGrid's proposed negotiating framework for the next regulatory control period and also specified the negotiated transmission service criteria for TransGrid for the next regulatory control period.

1.3 Revised revenue proposal

TransGrid submitted its revised revenue proposal to the AER on 14 January 2009. The revised revenue proposal indicated where TransGrid has implemented changes required by the draft decision. Where TransGrid has not fully accepted the requirements of the draft decision its revised revenue proposal provided additional information to address the matters raised by the AER. TransGrid also sought to demonstrate that the revised revenue proposal satisfies the requirements of the NER.

TransGrid's revised revenue proposal sets out a MAR requirement that increases from $707 million in 2009–10 to $973 million in 2013–14 ($nominal), with a total MAR of $4147 million for the next regulatory control period.

TransGrid's revised opening regulatory asset base (RAB) is $4276 million (as at 1 July 2009). TransGrid accepted all aspects of the draft decision on the opening RAB except the exclusion of $8.1 million of connection assets which the AER considered provided negotiated transmission services.

TransGrid's revised capex forecast for the next regulatory control period is $2516 million ($2007–08). It implemented most aspects of the draft decision relating to forecast capex, except those related to:

- the Dumaresq−Lismore 330 kV line project costs
- the Cooma 132 kV substation replacement project costs
- the Beaconsfield West 132 kV gas insulated switchgear replacement project costs
- the instrument transformer replacement program costs
- the value and the application of project cost factors
- the value and the application of cost escalations
- cost estimation risk factors
- contingent projects.

TransGrid's revised forecast opex for the next regulatory control period is $810 million ($2007–08). It implemented all aspects of the draft decision relating to opex, except those related to:

- labour cost escalation
- defect maintenance costs for new assets
- self insurance costs
- debt raising costs
- equity raising costs.

TransGrid accepted most other elements of the draft decision relating to the efficiency benefit sharing scheme (EBSS), depreciation, service target performance incentive scheme, arrangements for negotiation and the pricing methodology, with the following exceptions:

- the demand growth adjustment for the EBSS should be based on NSW summer 10 per cent probability of exceedence (POE) and winter 90 per cent POE
- replacement new assets (except for transformers and reactors) should have different standard lives than augmentation assets
- the locations where transmission prices are determined do not need to be included in the pricing methodology as they are published annually.

1.4 Review process

The AER assessed TransGrid's revenue proposal, proposed negotiating framework and proposed pricing methodology in accordance with the review process outlined in part E of chapter 6A of the NER. To date, this process has involved:

- Pre–consultation—TransGrid and the AER agreed on the provision of supporting information and documents by TransGrid as part of the review process.
- Proposal—TransGrid submitted its revenue proposal, proposed negotiating framework and proposed pricing methodology to the AER on 31 May 2008, 13 months prior to the end of its current regulatory control period. The AER assessed TransGrid's proposal against chapter 6A of the NER and the AER transmission guidelines.
- Public consultation—the AER published TransGrid's revenue proposal and the AER's proposed negotiated transmission service criteria for TransGrid on 26 June 2008 and called for interested parties to make submissions. The AER held a public forum on TransGrid's revenue proposal on 30 July 2008, where TransGrid made a presentation and interested parties asked questions of TransGrid.
- Submissions—the AER received four submissions on TransGrid's revenue proposal. These were from the Energy Market Reform Forum, the Energy Users Association of Australia, Norske Skog and Snowy Hydro Limited.
- Assessment by a technical expert—The AER engaged Parsons Brinckerhoff Australia Pty Ltd (PB) as a technical expert to advise it on a number of key aspects of TransGrid's revenue proposal.
- Additional technical/specialist advice—The AER engaged Nuttall Consulting to provide it with technical and engineering advice throughout the review process. The AER engaged McLennan Magasanik Associates (MMA) to undertake a desk top review of the methods and processes used by TransGrid to develop its demand forecasts. The AER also engaged Econtech to provide a forecast of NSW labour cost growth.
- Draft decision—The AER made its draft decision on TransGrid's transmission determination on 31 October 2008. The draft decision was published on 28 November 2008 and the AER requested submissions from interested parties.
- Public consultation—The AER held a pre–determination conference on its draft decision on 9 December 2008 to explain its draft decision and receive oral submissions from interested parties.
- Revised revenue proposal—TransGrid submitted its revised revenue proposal on 14 January 2009. The AER has assessed TransGrid's revised revenue proposal against chapter 6A of the NER.
- Revised proposed pricing methodology—TransGrid submitted its revised proposed pricing methodology to the AER on 14 January 2009. The AER has assessed TransGrid's revised proposed pricing methodology against the NER and the AER's pricing methodology guidelines released on 29 October 2007.
- Submissions—The AER received a total of 13 submissions from five interested parties (TransGrid, Newcrest, the Energy Users Association of Australia, EnergyAustralia and Powerlink) in response to the draft decision and TransGrid's

revised revenue proposal. Six submissions were provided after the closing date for submissions on 16 February 2009. The late submissions are listed in appendix H.

- Assessment by a technical expert—The AER retained PB to advise the AER in relation to a number of aspects of TransGrid's revised revenue proposal. Specifically, the AER asked PB to provide its opinion on:

  - capex issues—specific projects' scope and costs, project cost factors, application of escalators, cost estimation risk factors, revised scope and triggers for contingent projects

  - opex issues—defect maintenance costs for new assets

  - standard asset lives for the replacement category of asset classes.

  PB provided its opinion to the AER on these issues and also responded to comments raised in submissions. PB's advice represents its independent views based on its review. The AER has considered this advice in making its final decision. The terms of reference guiding PB's review are set out in chapter 1 of its report. The AER also engaged Associate Professor John Handley from the University of Melbourne to advise on issues relating to the cost of capital, and benchmark debt and equity raising transaction costs.

- Final decision—The AER made its final decision on TransGrid's transmission determination on 28 April 2009.

1.5 Structure of final decision

This final decision sets out the AER's consideration of TransGrid's revised revenue proposal, including substantive issues raised in submissions. Except as specified in this final decision, the AER maintains its conclusions set out in the draft decision. Therefore, this final decision should be read in conjunction with the draft decision.

The AER's consideration of TransGrid's revenue proposal, proposed negotiating framework and proposed pricing methodology, together with the negotiated transmission service criteria to apply to TransGrid, are set out as follows:

- chapters 2 to 7 set out the AER's analysis and conclusions regarding the revised building block components

- chapter 8 specifies the performance values for each of the parameters applying under the service target performance incentive scheme

- chapter 9 sets out the maximum allowed revenue for the next regulatory control period

- chapter 10 and 11 deal with the arrangements for negotiated transmission services

- chapter 12 assesses TransGrid's revised pricing methodology.

2 Opening regulatory asset base

2.1 Introduction

This chapter sets out the method used by the AER to determine TransGrid's closing regulatory asset base (RAB) for the current regulatory control period. The closing RAB becomes the opening RAB for the next regulatory control period and is used to calculate TransGrid's maximum allowed revenue (MAR). This chapter also sets out the AER's consideration of issues raised in response to the draft decision on the opening asset base for TransGrid. No submissions were received on this issue.

2.2 AER draft decision

In the draft decision, the AER reviewed inputs to the roll forward model (RFM) for the previous regulatory control period—1 July 2003 to 30 June 2004—and was satisfied with TransGrid's proposed adjustments to the opening RAB for the current regulatory control period.[8] The AER accepted the adjustments to TransGrid's RAB of $14 million for the difference between actual and forecast capex, and $7.9 million associated with the excess return on that difference.[9] The AER also reviewed the inputs to the RFM for the current regulatory control period and made the following adjustments.

TransGrid advised that during the current regulatory control period it has replaced a number of connection assets. These assets were committed to be constructed after 9 February 2006.[10] In accordance with clause 11.6.11 of the NER these assets could not be considered to provide prescribed transmission services. Consequently, in accordance with clause 6A.6.1 of the NER the AER removed the value of these replacement assets ($8.1 million) from the opening RAB.[11]

TransGrid provided its actual capex for 2007–08, which was made available subsequent to lodgement of its revenue proposal, and an update of the expected capex for 2008–09. Some errors were also identified during the review process and these were corrected by TransGrid. The AER reviewed the updated inputs and accepted that they were appropriate for the purposes of the RFM. The net impact of these adjustments was a decrease of $3 million to TransGrid's proposed opening RAB.[12]

The AER determined that TransGrid's opening RAB should be $4234 million for the next regulatory control period (as at 1 July 2009). The AER's RAB roll forward calculations are set out in table 2.1.

8 AER, *Draft decision*, p. 12.
9 AER, *Draft decision*, p. 12.
10 TransGrid, *Meeting customer needs for transmission services TransGrid revised revenue proposal, 1 July 2009 – 30 June 2014*, January 2009, pp. 9–11.
11 AER, *Draft decision*, p. 12.
12 AER, *Draft decision*, pp. 9–11.

Table 2.1: AER draft decision on TransGrid's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08	2008–09
Opening RAB	3012.8	3103.9	3228.8	3397.9	3737.0
Actual net capex (adjusted for actual CPI and WACC)	134.0	154.1	221.2	333.4	577.3
CPI adjustment on opening RAB	71.1	92.6	78.6	144.1	104.6
Adjustment for straight–line depreciation (adjusted for actual CPI)	–113.9	–121.7	–130.8	–138.4	–155.5
Closing RAB	3103.9	3228.8	3397.9	3737.0	4263.5
Adjustment for difference between actual and forecast capex for 2003–04					–13.6
Adjustment for return on difference					–7.9
Adjustment for connection assets providing negotiated transmission services					–8.1
Opening RAB at 1 July 2009					4234.0

Source: AER, *Draft decision*, p. 12.

2.3 Revised revenue proposal

TransGrid accepted the draft decision with the exception of the removal of $8.1 million of assets from TransGrid's opening RAB.[13]

2.4 Issues and AER considerations

2.4.1 Adjustment for connection assets

In its revised revenue proposal TransGrid advised the AER that during the current regulatory control period it replaced a number of connection assets.[14] These connection assets were committed to be constructed after 9 February 2006 and under clause 11.6.11 of the NER they would not be considered to provide prescribed transmission services. Clause 6A.6.1 of the NER provides that the opening RAB is to only incorporate assets that provide prescribed transmission services. For this reason the AER removed $8.1 million from TransGrid's opening RAB in the draft decision.[15]

Subsequent to the draft decision, clause 11.6.11 of the NER was amended by the Australian Energy Market Commission (AEMC). The amendment took effect on 13 February 2009. TransGrid foreshadowed this amendment in its revised revenue proposal and stated that, under the amended clause, the assets in question are replacement assets and would now qualify as providing prescribed transmission services.[16] It

[13] TransGrid, *Revised revenue proposal*, pp. 9–10.
[14] TransGrid, *Revised revenue proposal*, pp. 10–11.
[15] AER, *Draft decision*, p. 11.
[16] TransGrid, *Response to issue 304*, 11 February 2009, p. 3.

considered that the AER is now required to adopt this classification in making its final decision. Furthermore TransGrid considered that chapter 6A of the NER does not prevent the AER from amending its draft decision to reflect a change in the NER which will commence before it issues its final decision.[17]

Subsequent to submission of the revised revenue proposal, the AER advised TransGrid that it was considering the application of section 33(1)(b) of schedule 2 of the NEL to the rule change. TransGrid provided further information on its interpretation of section 33(1)(b) of schedule 2 of the NEL, and the effect on TransGrid's revenue determination process.[18]

Section 33(1)(b) of schedule 2 of the NEL provides that:

> (1) The repeal, amendment or expiry of a provision of this Law, the Regulations or the Rules does not:
>
> (b) affect the previous operation of the provision or anything suffered, done or begun under the provision.

The AER considers that the meaning of this provision is that a rule change cannot affect anything 'suffered, done or begun' under the rule before the rule change took effect. This means that anything done or suffered under clause 11.6.11 is not affected by the amendment, and anything begun while the old clause 11.6.11 was in force is not affected by the rule change. The submission of TransGrid's revenue proposal, the making of submissions by stakeholders, and the release of the draft decision, are all things 'suffered, done or begun' under the previous clause 11.6.11. The AER considers that a revenue determination process as a whole begins when the TNSP submits its revenue proposal and ends when the AER makes its final decision, and notes that neither the AER nor the TNSP has complete freedom to depart from what is in that revenue proposal. TransGrid submitted its revenue proposal prior to the new rule taking effect and therefore the previous clause 11.6.11 should apply.

During the rule change process, the AEMC considered the issue of allowing a reopening of a revenue determination in respect of current processes underway to incorporate relevant assets for determinations made before the new clause 11.6.11 took effect. The AEMC decided against allowing a reopening, noting:[19]

> On one interpretation of the NEL, a Rule change may not apply to existing processes. The proposed reopening of processes already underway may not be within the Rule making powers of the Commission.

The AEMC cited section 33(1) of schedule 2 of the NEL to support this interpretation. It appears that the AEMC had reservations about applying the rule change to existing processes.

The AER considers that the application of section 33(1)(b) of schedule 2 of the NEL means that the amendment of clause 11.6.11 of the NER will have no effect on TransGrid's current revenue determination process because the process began when the

[17] TransGrid, *Response to issue 304*, 11 February 2009, p. 5.

[18] TransGrid, *Response to issue 304*, 27 February 2009.

[19] AEMC, *Rule Determination National Electricity Amendment (Cost allocation arrangements for transmission services) Rule 2009 No. 3*, 29 January 2009, p. 54.

unamended clause was in place and both TransGrid and the AER have 'done' certain things under the unamended clause.

For the reasons given in the draft decision, under clause 11.6.11 of the NER as it stood at the time TransGrid submitted its revenue proposal, the assets in question are properly characterised as providing negotiated transmission services and not prescribed transmission services. Therefore under clause 6A.6.1 of the NER the assets in question cannot be included in TransGrid's opening RAB and have been removed.

2.4.2 Updated data

Since the draft decision the roll forward of TransGrid's RAB has been updated to include the latest consumer price index (CPI) data which was published by the Australian Bureau of Statistics in April 2009. TransGrid noted in its revised revenue proposal that the AER would be making this amendment.[20]

In the draft decision the AER stated that it would update the roll forward of TransGrid's RAB with the most recent forecast of capex for 2008–09.[21] TransGrid provided an updated capex forecast for 2008–09 in its revised revenue proposal and the AER has accepted this forecast as an input to the RFM.[22]

2.5 AER conclusion

In accordance with schedule 6A.2.3 of the NER, the AER has removed $8.1 million from the RAB to account for replacement assets. The assets, under the unamended clause 11.6.11 of the NER, are properly characterised as providing negotiated transmission services and therefore cannot be included in TransGrid's opening RAB.

Using the updated data for net capex and CPI, the AER's application of the roll forward methodology has determined that TransGrid's opening RAB is $4218 million for the next regulatory control period (as at 1 July 2009). This value is used as an input for the AER's post–tax revenue model for the purposes of determining TransGrid's maximum allowed revenue during the next regulatory control period. The RAB roll forward calculations are set out in table 2.2.

20 TransGrid, *Revised revenue proposal*, p. 11.

21 AER, *Draft decision*, p. 12.

22 To the extent that actual capex differs from forecast capex for the final year of the current regulatory control period, a reconciliation will be undertaken using the actual values as part of the asset base roll forward process at the next transmission determination, in accordance with the NER.

Table 2.2: AER conclusion on TransGrid's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08	2008–09[a]
Opening RAB	3012.8	3103.9	3228.8	3397.9	3735.3
Actual net capex (adjusted for actual CPI and WACC)[b]	134.0	154.1	221.2	331.7	574.9
CPI adjustment on opening RAB	71.1	92.6	78.6	144.1	92.1
Straight-line depreciation (adjusted for actual CPI)	–113.9	–121.7	–130.8	–138.4	–155.3
Closing RAB	3103.9	3228.8	3397.9	3735.3	4247.0
Adjustment for difference between actual and forecast capex for 2003–04					–13.5
Adjustment for return on difference[c]					–7.8
Adjustment for connection assets providing negotiated transmission services					–8.1
Opening RAB at 1 July 2009					4217.5

(a) Updated with the actual CPI for 2008–09 (March to March). Based on updated net capex forecast.

(b) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.

(c) This relates to the difference between actual and forecast capex of $13.5 million for 1 July 2003 to 30 June 2004.

3 Forecast capital expenditure

3.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on forecast capex, including matters raised by TransGrid in its revised revenue proposal.

3.2 AER draft decision

The AER was not satisfied that the capex proposed by TransGrid in its revenue proposal reasonably reflected the capex criteria set out in the NER, taking into account the capex factors. Accordingly, the AER did not accept the forecast capex in TransGrid's revenue proposal.

The AER formed its conclusion based on its own analysis and PB's assessment of a sample of TransGrid's network and non-network projects, its replacement capex program and its project costing and escalation processes.

PB's assessment determined that while TransGrid generally operates consistent with good industry practice in terms of corporate governance and project delivery, there were weaknesses with respect to its assessment of project options and the assessment of project risks. The AER undertook its own analysis of TransGrid's unit cost escalators and assessed them as not being reflective of efficient costs.

On the basis of its analysis and the advice of PB, the AER reduced the capex allowance proposed by TransGrid by $173 million ($2007–08). In addition, the AER approved an indicative contingent projects allowance of $1.2 billion. Table 3.1 sets out the AER's conclusions on the capex allowance proposed by TransGrid.

Table 3.1: AER draft decision on TransGrid's capex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's updated proposal	531.9	465.9	579.2	552.3	420.6	2549.8
Adjustments resulting from detailed project review	3.2	–14.0	–15.4	–19.7	–31.4	–77.2
Replacement programs	–0.8	–2.0	–1.0	–0.9	–0.9	–5.6
Adjustment to cost accumulation process	–6.4	–9.1	–12.6	–16.9	–15.0	–59.9
Application of annual escalators	0.6	–0.1	–6.3	–2.4	3.5	–4.7
Adjustment to cost estimation risk factor	–2.3	–2.0	–2.6	–2.5	–1.8	–11.4
Agreed adjustments (not included in TransGrid's updated proposal)	–0.2	–0.2	–0.4	–0.2	¬0.3	–1.2
Cost estimating factors adjustment	–2.8	–2.4	–3.0	–2.9	–2.2	–13.3
Total adjustments	–8.7	–29.4	–41.1	–45.6	–48.1	–173.3
AER total capex allowance	523.5	436.1	538.1	506.5	372.4	2376.5

Source: AER, *Draft decision*, p. 87.

3.3 Revised revenue proposal

TransGrid's revised revenue proposal included a capex allowance of $2.5 billion ($2007–08). Its updated and revised capex proposals are set out in table 3.2.[23]

Table 3.2: TransGrid's updated and revised capex proposals ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Updated proposed capex[a]	531.9	465.9	579.2	552.3	420.6	2549.8
Revised proposed capex	530.2	460.1	585.3	536.0	403.9	2515.5

Sources: TransGrid, *Updated revenue proposal*, Pro-forma statements and TransGrid, *Revised revenue proposal*, p. 46.
Note: Totals may not add up due to rounding.

TransGrid implemented the draft decision in respect of forecast capex except in regard to:[24]

- the Dumaresq−Lismore 330 kV line project
- the Cooma 132 kV substation replacement project

23 TransGrid's revenue proposal represents what is referred to as the updated revenue proposal in the draft decision. That is, the updated proposed capex detailed in table 3.2 represents the revenue proposal TransGrid submitted to the AER following the release of the 2008 *Annual planning report*.
24 TransGrid, *Revised revenue proposal*, p. 5.

- the Beaconsfield West 132 kV gas insulated switchgear (GIS) replacement project
- the instrument transformer replacement program
- the value and application of project cost estimating factors
- the value and application of cost escalations
- cost estimation risk factors
- contingent projects.

TransGrid also proposed the inclusion of one additional project in its ex ante allowance—the Williamsdale stage 2 project—which was submitted as a contingent project in its revenue proposal.[25]

TransGrid's revised revenue proposal included 15 contingent projects. The total indicative cost for these projects is $1.9 billion.[26]

3.4 Submissions

The AER received submissions commenting on the draft decision and TransGrid's revised revenue proposal from:

- Powerlink
- EnergyAustralia
- TransGrid (three submissions)
- The Energy Users Association of Australia (EUAA).

The main issues raised were in relation to:

- uncertainty and the changing economic environment and its impact on TransGrid's proposed capex program, including its cost escalators and deliverability
- the cost estimation risk factor
- option analysis and the use of engineering judgement
- contingent projects.

3.5 Consultant review

The AER engaged PB to review the additional information provided by TransGrid in its revised revenue proposal. Specifically, it was engaged to review:

- the Dumaresq−Lismore 330 kV line project costs
- the Cooma 132 kV substation replacement project costs
- the Beaconsfield West 132 kV GIS replacement project costs
- the Williamsdale substation stage 2 project costs
- the instrument transformer replacement program costs

[25] TransGrid, *Revised revenue proposal*, p. 5.
[26] TransGrid, *Revised revenue proposal*, pp. 42–45.

- scoping factors costs
- the application of yearly weighting of escalators
- the application of cost estimation risk factors
- contingent projects.

3.6 Issues and AER considerations

3.6.1 Deliverability of the capex program

In the draft decision, the AER noted the instability in world financial markets and that TransGrid was likely to be well positioned to deliver its capex program, even if the global financial crisis continued.[27]

The EUAA noted, however, that there was considerable risk to the delivery of any large capex program, due to current economic uncertainty.[28]

To address concerns about TransGrid's capacity to deliver its capex program, the AER sought clarification from TransGrid regarding any matters and circumstances that may affect its ability to obtain finance to deliver the capex programs it proposed for the next regulatory control period. In response, TransGrid indicated that the NSW Treasury Corporation had advised it that:[29]

> … it has been able to maintain access to funding in order to meet the refinancing needs of the existing debt portfolio and future borrowing needs to finance TransGrid's capital expenditure programme.

The AER also notes that the Australian Government recently recognised (25 March 2009) that state government bond markets have been hit hard by the global financial crisis and that this has threatened the capacity of state and territory governments to deliver projects. The AER further notes that the Australian Government has announced a time-limited, voluntary guarantee over state government borrowing to ensure that this does not occur.[30]

Based on the information detailed above, the AER considers that TransGrid remains in a good position to obtain the necessary finance to deliver the capex it has proposed for the next regulatory control period.

3.6.2 Growth and demand forecasts

The AER notes that Country Energy, EnergyAustralia and Integral Energy (the NSW DNSPs) revised downward their proposed capex programs in their revised regulatory proposals in light of the:[31]

- anticipated impacts on peak demand of the worsening global financial crisis

---

27 AER, *Draft decision*, p. 85.

28 EUAA, *Submission on the AER Draft decision on TransGrid's transmission revenue proposal & TransGrid's revised revenue proposal*, 20 February 2009, p. 11.

29 TransGrid, *Response to information request number 304*, 27 February 2009.

30 Treasurer of the Commonwealth of Australia, Press release No. 27, *Temporary guarantee of state borrowing*, 25 March 2009.

31 AER, *Final decision, New South Wales distribution determination, 2009–10 to 2013–14*, 28 April 2009, section 7.3.

- release of the Australian Government's carbon pollution reduction scheme (CPRS) white paper.

On 6 February 2009, the AER sought information from TransGrid regarding how the revisions to the NSW DNSPs' maximum demand forecasts would affect its proposed capex program. TransGrid responded and noted:[32]

> The revised NSW Distributor and ActewAGL global forecasts have been reviewed by TransGrid. Based on the information contained in the revised revenue [regulatory] proposals, along with additional information provided by EnergyAustralia and Integral Energy, TransGrid has determined that there will be no impact on the capital program within the 2009–2014 regulatory control period.

The AER notes that the timing of proposed capex can limit the ability of a TNSP to defer projects and programs. This is particularly the case where contracts have been established for work within the first few years of the next regulatory control period. The AER considers that any significant deferrals would be expected to occur from the middle of the next regulatory control period, for projects that are currently being planned, and the need for which is still being assessed. This was, for example, seen when TransGrid updated its revenue proposal, prior to the release of the draft decision, to reflect its *2008 Annual planning report*.[33]

The AER also considers that there is not a linear relationship between short–term changes in maximum demand and planned growth capex. The relationship between these factors varies over time.

Based on the information provided by TransGrid, the AER considers TransGrid has adequately considered how changing maximum demand in NSW will impact its proposed capex program.

3.6.3 Dumaresq–Lismore line augmentation project

This project relates to installing an additional 330 kV transmission line from Dumaresq to Lismore by 2012 to meet growing demand in the far north coast of NSW and address corresponding voltage and line loading limitations.

AER draft decision

In the draft decision, the AER was not satisfied that TransGrid had estimated the capex associated with this project based on what a prudent operator in TransGrid's circumstances would incur and that it did not reasonably reflect the capex criteria. Concerns with TransGrid's proposal included:[34]

- double counting of a $22 million easement
- insufficient justification for the number of 330 kV circuit breakers proposed for the Dumaresq substation
- lack of transparency in the application of the 'scoping cost factor on line works'
- an unreasonably high CPI adjustment (10.1 per cent) in its modelling.

---

32 TransGrid, *Response to issue 308*, 27 February 2009, p. 4.

33 PB, *TransGrid revenue reset, APR 2008 supplementary report*, 12 Noveber 2008.

34 AER, *Draft decision*, pp. 51–52.

The AER considered that an allowance of $129 million ($2007–08) for the project—a reduction of $36 million—was reflective of the costs which a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives in accordance with the capex criteria.[35]

Revised revenue proposal

TransGrid did not accept the AER's reduced allowance for this project and proposed a revised cost estimate of $162 million.[36]

TransGrid stated that one of the two circuit breakers removed in the draft decision was required to, among other matters, increase the quality, reliability and security of supply. It stated that the cost of reintroducing an additional centre circuit breaker to the project was $1.3 million.[37]

TransGrid also stated that the reductions associated with the application of too high a scoping cost factor and on cost escalation during the cost estimation process should be reinstated. It noted its application of cost escalation was lower than that applied by the AER in the draft decision and that the scoping cost factor was equivalent to the standard cost factor used and accepted by the AER—ancillary works factor[38]—in projects of this type.[39]

TransGrid accepted it had double counted a $22 million easement in the project and submitted it had adjusted its capex accordingly.[40]

Submissions

Powerlink stated that the AER had criticised TransGrid on its reliance on engineering judgement to inform its decisions. Specifically, it stated:[41]

- engineering judgement was an important and necessary tool in option analysis
- it would be impractical, time consuming and inefficient for a TNSP, during the preliminary stages of an assessment, to undertake detailed estimates and full scale assessment of every option to address an identified network need.

The EUAA noted a generic concern with TransGrid's option analysis and its application of engineering judgement. Specifically, it stated that:[42]

---

35 AER, *Draft decision*, pp. 51–52.

36 TransGrid, *Revised revenue proposal*, p. 21.

37 TransGrid, *Revised revenue proposal*, p. 17.

38 The ancillary works factor is used to account for the minor project costs that are not captured by the high level scoping carried out during the concept phase of a project. Costs captured by this factor include the costs of integrating the new project into the existing network, changes to control and protection systems, and ancillary/incidental works that occur during the construction period, which are covered by schedule of rates allowances within the construction contract.

39 TransGrid, *Revised revenue proposal*, pp. 20–21.

40 TransGrid, *Revised revenue proposal*, p. 20.

41 Powerlink, *Draft decision, TransGrid Transmission determination 2009–10 to 2013–14*, 16 February 2009, pp. 1–2.

42 EUAA, pp. 8–9. This concern is applicable to all revised projects. The AER notes that it has assessed the reasonableness of a sample of the capex projects included in TransGrid's original and revised revenue proposals to determine if they are prudent and efficient and reasonably reflect the capex criteria, including the capex objectives.

- the AER's concern regarding engineering judgement and option analysis were important and should not be dismissed
- further analysis needed to be undertaken to demonstrate the robustness of the options selected for inclusion in TransGrid's capex allowance.

TransGrid, in its own submission to the AER, noted that with respect to option analysis and its application of engineering judgement:[43]

- there is always room for improvement
- PB found (in reference to its initial proposal), that 'overall, it was satisfied that the process used by TransGrid to determine project costs was reasonable'.

Consultant review

PB determined the reinstatement of a ($1.3 million) centre circuit breaker for this project would maintain reliability and operational flexibility at Dumaresq as well as avoid transmission constraints during maintenance activities at the site.[44]

PB considered that TransGrid had not demonstrated that the application of a 15 per cent scoping cost factor was either transparent or reasonable. It retained its recommendation for the scoping cost factor to be set at 10 per cent as:[45]

- 42 per cent of the proposed route was on a greenfield corridor, where a 10 per cent standard ancillary works factor should be applied
- the original cost was based on the 'longest probable feasible route', and that would tend to overstate the scope and cost of the project.

PB also considered that TransGrid had not demonstrated that its proposed cost escalation adjustment was reasonable. It retained its recommendation that a $7.4 million adjustment be made to TransGrid's capex as:[46]

- the estimate and escalation process applied in this project was outside TransGrid's normal processes, as the estimating process it had used had been superseded
- the non–standard process adopted by TransGrid included an allowance for real escalation of input costs based on recent experience
- the project was already a committed project at the time of inclusion in the forward capex allowance.

PB reviewed TransGrid's capital accumulation model and determined that it had removed the $22 million easement double count from its modelling.[47]

PB concluded that TransGrid had not demonstrated its proposal was reflective of a prudent and efficient TNSP. It recommended an $11 million reduction in TransGrid's revised capex allowance.[48]

---

43 TransGrid, *Submission to the AER on EUAA comments*, p. 2.
44 PB, *TransGrid revised revenue proposal, An independent review*, pp. 12–13.
45 PB, pp. 13–14.
46 PB, p. 15.
47 PB, p. 14.

AER considerations

The AER notes, based on the evidence presented by TransGrid, PB's analysis and its own analysis, that TransGrid has removed the double counting associated with the $22 million easement.

The AER agrees with PB's advice that TransGrid has demonstrated that an additional 330 kV centre circuit breaker for this project is required in the next regulatory control period. The AER considers this circuit breaker is required to maintain the reliability and operational flexibility currently available at Dumaresq. On this basis, the AER endorses PB's recommendation to reinstate $1.3 million to the capex allowance.

The AER notes PB's concern with the scoping cost factor and accepts PB's recommendation that this be reduced to 10 per cent to reflect an efficient scoping allowance. The AER considers the $4.0 million reduction associated with this amendment is appropriate, as the scope of this project is relatively well known.

The AER also agrees with PB's analysis that TransGrid has applied an inflation adjustment that is too high. The AER considers that it is reasonable to use an inflation rate of 6.2 per cent to escalate the original cost and endorses PB's recommendation to remove $7.4 million from the proposed capex allowance.

The AER notes Powelink's and the EUAA's concerns regarding engineering judgement and option analysis and notes that in the draft decision it highlighted that:[49]

- it did not have concerns with the use of engineering judgement per se
- it did have concerns with engineering judgment where it was not applied in a clear, transparent and documented manner.

The AER considers that it is not unreasonable to expect that where engineering judgement is exercised that an informed third party should be able to consider the factors underpinning that judgement.

Similarly, the AER does not consider it unreasonable that where a TNSP is proposing to spend millions, often hundreds of millions, of dollars on a project that robust options analysis and net present value analysis is used to help inform its decision, even at early stages of a project's development.[50] The AER considers that the application of these tools:

- facilitates prudent and efficient investment decisions
- should, where practical and where a project is material, be a standard component of the decision making process.

For the reasons discussed above and as a result of the AER's analysis of TransGrid's revised revenue proposal, the AER is not satisfied that TransGrid's capex proposal reasonably reflects the capex criteria, including the capex objectives. It considers that an

---

48 PB, p. 15.

49 AER, *Draft decision*, p. 237.

50 The AER also recognises that factors outside of NPV assessments can inform investment decisions. However, where this is the case, these factors need to be rigorously and systematically examined. Source: AER, *Draft decision*, p. 226.

allowance of $151 million ($2007–08) for this project—a reduction of $11 million[51]—reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

3.6.4 Cooma 132 kV substation replacement project

This project relates to the replacement of the Cooma 132 kV substation on a new site by 2014 due to its poor condition and concerns with the arrangement of the substation.[52]

AER draft decision

The AER was not satisfied that the capex associated with this project reasonably reflected the capex criteria. The AER considered the most efficient option had not been selected and that refurbishment of the substation on the existing site (without busbar works), was reflective of the costs that a prudent and efficient TNSP in TransGrid's circumstances would incur.[53]

The AER considered an allowance of $25 million ($2007–08) for the project—a reduction of $18 million—reflected the costs that a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives in accordance with the capex criteria.[54]

Revised revenue proposal

TransGrid did not accept the AER's reduced allowance for this project and proposed a revised cost estimate of $35 million. It considered the reduced allowance did not reflect the costs that a prudent TNSP operating in similar circumstances to itself would need to achieve the capex objectives.[55]

TransGrid, with assistance from Sinclair Knight Merz Pty Ltd (SKM), developed new cost estimates for the options associated with this project. Based on the new cost estimates, TransGrid stated that a 'greenfield' redevelopment at Cooma North was a prudent and efficient option (and that this could be achieved at a cost $8.1 million lower than that proposed in its revenue proposal). It noted that the option it selected did not have the highest net present value (NPV) but that it facilitated future development, eliminated line congestion around the existing Cooma substation and minimised the longer term impact on the community.[56]

Consultant review

PB reviewed TransGrid's revised revenue proposal and was not satisfied that the revised option estimates were reasonable. It was concerned with TransGrid's reliance on general and non-standard scoping factors and inconsistencies in their application. Specifically, it

---

51 The AER notes that amendments to risk and escalation adjustments detailed in this review also impact this project. The total adjustment is $12.7 million. It also notes that the recommended adjustments proposed by PB are consistent with TransGrid's approach for a committed project—that is, PB's adjustments do not include risk and escalation allowances. Source: PB, p. 15.

52 AER, *Draft decision*, p. 54.

53 AER, *Draft decision*, p. 54.

54 AER, *Draft decision*, p. 54.

55 TransGrid, *Revised revenue proposal*, p. 25.

56 TransGrid, *Revised revenue proposal*, pp. 24–25.

considered TransGrid's estimates may have double counted 'brownfield'[57] factors during its estimation process as:[58]

- the application of non-standard factors remained arbitrary and lacked transparency
- the non–standard factors applied were applied to base estimates that appeared to have already accounted, to some degree, brownfield issues
- the project was not a pure brownfield site—there were greenfield components.

PB recognised that some form of non-standard factor application was appropriate and considered that the 23 per cent[59] brownfield factor determined by SKM for SP AusNet's recent revenue proposal provided a reasonable basis for this factor.[60]

PB re-estimated the costs of the options associated with this project and determined that the most efficient option was the in-situ replacement (excluding busbars) option.

PB also considered that full consideration had not been given to the refurbishment of the transformers by TransGrid and that no further evidence had been submitted to demonstrate consideration of the potential management options for the existing Cooma transformers.[61]

PB also adjusted TransGrid's proposed capex ($1.6 million) to reflect the release of a transformer at Cooma, which was in serviceable condition, for use on another project.[62]

PB concluded that an $18 million reduction to the capex associated with project was appropriate.[63]

AER considerations

The AER reviewed TransGrid's revised documentation and PB's analysis, and agrees with PB's position that there are concerns with TransGrid's option analysis. Specifically, the AER considers TransGrid has, when developing its options, relied on general and non–standard scoping factors and that there are inconsistencies in their application. The AER also notes that the options identified to address this identified need are highly sensitive to input assumptions regarding the application of scoping factors and brownfield adjustments.

Regarding TransGrid's assessment of options, the AER recognises there are factors that increase the risk and complexity of this project, and that these factors are valid in informing investment decisions. However, such factors need to be rigorously and systematically examined, transparent and justified. The AER considers that these

57 Brownfield factors are factors associated with the complexities associated with building on an existing site, where there is often increased complexity and risk. This issues is also known as the 'in–situ replacement factor', see section 3.6.5.

58 PB, pp. 18–20.

59 The 23 per cent brownfield factor was determined by SKM for work on SP AusNet's 132 kV switchbays, which was a material issue given the nature of the replacement works undertaken by SP AusNet at its existing sites. Source: PB, p. 20.

60 PB, p. 20.

61 PB, p. 2.

62 PB, p. 2.

63 PB, p. 24.

conditions have not been met with regard to this project and agrees with PB's analysis that the application of non-standard factors appears arbitrary and lacks transparency.

The AER considers TransGrid's assessment of this particular project does not demonstrate that the option chosen reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, as required by clause 6A.6.7(c) of the NER.[64]

The AER concludes that the option that reasonably reflects the efficient costs a prudent TNSP in TransGrid's circumstances would incur to achieve the capex objectives is the in–situ replacement (excluding busbars) option.

The AER also considers that TransGrid's revised submission did not provide any new evidence to demonstrate that it had considered potential management options for the Cooma transformers. The AER agrees with PB's analysis that there is scope for a transformer associated with this project to be re-used. As a result, the AER considers that PB's recommended $1.6 million adjustment to reflect the avoided cost of procuring a 132/66 kV transformer for a separate project is reasonable.

For the reasons discussed above and as a result of the AER's analysis of TransGrid's revised revenue proposal, the AER is not satisfied that TransGrid's capex proposal reasonably reflects the capex criteria, including the capex objectives. The AER considers that an allowance of $23 million ($2007–08) for this project—a reduction of $18 million[65]—reasonably reflects the capex criteria, including the capex objectives. In reaching this view, the AER has had regard to the capex factors.

3.6.5 Beaconsfield West 132 kV gas insulated switchgear replacement project

This project involves the replacement of the 132 kV GIS at Beaconsfield West due to it approaching the end of its serviceable life.[66]

AER draft decision

In the draft decision, the AER was not satisfied that the capex associated with this project reasonably reflected the costs a prudent TNSP in TransGrid's circumstances would require, and did not reflect the capex criteria.

Specifically, the AER considered there was a lack of transparency and justification for the application of certain cost factors—the design cost factor[67], network cost factor[68], and construction costs—associated with the project.[69]

---

64 Concerns associated with the application of non–standard scoping factors are also discussed in section 3.6.5.

65 This reduction includes an adjustment to take account of risk and escalation adjustments. Source: PB, p. 24.

66 AER, *Draft decision*, p. 55.

67 The design cost factor includes all costs associated with the design, specification preparation, tendering process, the environmental assessment and the project management of the project. It is calculated as a percentage cost of the overall capital cost of the project and is varied according to the type of project being undertaken.

The AER considered that an allowance of $40 million ($2007–08) for the project—a reduction of $8.1 million—was reflective of the costs that a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives in accordance with the capex criteria.[70]

Revised revenue proposal

TransGrid did not accept the AER's reduced allowance for this project and proposed a revised cost estimate of $44 million (or $51 million inclusive of risk and cost escalations).[71]

TransGrid stated that subsequent to the release of the draft decision it engaged SKM to provide an independent assessment of the cost factors it had used to estimate the cost of this project. It noted SKM's findings that:[72]

> … it is reasonable for TransGrid to use non-standard cost factor allocation for the project. Given the nature of, and the complexities with the Beaconsfield West Project, SKM considers the cost factor allocation used by TransGrid to be below that typically required for undertaking such a project.

TransGrid resubmitted that the application of non-standard cost factors was appropriate and reiterated the conservative nature of the factors it had applied. The cost factors adopted in its revised revenue proposal were:[73]

- network cost factor—15 per cent
- design cost factor—10 per cent
- ancillary works factor—15 per cent
- in–situ replacement factor—30 per cent.

Consultant review

PB highlighted that the use of non-standard cost factors for estimating project costs was often appropriate but noted that where this occurred, the rationale for the magnitude of these factors had to be clear and justifiable.[74]

PB considered SKM's analysis had not demonstrated the basis for the 30 per cent in–situ replacement factor and that this figure appeared arbitrary. It stated SKM's analysis had only demonstrated how acceptance of this escalator would impact on various aspects of the cost estimate.[75]

---

68 The network cost factor includes all the costs associated with field supervision, site management and commissioning of the project. This cost factor is calculated as a percentage cost of the overall capital cost of the project and is varied according to the type of project being undertaken.

69 AER, *Draft decision*, p. 55.

70 AER, *Draft decision*, pp. 55–56.

71 TransGrid, *Revised revenue proposal*, p. 28.

72 TransGrid, *Revised revenue proposal*, p. 28.

73 TransGrid, *Revised revenue proposal*, p. 28.

74 PB, pp. 26–30.

75 PB, pp. 27–28.

PB acknowledged that the examples[76] cited by SKM, and used by TransGrid, to support their analysis provided some insight into the risk and complexities of this project but noted that TransGrid had not demonstrated the cost of managing the costs and complexities of this site.[77] It also noted that:[78]

- the 30 per cent in–situ factor proposed by SKM was generic and remained largely unsubstantiated
- SKM's application of this factor appeared to double count the brownfield adjustments applied in TransGrid's standard augmentation factors.

To address its concern, PB applied the approach it adopted in assessing the Cooma substation replacement project (section 3.6.4) and re–estimated the cost estimates associated with this project.[79]

PB recommended that TransGrid's revised revenue proposal for this project be reduced by $6.1 million.[80]

AER considerations

The AER has reviewed TransGrid's documentation and PB's analysis, and has undertaken its own analysis. It agrees with PB's advice that TransGrid has not reasonably demonstrated the basis for the 30 per cent in–situ replacement factor, and that this figure appears arbitrary. Specifically, the AER notes that while TransGrid has provided additional information to support how it has applied this factor, it has not sufficiently demonstrated the cost of managing these issues.

The AER accepts PB's advice that a figure of 23 per cent for in–situ project cost adjustment is appropriate. The AER considers that in the absence of information historical data from TransGrid, the analysis undertaken by SKM for SP AusNet should be applied, as it is transparent and can be justified.

The AER also considers that this project is not a pure brownfield site and that some aspects of the proposed costs have previously been adjusted to reflect the complex nature of the work that is to be undertaken. The AER notes that:

- much of work to be undertaken will take place in a new building, thereby reducing the complexity of this project
- the brownfield allowances made in the base estimates were compounded by the in–situ factor and that this may result in the cost estimates for this project being overstated.

Accordingly, the AER agrees with the proposed amendments put forward by PB regarding the application of the scoping factors and has made a corresponding reduction to TransGrid's capex allowance.

---

76 Examples highlighted by TransGrid and SKM included an in situ replacement project in Zurich and an informal briefing from a substation contractor regarding in situ rebuild costs. Source: PB, pp. 27–28.

77 PB, pp. 27–28.

78 PB, p. 30.

79 PB, pp. 29–30.

80 PB, p. 30.

For the reasons discussed above and as a result of the AER's analysis of the revised revenue proposal, the AER is not satisfied that TransGrid's capex proposal reasonably reflects the capex criteria, including the capex objectives. The AER considers that an allowance of $44 million ($2007–08) for this project—a reduction of $7 million[81]—reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

3.6.6 Williamsdale 330 kV substation stage 2 project

This project involves the establishment of a second supply point for the ACT with a capacity of at least 375 MVA. This project has to be completed by June 2012 to meet the obligations of the ACT's reliability criteria.[82], [83]

AER draft decision

The Williamsdale 330 kV substation stage 2 project was a proposed contingent project in TransGrid's revenue proposal. The AER did not accept this project as a contingent project in the draft decision, due to concerns with the project scope and trigger, but noted:[84]

> To the extent that the underlying need for the investment already exists, TransGrid may wish to consider the appropriateness of this project as part of its capex allowance.

Revised revenue proposal

TransGrid stated that since it lodged its revenue proposal in May 2008 it had resolved the planning and approval uncertainties associated with stage one of this project. Consequently, to meet the ACT's 2012 reliability criteria,[85] it stated that stage two of this project should be included as part of its ex ante capex for the next regulatory control period.[86]

The project has a proposed commissioning date of June 2012 and a proposed cost of $35 million ($2007–08).[87]

TransGrid's documentation on this project included options and costing on how to proceed, namely:[88]

- Bungendore–Williamsdale 330 kV line
- Wallaroo switching station
- Yass–Williamsdale single circuit 330 kV line
- Yass–Canberra/Williamsdale double circuit 330 kV line.

81 This adjustment includes risk and escalations. Source: PB, p. 30.
82 TransGrid, *Revised revenue proposal*, p. 28.
83 The network service criteria applying to TransGrid in the ACT is contained in the Utilities Exemption 2006 (No 1) under the *Utilities Act* 2000.
84 TransGrid, *Revised revenue proposal*, p. 29.
85 The next stage of the ACT's reliability criteria applies from 1 July 2012 and requires TransGrid to provide a 330 kV supply that is independent of the Canberra 330/132 kV substation.
86 TransGrid, *Revised revenue proposal*, p. 29.
87 TransGrid, *Revised revenue proposal*, p. 30.
88 TransGrid, *Revised revenue proposal*, p. 29.

TransGrid stated that the Wallaroo switching station was its preferred option as it was the most efficient option to meet the obligations of the ACT's reliability criteria.[89]

Consultant review

PB undertook a detailed review of TransGrid's documentation relating to this project and considered that the drivers and strategic alignment of the project to be prudent, and that a reasonable range of options were considered.[90]

PB noted the project was in alignment with TransGrid's policies and strategies as stated in its *Strategic network development plan* and the *Outline plan for the area*.[91]

PB also noted that:[92]

- six options were presented for consideration
- two options were excluded on technical and environmental considerations
- four options were subject to NPV analysis.

TransGrid's NPV analysis of the feasible options is set out in table 3.3.

Table 3.3: NPVs of Williamsdale 300 kV substation stage 2 options ($m)

Option	Estimate	NPV
Bungendore–Williamsdale 330 kV line (option A)	$84 to $106	–$47 to –$59
Wallaroo switching station (option B)	$35	–$20
Yass–Williamsdale single circuit 330 kV line (option C)	$57	–$31
Yass–Canberra/Williamsdale double circuit 330 kV line (option D)	$70	–$38

Source: PB, p. 32.

Based on TransGrid's costing and documentation, PB considered the most efficient option was option B, the provision of the Wallaroo switching station.[93]

PB also considered that TransGrid had incorrectly included a $0.85 million risk allowance into its base estimate to cover land acquisition. It considered that a provision for risk was provided at the portfolio level and that a further allowance at the project level was not appropriate.[94]

89 TransGrid, *Revised revenue proposal*, p. 29.
90 PB, pp. 31–34.
91 PB, p. A14.
92 PB, pp. A14–A15.
93 PB, pp. A15–A16.
94 PB, pp. 33–34.

AER considerations

The AER has reviewed TransGrid's documentation and PB's analysis and considers that TransGrid has identified the need to establish a second supply point for the ACT to meet the obligations of that jurisdiction's reliability criteria.

The AER notes that TransGrid identified and considered a range of practical alternatives to meet the reliability criteria required and that of all the options considered the Wallaroo switching station option was the most preferred.

Based on the material presented by TransGrid, PB's analysis and its own analysis, the AER considers the establishment of the Wallaroo switching station is reasonable and represents a prudent and efficient option. This determination has been reached following careful consideration of the feasible options and the legal requirement to meet this identified need.

Regarding TransGrid's risk allowance, the AER notes PB's concerns with TransGrid's application of risk and its $0.85 million adjustment. The AER considers that TransGrid should adhere to established cost estimating processes, and notes this risk adjustment appears to be inconsistent with TransGrid's processes. However, the AER, based on the analysis undertaken to date, including the projects subject to detailed review by PB, does not consider this project to be representative of a systemic issue across TransGrid's capex program. Therefore, while the AER considers TransGrid's forecast capex for this project may be on the high side, and the estimating procedures followed for this project could be improved, the overall forecast is not unreasonable. Consequently, the AER will not make any adjustment to TransGrid's forecast capex allowance for this project.

For the reasons discussed above and as a result of the AER's analysis of the revised revenue proposal, the AER is satisfied that TransGrid's capex proposal of $35 million ($2007–08)[95] reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

3.6.7 Extension of findings on detailed sample project reviews to remainder of the forecast capex allowance

AER draft decision

In the draft decision, the AER was not satisfied that TransGrid's application of scoping factors to the project estimation process reflected costs a prudent TNSP in TransGrid's circumstances would require, and that it did not reasonably reflect the capex criteria. Specifically, the AER found:[96]

- unjustified adjustments of standard cost factors was a systematic concern
- a lack of transparency in the application of the design cost factor and network cost factor.

95 This amount includes additional risk and escalation allowances. Source: PB, p. 34.
96 AER, *Draft decision*, pp. 61–62.

The AER considered that a reduction of $13 million ($2007–08) to the capex allowance was reflective of the costs which a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives in accordance with the capex criteria.[97]

Revised revenue proposal

TransGrid rejected the AER's finding that its cost estimation process led to a systematic over estimation of capex project costings. It submitted that the $13 million reduction applied by the AER should be reinstated, as it had reviewed and adjusted its capex program so only four projects remained with discretionary cost factor adjustments.[98]

TransGrid also stated that:[99]

- not all projects can be fitted into a standard cost estimating process and that the estimating process requires flexibility
- the non–standard cost factors used in costing the Beaconsfield West project (section 3.6.3) were amended in its revised revenue proposal.

Submissions

The EUAA noted the AER's concerns with the application of scoping factors and highlighted that these concerns affected the AER's ability to determine if a proposal was prudent and efficient. It noted that these findings should not be dismissed and should not be assumed to be minor.[100]

TransGrid highlighted that PB had indicated that 'overall, it was satisfied that the process TransGrid had used to determine project costs was reasonable'. It also reiterated the steps it had taken in its revised revenue proposal to address the concerns raised in the draft decision.[101]

Consultant review

PB noted that it was not concerned with the use of non-standard cost factors per se, but with the justification of the value of the cost factors applied.[102]

PB accepted that TransGrid had systematically reviewed its project portfolio and found that the application of non–standard factors was limited to 6 per cent of the projects detailed in its forward capital works program. However, it was concerned that TransGrid's review was limited in scope, as it failed to consider the non–preferred options used in the selection process for each project.[103]

PB considered that the application of non-standard factors remained a procedural issue within TransGrid's cost estimating process and recommended that an adjustment be retained as a proxy for likely inefficiency in the option analysis process.[104]

97 AER, *Draft decision*, p. 62.
98 TransGrid, *Revised revenue proposal*, p. 35.
99 TransGrid, *Revised revenue proposal*, p. 34.
100 EUAA, p. 9.
101 TransGrid, *Response to the AER on EUAA comments*, 16 February 2009, p. 2.
102 PB, pp. 39–40.
103 PB, pp. 40–41.
104 PB, pp. 40–40.

As per the draft report, PB considered that the review of the Beaconsfield West 132 kV GIS replacement project (section 3.6.5) would permit it to assess the application of these factors and estimate the likely systemic cost. Consequently, it recommended a $3.4 million correction to account for costs associated with the application of the design cost factor and network cost factor that were not adequately justified. The $3.4 million correction represented 0.39 per cent of the value of the reviewed projects ($943 million, including the additional Williamsdale substation stage 2 project).[105]

PB found that if the Beaconsfield West project derived 0.39 per cent adjustment were applied on a pro-rata basis across the un–reviewed capital works portfolio of TransGrid's revised capex proposal, a correction of $5.1 million was warranted.[106]

AER considerations

The AER considers that the sample of TransGrid's projects subject to detailed review is representative of the total forecast capex program and is indicative of the issues likely to be encountered across TransGrid's entire proposed forecast capex allowance. This provides the basis for making a 'top down' adjustment that the AER considers is appropriate in determining whether it is satisfied on the whole that TransGrid's proposed forecast capex allowance reasonably reflects the capex criteria, taking into account the capex criteria.

The AER agrees with PB's analysis that there is a procedural issue within TransGrid's cost estimating process and that an adjustment be retained as a proxy for the inefficiency in the option analysis process. The AER also agrees with the EUAA that this issue is not minor and should not be dismissed.

The AER notes that TransGrid reviewed the application of scoping factors on its preferred options but also notes that this review did not cover all the options considered as part of the investment decision process. The AER considers that as non–preferred options were not considered as part of this review there is scope for the most efficient option not to have been selected, and that an adjustment to reflect this inefficiency is reasonable.

The AER notes that PB has not adjusted the majority of the other projects subject to detailed project review, but that PB's detailed review of the other projects did permit it to assess the overarching cost efficiency of those projects and recommend appropriate 'bottom up' adjustments. This explains why PB's extrapolation of the scoping factor is applied only to unreviewed capex projects. The AER considers that the approach PB has adopted in extending the findings of the detailed sample project reviews to the remainder of the forecast capex allowance is reasonable.

For the reasons discussed above and as a result of the AER's analysis of TransGrid's revised revenue proposal, the AER is not satisfied that TransGrid's capex proposal reasonably reflects the capex criteria, including the capex objectives. The AER considers that a reduction of $5.1 million ($2007–08) reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

105 PB, p. 41.
106 PB, p. 41.

3.6.8 Replacement projects

AER draft decision

In the draft decision, the AER was not satisfied that the capex associated with TransGrid's replacement projects reasonably reflected the costs a prudent TNSP in TransGrid's circumstances would require, and that it did not reasonably reflect the capex criteria.[107]

The AER considered that a reduction of $4.4 million ($2007–08) for instrument transformers replacement programs, to reflect the capacity for instrument transformers to be reused as part of a regular, rather than emergency, system of replacement was required to achieve the capex objectives, in accordance with the capex criteria.[108]

Revised revenue proposal

TransGrid did not accept the AER's reduced allowance for the instrument transformer replacement programs. It reviewed the instrument transformers nominated for replacement and found there would be:[109]

- insufficient spares suitable for reuse—around 6 per cent of its transformer population was found to be suitable for reuse
- an increased risk of explosion and fire with the reuse of older, high voltage instrument transformers.

TransGrid proposed a revised cost for this program of $15 million ($2007–08).[110]

TransGrid also stated that the cost differences between the options it had considered for this program were small and/or insignificant and that its proposal was not unreasonable.[111]

Consultant review

PB determined there was a significant limitation on the number of instrument transformers suitable for re–use. It agreed that the option to use spare instrument transformers for emergency purposes only should be included in TransGrid's capex allowance.[112]

PB was concerned with a perceived inconsistency surrounding TransGrid's risk assessment for the options considered. It did not consider it reasonable that in the event that an instrument transformer failed there would be increased collateral damage if the instrument transformer was part of a planned, rather than an emergency, replacement program. To address this inconsistency, it considered a $0.2 million adjustment to TransGrid's proposed capex allowance was appropriate.[113]

---

[107] AER, *Draft decision*, p. 62.
[108] This cost was inclusive of escalation AER, *Draft decision*, p. 63.
[109] TransGrid, *Revised revenue proposal*, pp. 33–34.
[110] This cost was exclusive of escalation. Source: TransGrid, *Revised revenue proposal*, p. 31.
[111] TransGrid, *Revised revenue proposal*, p. 34.
[112] PB, pp. 36–38.
[113] PB, pp. 36–38.

PB concluded that $4.0 million of the $4.2 million removed in the draft decision should be reinstated in the final decision.[114]

AER considerations

The AER has reviewed TransGrid's documentation and PB's analysis and considers that TransGrid's revised documentation provides sufficient evidence that supports the relatively limited number of instrument transformer available for re–use. The AER notes that only 6 per cent of instrument transformers covered by this project are likely to potentially suitable for re–use. The AER therefore agrees with TransGrid and PB that there is merit in the use of spare instrument transformers in an emergency replacement program.

The AER notes PB's concerns with TransGrid's risk assessment process and that:

- its options development process could be improved
- there is scope for efficiencies to be captured through more effective risk assessment and application.

Nonetheless, on balance, while the AER considers TransGrid's proposal may be on the high side, its proposal is not unreasonable.

For the reasons discussed above and as a result of the AER's analysis of TransGrid's revised revenue proposal, the AER is satisfied that TransGrid's capex proposal reasonably reflects the capex criteria, including the capex objectives. The AER considers that an allowance of $17 million[115] ($2007–08) for these programs reasonably reflects the capex criteria, including the capex objectives. In reaching this view, the AER has had regard to the capex factors.

3.6.9 Input cost escalators

Labour and materials

AER draft decision

In the draft decision, the AER considered that its conclusions from the recent ElectraNet decision were still applicable with respect to the methodology used for estimating the cost escalators. In most cases, no new and compelling evidence had been presented justifying a departure from the approach it had previously accepted.[116]

The AER considered that given the inherent uncertainties around the existence of and estimation of real movements in producer margins and indirect labour costs further departures from CPI were not warranted. The AER concluded that the inclusion of these factors would weaken the influence of commodities prices and the symmetry of the cost escalators envisaged by it.[117]

[114] PB, pp. 36–38.
[115] This cost is inclusive of escalation. Source: PB, p. 38.
[116] AER, *Draft decision*, pp. 68–69.
[117] AER, *Draft decision*, pp. 68–69.

Revised revenue proposal

TransGrid did not accept the cost escalators applied by the AER in the draft decision. It engaged the Competition Economists Group (CEG)[118] to review the draft decision and, based on that advice, determined that while the AER's approach was reasonable, it had concerns with:[119]

- technical aspects of the AER's modelling, principally timing and the application of lags
- the AER's proposed approach to updating labour cost escalation factors.

TransGrid accepted the AER determined cost escalator for land. Revised escalators were, however, proposed for the majority of the other escalators.

Submissions

The EUAA welcomed the AER's decision to review input costs prior to the final decision.[120]

AER considerations

The AER considers that a number of the improvements suggested by CEG and accepted by TransGrid to improve the AER's approach to cost escalations are reasonable. The AER has updated its approach to reflect a number of these amendments as well as to update for the most recent data and to correct identified errors.

In terms of base metals and crude oil escalators, the AER agrees with TransGrid's revised revenue proposal that adopting a 12 month averaging period for materials escalators for each financial year of the next regulatory control period is reasonable. The AER considers this removes potential price distortions, as it recognises that all equipment is not costed and purchased over a single month but over each financial year of the period.

The AER notes that TransGrid did not apply a lag on its base metal and oil input cost escalators in its revenue proposal but that it accepted the lag inherent in CEG's analysis as part of its revised revenue proposal. The AER considers this represents a change in the methodology that was submitted by TransGrid in its revenue proposal and which was accepted by the AER in the draft decision. The AER also considers that this change was not made to address an issue raised in the draft decision. As such, the AER considers that, under the NER, this change can not be accepted.

The AER acknowledges TransGrid's concerns regarding the sole reliance on one economic forecaster for its labour growth cost and construction cost forecasts. In the draft decision, the AER did not consider the averaging methodology adopted by CEG was appropriate because the Macromonitor and Econtech's electricity, gas and water (EGW) sector labour cost growth and construction cost forecasts were not comparable, and averaging the two forecasts was likely to produce unreliable cost escalation forecasts.[121] For this final decision, the AER maintains its view that it is not satisfied that

---

118 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009.

119 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009 p. 2.

120 EUAA, p. 13.

121 AER, *Draft decision*, p. 253.

Macromonitor provides sufficient explanation surrounding the basis of the model used to derive its forecasts. The AER also notes that Econtech found that upon reviewing CEG's revised escalator report, that it remained difficult to assess the forecast results provided by Macromonitor as no new information pertaining to the methodology have been provided.[122] Further, the AER is satisfied that Econtech's methodology for forecasting labour costs growth is robust given the application of both an economic–wide model and a purpose–built labour cost model.[123]

The AER agrees with TransGrid regarding the need to address potential double counting of inflation when indexing between the TransGrid's enterprise bargaining agreement (the Award)[124] and Econtech wage rates. The AER has therefore amended its approach to labour escalators to reduce the scope for double counting. Issues associated with labour escalators are also discussed in chapter 5 of this final decision.

For the same reasons as discussed for the EGW escalator, the AER considers that reliance on one economic forecaster to determine the construction cost escalator is appropriate.

The AER notes TransGrid's revised revenue proposal accepted the draft decision and removed real cost escalation from the proposed producer's margin and indirect (producer's) labour component of its forecast equipment purchase costs.

More detailed information on the AER's final assessment is set out in appendix A of this final decision. Table 3.4 sets out the AER's conclusions on TransGrid's real cost escalators to apply over the next regulatory control period.

Table 3.4: AER conclusion on TransGrid's real cost escalators to apply during the next regulatory control period (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–16.13	–17.34	–14.06	9.13	10.55	10.93	9.32
Copper	–6.93	–27.93	–10.83	2.06	2.46	2.32	1.96
Steel	5.57	16.27	–15.32	7.21	5.25	1.03	0.76
Crude oil	28.58	–18.33	–5.19	10.24	5.74	2.16	1.30
EGW wages	1.69	0.84	3.27	3.60	2.40	1.70	0.60
General wages	0.90	–1.60	0.70	1.30	0.40	0.10	–0.60
Construction costs	2.75	–1.28	–1.64	1.00	0.65	–0.37	–2.22

Application of escalators to the capex program

AER draft decision

The AER considered that using the same set of weightings for each year of TransGrid's capex program was likely to distort its cost estimates. The AER therefore requested TransGrid remodel the impact of using annual weightings based on the capex allowance

122 Econtech, *Updated labour cost growth forecasts*, p. 21.
123 Econtech, Labour Cost Growth Forecasts 2007/08 to 2016/17.
124 TransGrid, response to information request, 8 April 2009.

determined in the draft decision. This resulted in an adjustment of $4.7 million ($2007–08).

Revised revenue proposal

TransGrid did not accept the AER's reduced allowance for the application of annual weightings to reflect the year to year variability of its capex program. It submitted that the $4.7 million removed from its capex should be reinstated.[125]

TransGrid considered its approach was robust and the 1.5 per cent difference that was found when its medium spending profile was subject to annual, rather than five yearly, weightings demonstrated the realistic nature of its approach. It noted further adjustment to its capex program was not required.[126]

Consultant review

PB noted that:[127]

- given the size of TransGrid's capex program, and the significant value of the escalation component, that more detailed analysis of cost escalation sensitivities was warranted
- notwithstanding the complexities of TransGrid's capital accumulation model, TransGrid could apply separate escalators on an annual basis to different expenditure categories
- TransGrid has used its ability to apply separate escalators on an annual basis for the purpose of land escalation.

PB also noted that the escalation component included in TransGrid's forecast capex allowance should be appropriately tested for sensitivities to annual expenditure profiles to maintain transparency and to reduce the variance in the calculation of the base escalation to which a further risk adjustment is subsequently applied.[128] It stated that given the complexities associated with TransGrid's capital accumulation model this analysis may be more efficiently undertaken outside the standard process.[129]

PB agreed that the 1.5 per cent difference that it calculated could appear small, due to the scale of the escalation allowance proposed by TransGrid, but that the $4.7 million difference was not immaterial.[130]

AER considerations

The AER has reviewed TransGrid's revised revenue proposal and PB's analysis and is not satisfied that TransGrid's proposed application of the same set of weightings for each year of its capex program reflects the costs a prudent operator in the circumstances of TransGrid would require to achieve the capex obejectives.

The AER considers that TransGrid's approach is not transparent and is likely to distort its cost estimates. The AER maintains that since the type of projects undertaken in each year

125 TransGrid, *Revised revenue proposal*, pp. 38–39.
126 TransGrid, *Revised revenue proposal*, pp. 38–39.
127 PB, pp. 43–44.
128 PB, pp. 43–44.
129 PB, p. 44.
130 PB, pp. 43–44.

vary, so to will the particular proportions of various inputs used in TransGrid's capex program. Accordingly, the weighting of escalation factors should reflect the year to year variability of TransGrid's capex program as this more reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, in accordance with the capex criteria.

The AER requested TransGrid to remodel the impact of using annual weightings based on the capex allowance determined in this final decision. This has resulted in an adjustment of $5.3 million ($2007–08).

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the revised revenue proposal, the AER is not satisfied that TransGrid's application of cost escalators in its revised revenue proposal reasonably reflects the capex criteria, including the capex objectives. In coming to view the AER has had regard to the capex factors. Following a request from the AER, TransGrid advised that the application of the updated real cost escalators and adjustments for the annual weightings in the capital accumulation model result in a reduction of $62 million ($2007–08) to its forecast capex allowance.[131]

3.6.10 Cost estimation risk factor

AER draft decision

In the draft decision, the AER accepted the modelling approach applied by Evans & Peck (EP) but considered the process of 'risk workshops' used to arrive at the risk adjustment factors did not lend itself to transparent assessment and had produced bias in expenditure adjustments. Specifically, the AER considered there was a lack of transparency in the factors considered at the workshops that suggested there was scope for the risk adjustment to reflect costs that were captured in other cost factors, including labour and materials escalators. Therefore, on balance, the AER considered the proposed risk adjustment was not appropriate.[132]

However, recognising the reasonableness of providing a risk adjustment for risks outside TransGrid's control, the AER considered that a risk adjustment allowance $11 million ($2007–08) less than that being sought was reflective of the costs that a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives in accordance with the capex criteria.[133]

Revised revenue proposal

TransGrid engaged EP to review and comment on the issues raised by the AER in the draft decision. Based on EP's comments, it did not accept the $11 million reduction associated with a perceived bias in its risk adjustment. It stated that an allowance of $72 million was reasonable for developing its capex allowance.[134]

TransGrid noted that:[135]

131 TransGrid, *Response to issue number 341*, 16 April 2009.
132 AER, *Draft decision*, p. 75.
133 AER, *Draft decision*, p. 75.
134 TransGrid, *Revised revenue proposal*, p. 42.
135 TransGrid, *Revised revenue proposal*, pp. 40–41.

> Evans & Peck had stated that the risk workshop approach is the best alternative when data from detailed analysis of past projects is unavailable. … [and] in the absence of this data, the outcome of the risk workshop provides the best estimates of a reasonable risk allowance.

TransGrid also stated that while an adjustment for the use of the median (P50) risk profile was reasonable, the draft decision was flawed. It suggested the AER had erred in the application of its risk adjustment and that, assuming a reduction was warranted, this had resulted in an amendment greater than that which was required.[136]

Submissions

Powerlink considered the risk adjustment proposed by TransGrid was reasonable. It highlighted that in its last regulatory control period its actual project costs were 9.4 per cent higher that its estimated costs.[137]

Consultant review

PB acknowledged that in the absence of detailed historical data, a risk workshop provided a reasonable means to develop a risk adjustment. However, it considered that TransGrid had neither demonstrated transparency in its workshop nor clearly defined the required objectives. It considered this resulted in an outcome that was not transparent, since costs captured through the risk workshop potentially included costs captured through other means.[138]

PB also considered that TransGrid had not demonstrated that a clear distinction between cost, escalation and quantity variance had been established in the workshop process. It noted that this would result in the inclusion of factors other than quantity variation in the risk workshop estimates.[139]

PB also noted a number of other concerns with TransGrid's risk escalation process, including its complexity and the lack of evidence that demonstrated that the risk workshop ensured that changes in escalation expectations had been considered and excluded from the process. As a consequence, it suggested that there was scope for the result to double count the impact of certain escalations on the risk portion of the project costs.[140]

PB recommended that an adjustment to remove the inclusion of the escalation from the risk allowance be made. It recommended that the total risk allowance of $72 million be reduced by $6.5 million—that is, reduced to $65 million—to remove this double counting.[141]

AER considerations

The AER has reviewed TransGrid's revised revenue proposal and the analysis provided by PB and considers that the process of risk workshops does not lend itself to transparent assessment and that this has resulted in a bias in expenditure adjustments.

136 TransGrid, *Revised revenue proposal*, p. 40.
137 Powerlink, 16 February 2009, p. 1.
138 PB, pp. 47–52.
139 PB, pp. 47–52.
140 PB, pp. 47–52.
141 PB, p. 52.

The AER notes Powerlink's view that the methodology applied and risk adjustment proposed by TransGrid was reasonable. The AER notes, however, that:

- in previous decisions it has generally accepted the modelling approach applied by EP[142]
- the use of historic data to inform a reasonable adjustment for risk in overall terms, is its preferred approach but recognises that there are data concerns
- the process of risk workshops does not lend itself to transparent assessment and great care must be taken when using this approach.

The AER shares PB's concern that TransGrid has failed to ensure that its proposed risk adjustment did not include costs that were captured elsewhere. That is, the AER considers there is a lack of transparency in the factors considered at the workshops that suggests there is scope for the proposed risk adjustment to reflect costs that are captured in other cost factors.

For the reasons discussed above and as a result of the AER's analysis of TransGrid's revised revenue proposal, the AER is not satisfied that the cost estimation risk factors included in TransGrid's capex proposal reasonably reflect the capex criteria, including the capex objectives. The estimate the AER is satisfied reasonably reflects the capex criteria is $6.5 million ($2007–08) less than that which TransGrid proposed. In coming to this view, the AER has had regard to the capex factors.

3.6.11 Contingent projects

AER draft decision

After reviewing TransGrid's proposed contingent projects ($2.3 billion), the AER approved nine projects with a total indicative cost of $1.2 billion.[143]

At a broad level, the AER found that the proposed contingent projects not accepted as contingent project had trigger events that were not sufficiently or specifically defined.[144] As such, the AER determined that they did not meet the requirements for a contingent project as detailed in the NER.[145]

Revised revenue proposal

TransGrid's revised revenue proposal revisited the contingent projects not accepted by the AER in the draft decision and included further information to address the AER's

142 AER, *Decision Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007; AER, *Draft decision SP AusNet transmission determination 2008–09 to 2013–14*, 31 August 2007; and AER, *Final decision ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008.
143 AER, *Draft decision*, pp. 81–82.
144 AER, *Draft decision*, p. 78.
145 AER, *Draft decision*, pp. 81–82.

concerns.[146] TransGrid also outlined that it withdrew two contingent projects and moved one contingent project to its ex ante capex.[147]

TransGrid also provided clarification on four contingent project triggers accepted by the AER in the draft decision.[148]

TransGrid sought approval for six projects not accepted in the draft decision. The total number of contingent projects that TransGrid sought approval for has therefore increased to 15, with an indicative cost of approximately $2 billion. Table 3.5 details the six revised projects that TransGrid sought approval for in its revised revenue proposal.

Table 3.5: Proposed contingent projects in TransGrid's revised revenue proposal ($m, 2007–08)

Project	Cost
CBD and inner metropolitan area supply	500
Gadara/Tumut load area support	54
Orange 330/132 kV substation	47
Victorian interconnector development	35
QNI upgrade—line series compensation project	60
Reactive support at seven sites	36

Source: TransGrid, *Revised revised revenue proposal*, appendix J, pp. 54–59.

Submissions

EnergyAustralia did not agree with the draft decision not to accept TransGrid's CBD and inner metropolitan area supply contingent project. It noted this project was the outcome of joint planning between TransGrid and itself and that the option proposed was the least cost option for augmenting the network. It also noted that if this project was not considered a contingent project, TransGrid would be unable to recover its efficient capital costs.[149]

In addition, EnergyAustralia noted that its forecast capex assumed the retirement of the 132 kV cables in the 2009–14 period and that it did not include any forecast replacement expenditure for those cables.[150]

The EUAA recommended that:[151]

- the AER should request detailed cost benefit analysis assessment for each of TransGrid's proposed contingent projects

146 TransGrid, *Revised revenue proposal*, p. 43.

147 Projects withdrawn from TransGrid's revised revenue proposal include its voltage compensation and system protection scheme. Further, the Williamsdale 330/132 kV substation project was moved to the ex ante allowance. Source: TransGrid, *Revised revenue proposal*, p. 45.

148 TransGrid, *Revised revenue proposal*, pp. 44–45.

149 EnergyAustralia, *EnergyAustralia's submission on AER's draft decision for other network service providers*, 16 February 2009, p. 6.

150 EnergyAustralia, S*ubmission on other network service providers,* p. 6 and EnergyAustralia, *Further submission*, February 2009, pp. 14–15.

151 EUAA, p. 13.

- TransGrid be required to show how its database of demand management opportunities was used in the evaluation of each contingent project.

TransGrid noted the role of triggers for contingent projects and that all contingent projects that are triggered are subject to review by the AER before it can be used as the basis for revenue cap adjustments.[152]

The AER also received confidential submissions in support of TransGrid's proposed:[153]

- Gadara/Tumut contingent project from Visy Pulp and Paper
- Orange 330/132 kV substation contingent project from Newcrest Mining Ltd.

Consultant review

PB reviewed the contingent projects listed in TransGrid's revised revenue proposal and identified that the capex threshold level required to be exceeded by a contingent project increased from $33.4 million to $35 million.[154] It also determined that four of the six revised projects satisfied the conditions required for a contingent project.

Table 3.6 summarises the revised contingent projects PB considered satisfied the conditions required for a contingent project.

Table 3.6: Proposed contingent projects PB recommended for inclusion ($m, 2007–08)

Project	Cost
CBD and inner metropolitan area supply	342
Gadara/Tumut load area support	54
Orange 330/132 kV substation	47
Reactive support at seven sites	36

Source: PB, p. 68.

Table 3.7 details the revised contingent projects not recommended by PB to be included as contingent projects.

Table 3.7: Proposed contingent projects not recommend for inclusion ($m, 2007–08)

Project	Cost
QNI upgrade—line series compensation project	60
Victorian interconnector development	35

Source: PB, p. 68.

PB also reviewed information provided in TransGrid's revised revenue proposal regarding the clarification of four of the contingent project triggers accepted in the draft

152 TransGrid, *Response to the submission by the EUAA*, p. 3.
153 Due to the confidentiality associated with these submissions, contents have not been disclosed.
154 NER, clause 6A.8.1(b)(2)(iii).

decision. It found the proposed amendments to TransGrid's triggers were reasonable. Table 3.8 details the accepted contingent projects amended by TransGrid.

Table 3.8: Accepted contingent projects that TransGrid sought to amend ($m, 2007–08)

Project	Cost
Hunter Valley–Central Coast 500 kV line	300
Yass to Wagga 500 kV	329
Richmond Vale 500/330 kV substation	80
Bannaby–Yass reinforcement	45

Source: PB, p. 68.

Further information on the drivers, scope and triggers for the contingent projects discussed in TransGrid's revised revenue proposal is detailed in appendix B of this final decision.

AER considerations

CBD and inner metropolitan area supply

The AER notes that TransGrid's revised revenue proposal outlines a refined project scope and clarifies the timing, need and costs associated with the advancement of the replacement of more than two the distribution network cables. Specifically, the AER notes that TransGrid revised downward its capital cost estimate from $650 million to $500 million in light of more detailed scoping on the components which was available. The estimated cost of the project is above the capex threshold level ($35 million)[155] required for a contingent project.

The triggers for this project are the receipt by TransGrid of a written notification from EnergyAustralia that states:

1. it is proposing to retire more than two of the four 132 kV cables (cables 929 or 919/3, 92L/3, 92M/3 and 928/3), two or more years before the predicted November 2017 commissioning date of the next 330 kV cable to be constructed to the Sydney CBD by TransGrid
2. as a consequence, EnergyAustralia will be unable to meet its reliability of supply obligation to the Sydney CBD.

As this project relates to an advancement of the installation of the Potts Hill to Surry Hills cable that would otherwise be installed around November 2017, the AER accepts that this will bring forward some of the pre–commissioning construction expenditure into the next regulatory control period.

155 This figure represents 5 per cent of TransGrid's maximum allowable revenue in the first year of the next regulatory control period (and is greater than $10 million). See clause 6A.8.1(b)(2)(iii) of the NER.

The AER is satisfied that this project has not otherwise been provided for (either in part or in whole), in the forecast capex and that it is reasonably required to achieve the capex objectives.

The AER accepts PB's findings that the revised project scope is reasonable but that a downward revision to the indicative cost of this project—to $342 million—is appropriate, as this represents the lowest overall NPV costing provided by TransGrid.[156]

Based on the information detailed above, TransGrid's revised documentation and PB's analysis, the AER is satisfied that TransGrid's revised revenue proposal reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors. The AER therefore considers that the CBD supply project now meets the requirements for a contingent project as detailed in clause 6A.8.1 of the NER.

Gadara/Tumut load area support

The AER notes that in its revised revenue proposal, TransGrid quantified its trigger event to include a step–change increase in electricity demand of more than 20 MW of industrial load, rather than a general reference to load growth.

The AER accepts PB's finding that TransGrid's Gadara/Tumut load area support contingent project scope and indicative costs are reasonable.[157] The AER notes that the proposed cost of this project is above the capex threshold level required for a contingent project.

The AER is satisfied that the proposed capital works may be required due to an expansion of an industrial plant in the Tumut/Gadara area that will require additional power transfer (more than 20 MW). The AER also notes that without this project the expansion of an industrial plant may overload the current 132 kV supply network and breach the reliability of supply obligations.[158]

The AER is also satisfied that this project has not otherwise been provided for (either in part or in whole), in the forecast capex and that it is reasonably required to achieve the capex objectives.

Based on the information detailed above, TransGrid's revised documentation and PB's analysis, the AER is satisfied that TransGrid's proposal reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors. The AER therefore considers that the Gadara/Tumut load area support project meets the requirements for a contingent project as detailed in clause 6A.8.1 of the NER.

Orange 330/132 kV substation

The AER notes TransGrid proposed an updated scope to more closely reflect the work required to meet network requirements. The AER further notes that the revised trigger includes an agreed increase in maximum demand and the acceptance of an offer to connect for the spot load increase.

---

156 PB's recommendation was based on its review of PES 6276. Source: PB, pp. 53–55.

157 PB, p. 55.

158 TransGrid, *Revised revenue proposal*, appendix J, p. 13.

The AER accepts PB's finding that the Orange 330/132 kV substation contingent project scope and indicative costs are reasonable. The AER notes that the proposed cost of this project is above the capex threshold level required for a contingent project. The AER is also satisfied that the proposed capital works may be required due to the expansion of the Cadia gold mine.[159]

The AER considers that this project has not otherwise been provided for (either in part or in whole), in the forecast capex and that it is reasonably required to achieve the capex objectives.

Based on the information detailed above, TransGrid's revised documentation and PB's analysis, the AER is satisfied that TransGrid's proposal reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors. The AER therefore considers that the Orange 330/132 kV substation project meets the requirements for a contingent project as detailed in clause 6A.8.1 of the NER.

Reactive support at six sites

The AER notes TransGrid proposed an updated scope and trigger for this project that is specific and verifiable. The proposed trigger clearly states a specific volume of reactive shunt power as well as a threshold cost for the procurement of reactive support from generators.

The AER notes that the concerns raised in the draft decision regarding this project being a combination of several smaller projects, which individually did not meet the materiality requirements for a contingent project, have been addressed. The AER considers that the maximum likely scope for this project exceeds the capex threshold level required for a contingent project.

The AER also considers that this project has not otherwise been provided for (either in part or in whole), in the forecast capex and that it is reasonably required to achieve the capex objectives.

The AER is also satisfied this project reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors. The AER therefore considers that the reactive support at six sites project meets the requirements for a contingent project as detailed in clause 6A.8.1 of the NER.

Queensland NSW interconnector upgrade—line series compensation project

The AER notes the indicative cost of this project is $120 million, of which $60 million will be incurred by TransGrid—the remainder will be managed by Powerlink.[160] This project is above the capex threshold level required for a contingent project.

The AER also notes that TransGrid revised the first of its two alternative triggers following discussions with the AER and PB. The AER considers that the first of these revised triggers, which specifies an increment (150–200 MW) above current capacity, meets the requirements for a contingent project as detailed in clause 6A.8.1 of the NER.

159 PB, pp. 56–57.

160 TransGrid, *Revised revenue proposal*, Appendix J, p. 38; and TransGrid, *Response to information request number 333*, 16 March 2009.

In terms of the alternative trigger, the AER notes that PB did not consider that passing the regulatory test was appropriate. The AER notes that it agrees with this approach and in the draft decision it did not support any project that proposed the regulatory test as its sole trigger. PB also considered that the proposed market benefits linked with this project (increased reliability and security), did not meet the capex objectives.

The AER engaged in further discussions with TransGrid to address the concerns associated with its alternative trigger and is now satisfied that this project meets the requirements for a contingent project as detailed in clause 6A.8.1 of the NER. This project can now be triggered (by its alternative trigger), if TransGrid identifies that there is a need to exceed the current capacity of the QNI by more than 150–200 MW and through the successful completion of the regulatory test demonstrating that this project will deliver net market benefits.

The AER considers that this project has not otherwise been provided for (either in part or in whole), in the forecast capex and that it is reasonably required to achieve the capex objectives.

Based on the amendments that have been undertaken, the AER is now satisfied that this project reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

Victorian interconnector development

The AER notes TransGrid revised the scope, capital cost and triggers for this project. It also notes that PB considered that the amendments resulted in only the first of two proposed triggers meeting the requirements for a contingent project as detailed in the NER. The AER notes that the proposed cost of this project is above the capex threshold level required for a contingent project

The AER further notes that this project, like the QNI contingent project, had the passing of the regulation test as its alternative trigger. For the same reasons detailed for the QNI project, the AER does not consider this is reasonable. The AER also notes that while TransGrid sought to demonstrate that this project was required to improve reliability and security of supply, PB considered that the proposed market benefits linked with this project (increased reliability and security), did not meet the capex objectives.

Further discussion between the AER and TransGrid addressed the concerns associated with this contingent project trigger. Specifically, this project can now be triggered if there is a need to exceed current capacity by approximately 180 MW above the current capacity of 1900 MW and through the passing of the regulatory test demonstrating that this project would deliver net market benefits. The AER therefore considers that the Victorian interconnector development project now meets the requirements for a contingent project as detailed in clause 6A.8.1 of the NER.

The AER considers that this project has not otherwise been provided for (either in part or in whole), in the forecast capex and that it is reasonably required to achieve the capex objectives.

Based on the amendments that have been undertaken, the AER is now satisfied that this project reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

Approved contingent projects clarified in TransGrid's revised revenue proposal

The AER accepts PB's findings that four of the contingent projects approved in the draft decision and amended to clarify the triggers in TransGrid's revised revenue proposal are reasonable.

The AER considers that these projects reasonably reflect the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors. The AER therefore considers that these projects still meet the requirements for a contingent project as detailed in clause 6A.8.1 of the NER.

AER conclusion

The AER accepts the six proposed contingent projects as proposed in TransGrid's revised revenue proposal. The indicative costs and triggers for these projects satisfy the requirements of the NER. The AER also accepts the amendments to the four contingent projects, to clarify the trigger events, as set out in TransGrid's revised revenue proposal.

The AER has therefore approved 15 contingent projects for TransGrid with a total indicative cost of approximately $1.8 billion. Appendix B provides a summary of all contingent projects approved by the AER and describes the triggers and indicative costs.

Table 3.9 sets out the AER's approved contingent projects and indicative costs.

Table 3.9: AER approved contingent projects and indicative costs ($m, $2007–08)

Project	Cost
Kemps Creek−Liverpool 330 kV line—undergrounding of all or part of the proposed connection	108
Hunter Valley–Central Coast 500 kV line	300
Darlington−Balranald system upgrade 275 kV	51
Yass to Wagga 500 kV double circuit transmission line	329
Liddell−Tamworth 330 kV	163
Tamworth−Armidale 330 kV line	130
Bannaby−Yass reinforcement	45
Williamsdale–Cooma 3rd circuit	40
New 500/330 kV substation at Richmond Vale	80
CBD and inner metropolitan area supply	342
Gadara/Tumut load area support	54
Orange 330/132 kV substation	47
Victorian interconnector development	35
QNI upgrade—line series compensation project	60
Reactive support at seven sites	36

3.7 AER conclusion

The AER has considered TransGrid's revised forecast capex proposal of $2.5 billion ($2007–08) and, for the reasons outlined in this chapter, is not satisfied that this total capex forecast proposed by TransGrid reasonably reflects the capex criteria under clause 6A.6.7(c) of the NER:

- the efficient costs of achieving the capex objectives
- the costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the capex objectives
- a realistic expectation of the cost inputs required to achieve the capex objectives.

In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6A.6.7(e) of the NER, including:

- the information included in or accompanying the revised revenue proposal
- submission received in the course of consulting on the revised revenue proposal
- analysis undertaken by or for the AER and is published as part of the final decision of the AER.

These are important considerations in determining whether the AER is satisfied that TransGrid's forecast capex proposal reasonably reflects the capex criteria, which are themselves couched in terms of achieving the capex objectives.

As the AER is not satisfied that TransGrid's forecast capex reasonably reflects the capex criteria, under clause 6A.6.7(d) of the NER, the AER must not accept the forecast capex in TransGrid's revised revenue proposal. Instead, the AER is required under clause 6A.14.1(2)(ii) of the NER to provide an estimate of the total capex that TransGrid will require over the next regulatory control period that the AER is satisfied reasonably reflects the capex criteria, taking into account the capex factors.

Based on its own analysis and the advice of PB, the AER has reduced TransGrid's revised capex proposal by $110 million. This represents a reduction of around 4.4 per cent to TransGrid's revised forecast capex.

The AER's amended capex allowance for the next regulatory control period is $2405 million and is set out in table 3.10 along with the adjustments made to TransGrid's revised forecast capex.[161] In addition, the AER has approved an indicative contingent projects allowance of $1.8 billion.

Although some adjustments made by the AER are set out on a project specific basis, it notes that the total capex after these adjustments is only an allowance. The AER's project specific conclusions should not be taken to bind TransGrid to a particular set of project specific capex budgets—TransGrid has discretion on how it allocates its capex allowance.

This amended allowance represents the AER's estimate of the total capex that a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives. The AER is satisfied that the amended capex allowance of $2405 million over the next regulatory control period, reasonably reflects the capex criteria, taking into account the capex factors.

161 The forecast capex allowance is $2464 million in 2008–09 dollar terms.

Table 3.10: AER conclusion on TransGrid's forecast capex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER capex allowance (draft decision)	523.2	436.5	538.2	506.7	372.4	2376.5
TransGrid revised revenue proposal	530.2	460.1	585.3	536.0	403.9	2515.5
Adjustments resulting from detailed project review	–1.9	–6.3	–7.0	–8.0	–13.4	–36.6
Adjustment to cost accumulation process[a]	–2.7	–4.6	–25.6	–20.3	–9.7	–62.2
Adjustment to cost estimation risk factor	–1.3	–1.2	–1.7	–1.4	–1.1	–6.5
Adjustment to cost estimating factors	–1.0	–0.9	–1.3	–1.0	–0.8	–5.1
Total adjustments	–6.9	–13.0	–35.6	–30.7	–24.2	–110.4
AER total capex allowance	523.3	447.1	549.7	505.2	379.7	2405.1

Note: Totals may not add up due to rounding.
(a) This includes adjustments to labour and materials cost escalators.

4 Cost of capital

4.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on TransGrid's weighted average cost of capital (WACC), including the averaging period of the risk–free rate, debt risk premium and inflation forecast raised by TransGrid in its revised revenue proposal.

The AER's consideration of debt and equity raising costs, and corporate tax allowances is not set out in this chapter because they are not compensated for through the WACC. The analysis of debt and equity raising costs is set out in chapter 5 and the analysis of corporate tax is outlined in chapter 9 of this decision.

4.2 AER draft decision

In the draft decision, the AER determined a nominal vanilla WACC of 9.82 per cent for TransGrid. The WACC was greater than that proposed by TransGrid, as TransGrid proposed the use of the historical average of the cost of debt to calculate the WACC. The WACC determined by the AER reflected increased corporate debt costs associated with developments in international financial markets.

Table 4.1 sets out the WACC parameter values determined for the draft decision.

Table 4.1: AER draft decision on TransGrid's WACC parameters

Parameter	TransGrid's proposal	AER's conclusion
Risk–free rate (nominal)	5.70%	5.46%
Risk–free rate (real)	3.10%	2.84%
Expected inflation rate	2.52%	2.55%
Debt risk premium	1.75%	3.27%
Market risk premium	6.00%	6.00%
Gearing	60%	60%
Equity beta	1.00	1.00
Nominal pre–tax return on debt	7.45%	8.73%
Nominal post–tax return on equity	11.70%	11.46%
Nominal vanilla WACC	9.15%	9.82%

Source: AER, *Draft decision*, p. 97.

4.3 Revised revenue proposal

In its revised revenue proposal, TransGrid did not agree with the AER's decision on the averaging period for the risk–free rate and the debt risk premium. TransGrid proposed that the averaging period for the risk–free rate and the debt risk premium be revised to exclude the impacts of the global financial crisis. TransGrid rejected the use of only Bloomberg data to estimate the debt risk premium. It also proposed alternative methodologies for estimating the debt risk premium and for deriving expected inflation.

4.4 Submissions

The AER received submissions from TransGrid and EnergyAustralia relating to TransGrid's cost of capital. TransGrid's submission included reports commissioned from Strategic Finance Group (SFG) and Professor Bruce Grundy.

4.5 Issues and AER considerations

4.5.1 Risk–free rate

Averaging period

TransGrid initially proposed an averaging period for the nominal risk–free rate of 20 business days commencing 30 days following lodgement of TransGrid's revenue proposal. In July 2008, the AER determined that this averaging period was unreasonable and informed TransGrid of the AER's decision.[162]

The AER rejected TransGrid's proposed averaging period on the basis that it was too far removed from the date when the AER would publish the final decision. The AER also noted that such an averaging period would be inconsistent with previous regulatory practice by the AER, ACCC and jurisdictional regulators, which set the averaging period for the risk–free rate at a date close to the final decision date. The AER advised that this regulatory practice was supported by finance literature and cited papers by Associate Professor Martin Lally and Professor Kevin Davis.[163]

In July 2008, the AER advised TransGrid that the risk–free rate would be based on a 20 business day averaging period commencing 23 February 2009 and ending 20 March 2009. The AER invited TransGrid to nominate an averaging period between 1 February 2009 and 20 March 2009 if it disagreed with the AER's proposed averaging period. In response, TransGrid nominated an averaging period of 20 business days commencing 2 February 2009 and ending 27 February 2009, which the AER accepted (agreed averaging period).[164]

162 AER, Letter to TransGrid: TransGrid's proposed nominal risk–free rate averaging period for the 2009–2014 regulatory control period, July 2008.

163 Martin Lally, *The cost of capital for regulated entities, report prepared for the Queensland Competition Authority*, 26 February 2004, p. 63; Martin Lally, *Determining the risk free rate for regulated companies, report prepared for the ACCC*, August 2002, p. 17; and Kevin Davis, *Report on risk free interest rate and equity and debt beta determination in the WACC, report prepared for the ACCC*, 28 August 2003, p. 16.

164 AER, Letter to TransGrid: Nominal risk–free rate averaging period for the 2009–14 regulatory control period, 22 September 2008.

AER draft decision

In the draft decision, the AER determined a nominal risk–free rate of 5.46 per cent based on a 20 business day moving average of yields on Commonwealth Government Securities (CGS) with a 10 year maturity for the period ending 17 October 2008. The AER noted that the risk–free rate would be updated, based on the agreed averaging period, at the time of the final decision. The averaging period accepted by the AER was not disclosed due to a request from TransGrid to keep the period confidential.

Revised revenue proposal

TransGrid did not agree with the AER's averaging period decision and commissioned the Competition Economics Group (CEG) to provide a report on the selection of an averaging period for the risk–free rate. The CEG report was provided as an attachment to TransGrid's revised revenue proposal.[165]

The CEG report recommended that the AER set an averaging period for the risk–free rate prior to September 2008 because the global financial crisis became worse at that time, best characterised by events such as Fannie Mae and Freddie MAC in the US being placed in conservatorship on 7 September 2008.[166]

CEG stated that the global financial crisis has resulted in downward biased yields on 10–year nominal CGS and noted that:

- The global financial crisis has increased volatility across the Australian equity market and caused a flight to safety, which has decreased yields on nominal CGS and increased the cost of equity.[167]
- The spread between yields on 10–year CGS and 10–year state government bonds is at historically high levels due to a liquidity premium being paid for CGS.[168]
- There has been a sudden fall in the 10–year break even (market inferred) inflation rate,[169] which is either due to investors' increased demand for nominal CGS or alternatively lower inflation expectations.[170]

CEG stated that the NER requires an averaging period for the risk–free rate to be chosen such that it results in an adequate rate of return:[171]

> Other things being equal, the optimal averaging period is one that is most consistent with providing an accurate estimate of the cost of equity and debt for the regulated business. That is, a cost of equity and debt that, when inserted into

165 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009.
166 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 30–32.
167 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp.34–38.
168 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 38–40.
169 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 44.
170 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 45.
171 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 7.

> the WACC formula in the Rules provides a rate of return to the regulated business equivalent to that required by investors in a commercial enterprise with a similar nature and degree of non–diversifiable risk as that faced by the regulated business.

CEG stated that an averaging period subject to market conditions post September 2008 would result in an estimate of the cost of equity that results in a rate of return inconsistent with clause 6A.6.2(b) of the NER.[172]

CEG stated that the reports by Lally and Davis, which the AER cited in its July 2008 letter to TransGrid rejecting its proposed averaging period, do not support the AER's averaging period decision. CEG noted that these reports state:[173]

- an averaging period is used to minimise exposure to rates on an aberrant day
- a market risk premium based on historical data should not be accepted uncritically and the market risk premium can be expected to vary over time.

CEG stated that, when 'properly construed' the Lally and Davis reports support the use of an averaging period that avoids the current market conditions, which are aberrant and that the market risk premium is fixed based on historical data.[174]

CEG stated that previous regulatory decisions in Australia[175] as well as decisions in the UK and the US, have adjusted the averaging period for the risk–free rate to account for specific events. It stated that these decisions support the use of an averaging period that excludes the impacts of the global financial crisis.[176]

CEG stated that there is no basis to presume that the yield on BBB+ debt prevailing at the beginning of the regulatory control period is a superior proxy for a business' actual cost of debt than 12 months prior. CEG stated that this is particularly true because a regulated business is likely to re–finance or hedge its debt obligations over a longer period of time than one particular averaging period.[177] CEG stated that, given the increased discrepancies between the CBASpectrum and Bloomberg estimates of BBB+ rated corporate bond yields, an averaging period close to the final decision date could result in an inaccurate proxy for a regulated business' actual cost of debt.[178]

---

172 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 12.

173 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 13.

174 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 14.

175 ACCC, *Draft decision, Powerlink revenue cap decision 2002–2006/07; ESCV, Final decision Electricity distribution price review 2006–10.*

176 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 16.

177 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 19–25.

178 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 26.

Consistent with TransGrid's revenue proposal, CEG stated that there are valid reasons for a business to prefer to have certainty about the rate of return it can earn prior to deciding on a capital expenditure program.[179]

Based on the CEG report, TransGrid proposed a nominal risk–free rate of 5.86 per cent, using a 20 business day averaging period ending 5 September 2009.[180]

Submissions

TransGrid stated that the NER does not specify a date to be used for the risk–free rate averaging period because it could lead to unintended outcomes, such as downward biased CGS yields used as a proxy for the risk–free rate.[181]

TransGrid's submission referred to reports from SFG[182] and Professor Bruce Grundy[183] addressing the WACC and the averaging period.

The SFG and Grundy agreed with the analysis and conclusions of the January 2009 CEG report provided as an attachment to TransGrid's revised revenue proposal. SFG stated that due to the effects of the global financial crisis, the AER's proposed averaging period would result in a downward biased rate of return. SFG stated:

- Current yields on nominal CGS are the lowest they have been in 40 years and the decline corresponds with the onset of the global financial crisis.[184]
- The AER's proposed averaging period would result in a rate of return on equity only marginally higher than yields on investment grade debt. SFG stated that this is economically implausible, given debt holders' contractual rights to receive payments, which are greater than equity holders' residual rights over a company's assets.[185]
- Dividend yields and default spreads are currently at very high levels indicating required returns on both debt and equity are high.[186]
- Price earnings ratios are at their lowest levels since 1991 and the sharp decline in equity prices indicates that either expected cash flows to perpetuity have declined or investors' required rates of return have increased.[187]

SFG stated that capital asset pricing model (CAPM) theory does not suggest that an averaging period close to the final decision date will lead to the best estimate of the risk–free rate and that, in the current market conditions, an averaging period close to the final decision date is likely to result in an economically implausible estimate of the rate of return.

179 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 26–28.
180 TransGrid, *Revised revenue proposal*, p. 53.
181 TransGrid, *Submission of expert opinion supporting TransGrid's revised revenue proposal*, 16 February 2009, p. 2.
182 SFG, *Review of TransGrid approach to WACC averaging period*, 14 February 2009.
183 Grundy B., *The WACC and the averaging period*, 16 February 2009.
184 SFG, p. 21.
185 SFG, pp. 12–14.
186 SFG, pp. 14–15.
187 SFG, pp. 22–23.

Grundy stated that a 6 per cent market risk premium fixed under the NER is downward biased following 7 September 2008, due to the volatility caused by the global financial crisis. Grundy stated that this is supported by the increased volatility implied by index option prices in the Australian equity market.[188]

Grundy also stated that the downward bias in the rate of return caused by the fixed market risk premium will be compounded by an averaging period for the risk–free rate that is affected by the global financial crisis. Grundy stated that a paper by Luba, Sinha and Swaminathan concludes that during a flight to quality the market risk premium increases by more than the fall in yield on government securities.[189]

AER considerations

The AER's detailed considerations of TransGrid's revised averaging period are presented in appendix C of this final decision. The AER notes that the consultancy reports submitted by TransGrid on this matter are also applicable to the AER's considerations concerning Transend's revised revenue proposal and the revised regulatory proposals of ActewAGL and the NSW DNSPs. The AER considers that its approach should be consistently applied across each of these businesses. Accordingly, appendix C sets out the AER considerations of all material submitted as part of the current regulatory processes and is applicable to the AER's final decisions for TransGrid, Transend, ActewAGL and the NSW DNSPs.

In summary, the AER considers that its decision to withhold agreement to the averaging period in TransGrid's revenue proposal was reasonable and that the agreed averaging period is consistent with finance theory, regulatory practice, the NER and NEL.

The AER considers the use of an averaging period as close to the start of the next regulatory control period as practically possible is consistent with the forward looking nature of the CAPM and is correct in finance theory. The AER notes that given the evidence at the time, the additional material contained in the revised revenue proposal does not justify a conclusion that the AER's decision to withhold agreement to the proposed averaging period, and consequently the agreed averaging period, was inconsistent with regulatory practice.

The AER notes that the arguments put forward by TransGrid regarding an insufficient return on equity is based on the view that the market risk premium (MRP) of 6 per cent in the NER (based on a historical average) is out of line with the current variations in the MRP. In essence, TransGrid is arguing for a variable MRP to be applied in the CAPM. However, given that the MRP is prescribed in the NER, TransGrid appeared to suggest that it is reasonable to account for variations in the MRP via adjustments to the risk–free rate. The AER notes that adjusting the risk–free rate averaging period as a mechanism to achieve the outcome equivalent to adopting a higher MRP (due to implied or actual variations to the historical MRP) would circumvent WACC parameters prescribed (subject to 5 yearly reviews) in the NER and would undermine the intended certainty under the regulatory regime which results from these values being prescribed.

The fact that CGS yields are at (or close to historical lows) does not of itself mean they cannot be used. Interest rates move all the time and reflect the market's assessment of the

[188] Grundy B., pp. 13–16.
[189] Grundy B., pp. 13–16.

price of money at the time. Expectations about the prospect for prices and growth will influence this assessment. If TransGrid can lock in an averaging period that it considers achieves the most advantageous rate of return early in the regulatory process based on its view on future interest rate movements then it may create opportunities for ‘gaming’ the regulator if its view transpires to be disadvantageous. In June 2008 when the AER received TransGrid’s revenue proposal the interest rate yield curve was downward sloping. The downward sloping yield curve at that time reflects market expectations of lower interest rates in the future. Therefore, setting the risk–free rate based on an averaging period at that time would have lead to systematic ex ante overcompensation by firms relative to the efficient cost of capital and would be inconsistent with the forward looking nature of CAPM—that is, it would not result in an unbiased risk–free rate.

The AER considers that the material provided by TransGrid in support of its revised revenue proposal does not reasonably justify that an averaging period prior to September 2008 is better than a period that is as close as practically possible to the start of the next regulatory control period. Moreover, the agreed averaging period does not exclude the downward movement of the CGS yields commensurate with an easing in monetary policy and a softening in economic growth. The AER considers that the agreed averaging periods are not abnormal and setting the risk–free rate using this period is also consistent with the NEL objective of efficient investment. The AER therefore considers that the agreed averaging period does not represent an abnormal period in relation to the observed CGS yields.

The nominal risk–free rate averaging period that the AER has adopted for this final decision is 20 business days commencing 2 February 2009 and ending 27 February 2009. The 20 business day moving average for CGS yields[190] with a 10–year maturity for the period ending 27 February 2009, results in a proxy nominal risk–free rate of 4.29 per cent (effective annual compounding rate). The AER is satisfied that this proxy nominal risk–free rate has been determined in accordance with clauses 6A.6.2(c) and (d) of the NER.

4.5.2 Debt risk premium

AER draft decision

In the draft decision, the AER determined a benchmark debt risk premium of 3.27 per cent, which was added to the nominal risk–free rate to determine the return on debt for the WACC calculation.[191] The debt risk premium was calculated using Bloomberg estimates of fair yields on long term corporate bonds, based on an averaging period of 20 business days ending 17 October 2008–consistent with the averaging period for the risk–free rate.[192]

The AER used Bloomberg estimates rather than CBASpectrum estimates for the fair yields of 10–year BBB+ rated corporate bonds based on the results of a review conducted during previous revenue determinations.[193] The review concluded that Bloomberg provided better estimates of 10–year BBB+ fair yields than CBASpectrum because they were more consistent with the observed yields of similarly rated actual bonds. The AER

190 RBA, CGS yields at: http://www.rba.gov.au/Statistics/indicative.html.
191 AER, *Draft decision*, p. 94.
192 AER, *Draft decision*, p. 94.
193 AER, *Draft decision*, pp. 93–94.

noted that the debt risk premium would be updated, based on the agreed averaging period, at the time of the final decision.

Revised revenue proposal

TransGrid did not agree with the AER's method for setting the debt risk premium and commissioned CEG to provide a report on the calculation of the debt risk premium. Based on the CEG report, TransGrid proposed that the debt risk premium be calculated using an averaging period prior to September 2008, consistent with TransGrid's proposed averaging period for the risk–free rate.

TransGrid did not agree with the AER's methodology and cited CEG's analysis that the current lack of liquidity in the market for existing BBB+ corporate bonds means that neither Bloomberg nor CBASpectrum data are likely to provide a reliable estimate of bond yields.[194] The CEG report suggested that rather than relying solely on Bloomberg or CBASpectrum estimates, the AER could take a simple average of estimates from Bloomberg and CBASpectrum data to provide a more reliable estimate.[195]

Based on a simple average of estimates from Bloomberg and CBASpectrum, and an averaging period of 20 business days ending on the 5 September 2008, TransGrid proposed a debt risk premium of 3.21 per cent.[196]

Submissions

SFG and Grundy agreed with CEG's report that there is currently illiquidity in the 10–year BBB+ Australian corporate bond market, which has affected the reliability of estimates of bond yields. SFG and Grundy stated that, in the current market conditions, neither CBASpectrum nor Bloomberg provide better estimates of the debt risk premium. SFG and Grundy stated that a simple average of CBASpectrum and Bloomberg estimates of long–term corporate bond yields would provide a more reliable estimate.[197]

AER considerations

The AER notes that in its revenue proposal TransGrid did not propose the use of CBASpectrum or Bloomberg fair yield estimates in the calculation of the debt risk premium. A significant divergence has developed over the past nine months between the corporate bond fair yields reported by Bloomberg[198] and CBASpectrum, as displayed in figure 4.1. Since January 2009, the Bloomberg BBB+ 10–year fair yield has remained relatively steady while the CBASpectrum fair yield has risen sharply. Consequently the difference in the two fair yields surpassed three percentage points on 19 March 2009.

194 TransGrid, *Revised revenue proposal*, pp. 54–56.

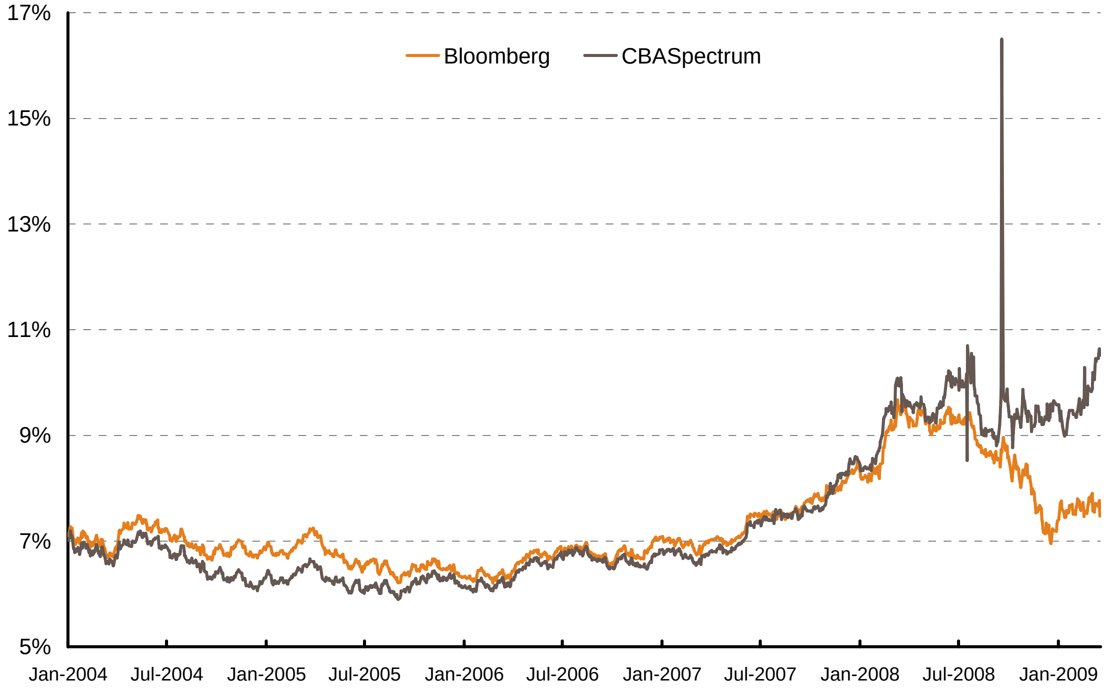
195 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 57.

196 TransGrid, *Revised revenue proposal*, p. 57.

197 SFG, pp. 24–26 and Grundy B., pp. 19–22.

198 Bloomberg's BBB fair yields are assumed to approximate BBB+ fair yields due to the estimation technique employed and the market being disproportionately weighted with longer term BBB+ rated bonds. Due to a lack of long term BBB+ or similar rated bonds, Bloomberg does not report a 10 year BBB+ fair yield. As set out in the draft decision, the AER has derived the BBB+ 10 fair year yield by adding the spread between the A rated 8 and 10 year fair yields to the BBB+ 8 year fair yield.

Figure 4.1: BBB+ 10–year fair yield estimates



Source: Bloomberg, CBASpectrum and AER analysis.

In previous revenue determinations the AER compared the estimated average daily fair yields for corporate bonds with a BBB+ credit rating from the Bloomberg and CBASpectrum databases.[199] The review indicated that Bloomberg provided estimates of BBB+ rated long–term fair yields that were more consistent with the observed yields of similarly rated actual bonds. However, given the current divergence between the two data sources the AER considers that the fair yields reported by the two sources should be reviewed again.

To undertake the analysis, the AER first identified the BBB+ rated bonds with a maturity of at least two years, which are listed in table 4.2. The AER then compared the observed yields of these bonds as quoted by both Bloomberg and CBASpectrum with the fair yields from the two sources.[200] The AER compared the actual observed bond yields with the fair yields from 2 February to 20 March, covering the averaging periods for the NSW DNSPs, ActewAGL, TransGrid and Transend. The average observed yields, and the average Bloomberg and CBASpectrum fair yields over the period analysed are outlined in table 4.2.

[199] AER, *Draft decision Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 8 December 2006, pp. 103–104 and AER, *Directlink Joint Venturers' application for conversion and revenue cap, Decision*, 3 March 2006, pp. 211, 221.

[200] For each bond, fair yields were calculated for each day by linear interpolation of the two fair yields that straddled the maturity of the bond.

Table 4.2: BBB+ rated bonds with a maturity of two years or greater (per cent)

Issuer	Maturity	Average observed yield		Average fair value	
		Bloomberg	CBASpectrum	Bloomberg	CBASpectrum
Origin Energy	6 October 2011	6.084	Not reported	6.202	7.698
Tabcorp	13 October 2011	6.295	6.446	6.213	7.710
Lane Cove Tunnel	9 December 2011	Not reported	9.755[a]	6.301	7.808
Coles Group	25 July 2012	6.647	6.412	6.699	8.162
Snowy Hydro	25 February 2013	6.891	7.797	7.082	8.473
Lane Cove Tunnel	9 December 2013	Not reported	11.135[a]	7.195	8.797
Santos	23 September 2015	7.384	8.053	7.396	9.327
Babcock & Brown Infrastructure Group	9 June 2016	7.487[b]	12.958	7.473	9.472
Adelaide Airport	20 September 2016	7.280[b]	Not reported	7.504	9.524

Source: Bloomberg, CBASpectrum and AER analysis

(a) The yields of the two Lane Cove Tunnel bonds did not change during the period indicating that the bonds were illiquid and no trades had occurred.

(b) The yield reported by Bloomberg was an estimation of the fair price of this bond when compared with bonds in the same sector not a traded price.

Three measures were used to test the differences between the actual reported yields and the fair yields reported by CBASpectrum and Bloomberg:[201]

- mean daily difference
- mean daily absolute difference
- mean daily squared difference.

In the analysis the Origin Energy bond was excluded because CBASpectrum did not report yields for this bond. The two Lane Cove Tunnel bonds were excluded because the bonds were illiquid and Bloomberg did not report yields for them. The Babcock and Brown Infrastructure Group and the Adelaide Airport bonds were excluded because the yields reported by Bloomberg were fair yield estimates not yields based on prices from observed trades. The results of this analysis are summarised in table 4.3.

201 The mean daily difference is the arithmetic mean of the difference between the observed yield of each bond and its corresponding estimated fair yield calculated daily. The mean daily absolute difference is the arithmetic mean of the absolute difference between the observed yield of each bond and its corresponding estimated fair yield calculated daily. The mean daily squared difference is the arithmetic mean of the difference between the observed yield of each bond and its corresponding estimated fair yield squared, calculated daily.

Table 4.3: Fair yield analysis results with Bloomberg observed yields

	Bloomberg	CBASpectrum	Average fair yield
Mean daily difference (per cent)	–0.023	1.526	0.751
Mean daily absolute difference (per cent)	0.138	1.526	0.751
Mean daily squared difference (per cent squared)	0.029	2.415	0.602

Source: Bloomberg, CBASpectrum and AER analysis.
Note: The average fair yield represents the average of the Bloomberg and CBASpectrum fair yields.

As outlined in table 4.3, the mean daily difference between the fair yield and the Bloomberg observed yield was much closer to zero for Bloomberg fair yields. Using Bloomberg fair yields also gave a significantly lower mean daily absolute difference and mean daily squared difference. For the CBASpectrum fair yields the mean daily difference equalled the mean daily absolute difference, which indicates that for every day included in the analysis, the CBASpectrum fair yield was higher than the observed yield reported by Bloomberg for every BBB+ bond with a maturity of at least two years. This analysis suggests that the CBASpectrum fair yields were biased upward in the period from 2 February 2009 to 20 March 2009.

Table 4.4: Fair yield analysis results with CBASpectrum observed yields

	Bloomberg	CBASpectrum	Average fair yield
Mean daily difference (per cent)	–0.329	1.241	0.456
Mean daily absolute difference (per cent)	0.618	1.275	0.659
Mean daily squared difference (per cent squared)	0.610	1.977	0.645

Source: Bloomberg, CBASpectrum and AER analysis.
Note: The average fair yield represents the average of the Bloomberg and CBASpectrum fair yields.

When the observed bond yields reported by CBASpectrum are used, the mean daily difference between the fair yield and the observed yield is again closest to zero for Bloomberg fair yields. In fact, Bloomberg fair yields again perform best for all three measures. Again, the results for CBASpectrum fair yields are the least favourable for all three measures. The results in table 4.4 also reflect the fact that the observed yields reported by CBASpectrum were mostly higher than the observed yields reported by Bloomberg.

The AER notes that during the period analysed Bloomberg did not report observed yields for all bonds for all trading days. Since late 2007, there have been significant periods of time for which observed yields have not been quoted for particular bonds due to illiquidity in the corporate bond market. The AER notes that it was during late 2007 that the Essential Services Commission of Victoria (ESCV) tested the fair yields of Bloomberg and CBASpectrum for its 2008 gas access arrangement review. As noted by CEG, the ESCV stated in its review that:[202]

[202] ESCV, *Gas access arrangement review 2008–2012: Final decision*, 7 March 2008, p. 487.

> …the analysis conducted in the estimation of the debt premium (below) shows that CBASpectrum has performed better in predicting bond yields than Bloomberg under current market conditions.

This was one of the conclusions of the Allen Consulting Group (ACG)[203] which undertook the analysis referred to by the ESCV. In its report, ACG stated that it considered that:[204]

> … the suggested error in fair yield predictions of Bloomberg of –2 to 4bp is not material and the absence of material over-prediction is consistent with there being no broader theoretical or empirical reasons to suggest that Bloomberg systematically errs in its predictions of fair-value yields.
>
> The suggested error in the CBASpectrum fair-yield predictions is greater than for Bloomberg and, importantly, suggests over-estimates of yields contrary to indications in mid 2007 of systematic negative bias in CBASpectrum fair yield predictions.

At first glance this quote appears inconsistent with the ESCV quote and suggests that the analysis conducted by ACG indicated Bloomberg, not CBASpectrum, performed better in predicting bond yields under the market conditions prevalent during the 20 days business days to 21 December 2007. In fact, the ACG analysis found that over the 20 business days to 21 December 2007 Bloomberg overestimated bond yields by 3.2 basis points on average while CBASpectrum overestimated yields by 17.6 basis points.[205]

However, ACG concluded that:[206]

> As the debt margins derived from Bloomberg relied on extrapolation of fair value yields for 7 and 8 year bonds rather than direct predictions, we suggest that greater weight may be given to the debt margins derived from CBASpectrum, and hence the higher values in these ranges.

Consequently, it appears that the basis for the conclusion that CBASpectrum performed better in predicting bond yields than Bloomberg under the market conditions at that time was because CBASpectrum provided a 10–year BBB+ fair yield estimate while Bloomberg only estimated fair yields for maturities up to eight years.

The AER therefore does not consider that the ACG analysis conducted for the ESCV indicated that CBASpectrum performed better at predicting BBB+ bonds yields than Bloomberg. Rather, the AER considers that the ACG analysis found that Bloomberg performed better than CBASpectrum at predicting BBB+ bond yields for bonds with a maturity up to eight years. Because the longest term to maturity of the bonds considered by ACG was eight years the analysis does not indicate whether Bloomberg or CBASpectrum performed better at predicting the fair yield of BBB+ bonds with a 10–year maturity.

In its final decision for SP AusNet, the AER tested both the CBASpectrum 10–year BBB+ fair yield and the extrapolated Bloomberg BBB eight year fair yield to test which was the best proxy for the Bloomberg BBB 10–year fair yield. The two fair yields were

203 ACG, *Memorandum: Gas access arrangement review 2008: updating estimates of debt margins for 20 trading days to November 2007 and December 2007*, 25 January 2007, p. 4.
204 ACG, *Memorandum*, p. 8.
205 ACG, *Memorandum*, p. 7.
206 ACG, *Memorandum*, p. 8.

tested over the 18 month period to October 2007 when Bloomberg ceased publishing a BBB 10–year fair yield. The analysis found that the eight year Bloomberg BBB fair yield plus the spread between the eight and 10–year Bloomberg A fair yields was the best proxy over the sample period.[207]

Consequently, the AER considers that the ACG analysis conducted for the ESCV, when considered alongside the analysis the AER undertook in its final decision for SP AusNet, indicates that Bloomberg, not CBASpectrum, performed better in predicting bond yields under the market conditions prevalent during the 20 business days to 21 December 2007.

In conjunction with the analysis that compared observed BBB+ bond yields with the fair yield estimates of Bloomberg and CBASpectrum, the AER has also reviewed the methodologies adopted by these data providers.

The AER notes that the methodologies adopted by Bloomberg and CBASpectrum to estimate fair yields are significantly different. The AER understands, based on work undertaken by NERA, that CBASpectrum fair yield estimates for bonds with a given credit rating are based on observed yields for bonds of all credit rating. Thus, the BBB+ 10–year fair yield will be a function of not only the observed yields of BBB+ bonds but also the yields of long dated bonds with other credit ratings. By contrast, Bloomberg's BBB fair yield curve estimates are based only on the observed yields of a sample of BBB–, BBB and BBB+ corporate bonds.[208]

The AER considers that the two methodologies have different strengths and weaknesses. Currently there is a shortage of long dated BBB bonds in the market. This, combined with the methodology it adopts, has resulted in Bloomberg discontinuing its 10–year BBB fair yield.

CBASpectrum, on the other hand, draws on observed yields for all bond ratings when calculating its fair yield for a given rating, thus enabling it to estimate a 10–year BBB+ fair yield estimate. However, in doing so it makes a number of assumptions such as the functional form of the yield curves and that yield curves of different ratings do not cross. Because of these assumptions, when tested against observed bond yields the Bloomberg fair yield estimates for similar rated bonds will usually be found more in alignment.

Another important consideration when comparing the fair yields of Bloomberg and CBASpectrum is the observed yields used by the two data providers to estimate the fair yield curves. This is particularly important in the current economic climate where the trading of a significant number of bonds is either thin or non–existent. Because bonds are typically traded 'over the counter' rather than on a centralised exchange it can be difficult to observe the market price. The AER understands that CBASpectrum's observed yields are based only on trades in which the Commonwealth Bank participates in. By contrast, Bloomberg's observed yields are based on trade information provided to it by a wide range of different financial institutions. Consequently, the AER considers that the observed bond yields reported by Bloomberg provide a better reflection of the true market price than those reported by CBASpectrum.

[207] AER, *Final decision SP AusNet 2008–09 to 2013–14*, pp. 95–98.
[208] NERA, *Critique of available estimates of the credit spread of corporate bonds*, May 2005.

In reviewing the CBASpectrum methodology, the AER noted that the credit ratings reported by CBASpectrum were sometimes outdated. For example, the Babcock and Brown Infrastructure bond was rated, as at March 2009, as A– in CBASpectrum despite it being re–rated as BBB+ by Standard and Poor's on 6 June 2008. The AER considers that in the current economic climate, where bonds are more likely to be re–rated downward than upward, any delay in updating credit ratings will result in an upward bias to the fair yield estimates of CBASpectrum.

To the extent that the observed bonds used to calculate the fair yields are quite different the AER considers that this is the most probable cause of the discrepancy in the fair yield estimates of CBASpectrum and Bloomberg. If the observed bonds used were all representative of the credit rating under consideration, then that alone would give rise to only minor sampling variations. However, the key problem is that the market perceived credit rating of all bonds is continually changing and a bond's credit rating may no longer reflect the market perceived credit rating. As a result of the global financial crisis many existing bonds are no longer regarded by markets as being of investment grade, and pricing and yields change to reflect this. In the current economic climate some bonds are reporting extremely high yields indicating that investors no longer consider those bonds to be of investment grade.

The AER considers that these bonds, which are no longer considered by the market as being of investment grade, should not be included in any sample of bonds used to estimate an efficient benchmark debt risk premium. The AER notes that Bloomberg publishes the bonds, and corresponding yields, that it uses each day to estimate its BBB fair yield curve. The AER reviewed the bonds used by Bloomberg to estimate its BBB fair yield curve during the averaging period (February to March 2009) and found no significant variability in the yields that might suggest inappropriate sample selection. Despite directly contacting CBASpectrum, the AER has been unable to confirm which bonds CBASpectrum uses to estimate its fair yields and if it removes any outliers.

The AER also notes that the CBASpectrum fair yields exhibit significantly more variability than the Bloomberg fair yields (see figure 5.1). For example, the CBASpectrum BBB+ 10–year yield had risen to 16.5 per cent on 19 September 2008 from 9.9 per cent the previous day. The next day it returned to 9.8 per cent. The cause of this volatility is unclear.

On 3 April 2009 the AER received a further submission from TransGrid that included a memorandum from CEG.[209] The memorandum noted that on 24 April 2009 Tabcorp announced a five year bond issue, to be rated BBB+, which CEG claimed provided evidence that CBASpectrum fair value estimates are more accurate than Bloomberg fair value estimates post September 2008.[210]

The AER notes that the prospectus for the proposed Tabcorp five year bond issue outlines the interest payable will be a variable interest rate. The variable interest rate will be set for each interest period equal to the 3–month bank bill rate[211] plus a 'margin' of 4.25 per cent.[212] As at 23 March 2009, the initial interest rate would be 7.28 per cent.[213] The AER

---

209 CEG, *Memorandum: Evidence from recent capital issues in Australia*, 3 April 2009.

210 CEG, *Memorandum: Evidence from recent capital issues in Australia*, p. 1.

211 Tabcorp, *Tabcorp bonds: prospectus for the issue of five year Tabcorp bonds to be listed on ASX*, 24 March 2009, p. 6.

212 Tabcorp, *Tabcorp bonds margin now set and offer now open*, 1 April 2009, p. 1.

notes that on 23 March 2009 the Bloomberg five year BBB fair yield was 7.41 per cent and the CBASpectrum five year BBB+ fair yield was 9.67 per cent. Further, the AER notes that the fair yields represent estimates for fixed interest bonds, not variable interest bonds. While there are ways of converting the yield of a variable rate bond to the yield of an equivalent fixed rate bond, the AER does not consider it appropriate to compare the yields on variable rate bonds with those of fixed rate bonds for the purpose of assessing the fair yield estimates from Bloomberg and CBASpectrum.

Given these considerations, the AER is of the view that Bloomberg fair yields are a better predictor of observed yields than an average of Bloomberg and CBASpectrum fair yields or CBASpectrum fair yields alone. Consequently, the AER does not consider it reasonable to use an average of the Bloomberg fair yield and the CBASpectrum fair yield to derive the Australian benchmark rate for corporate bonds with a maturity of 10 years and a credit rating of BBB+. The AER therefore maintains its draft decision to use Bloomberg fair yields for the purposes of determining the benchmark debt risk premium for the TransGrid.[214]

Consistent with previous regulatory practice, the AER considers that the debt risk premium should be determined with reference to the same averaging period that was adopted for determining the risk–free rate. TransGrid has proposed that the averaging period for the debt risk premium should be consistent with the risk–free rate. For this final decision, the 20 business day moving average benchmark debt risk premium for the period ending 27 February 2009, based on BBB+ rated corporate bonds with a maturity of 10 years, is 3.49 per cent (effective annual compounding rate). Adding this debt risk premium to the nominal risk–free rate of 4.29 per cent provides a nominal return on debt of 7.78 per cent. The AER is satisfied that the debt risk premium is consistent, under clause 6A.6.2(e) of the NER, with the required margin between the 10–year CGS yield and observed Australian benchmark corporate bond yields corresponding to BBB+ credit rating and maturity of 10 years.

4.5.3 Expected inflation

AER draft decision

The AER determined a 10–year inflation forecast of 2.55 per cent per annum. The inflation forecast was based on a simple average of the Reserve Bank of Australia's (RBA) forecasts of short term inflation—currently extending out to two years—and the mid–point of the RBA's target inflation band for the remaining years in the 10–year period.

The AER did not accept TransGrid's approach to forecasting inflation, which was based on advice from CEG. TransGrid's inflation forecast was calculated using a weighted average mean of professional economic forecasters' short–term inflation expectations and the mid–point of the RBA's long–term target inflation band, yielding an inflation rate of 2.52 per cent per annum.[215]

---

213 The Tabcorp bond prospectus (on page 1) states that the initial interest rate would be between 7.03 per cent and 7.53 per cent. Based on the confirmed margin of 4.25 per cent this equates to an initial interest rate of 7.28 per cent.

214 The fair yield as a proxy for the corporate bond yield less the CGS yield as a proxy for the risk-free rate produces the debt risk premium.

215 AER, *Draft decision,* p. 95.

The AER determined that, consistent with recent transmission determinations, an inflation forecasting methodology based on the RBA inflation forecasts and the mid–point of the RBA's target inflation band is objective and represents the best estimate of forecast inflation.[216] The AER noted that the inflation forecast would be updated using the latest forecasts at the time of its final decision.[217]

Revised revenue proposal

TransGrid stated that it would accept the use of the RBA's inflation forecasts, but only if the AER adopted TransGrid's revised revenue proposal averaging period for the nominal risk–free rate. Based on advice from CEG,[218] TransGrid stated that there is an inconsistency with the approach of simultaneously adopting an averaging period close to the final decision date and using an average of the RBA's short–term inflation forecasts and the mid–point of the RBA's target inflation band to estimating the inflation forecast. In particular, TransGrid noted that the real risk–free rate derived by taking the nominal CGS yield less the RBA inflation forecast would be below the indexed CGS yield.[219]

TransGrid noted that it had received advice from CEG that adjustments could be made to the methodology for estimating expected inflation if the AER adopted an averaging period for the risk–free rate close to the final decision date.[220]

CEG stated that continuing the draft decision methodology would result in two critical inconsistencies in current market conditions, which are:[221]

- providing a real risk–free rate below the CGS indexed bond yields which are already an unreliablely low benchmark
- adopting an inflation forecast above the break even (market inferred) inflation can only be supported if it is assumed that the nominal CGS yields are distorted by the financial crisis.

CEG stated that the above inconsistencies could be addressed using one of the following approaches:[222]

- retain the nominal CGS as the proxy for the nominal risk–free rate but use the break even inflation rate where it is less than the inflation forecast based on RBA projections
- use 10 year indexed CGS to estimate the real risk–free rate and add RBA inflation projections to it to determine the nominal risk–free rate.

Submissions

SFG stated that, in the current market conditions, neither a break even inflation estimate nor an RBA based inflation forecast is likely to be precise and reliable.[223] SFG stated that,

216 AER, *Draft decision,* p. 96.
217 AER, *Draft decision*, p. 96.
218 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009.
219 TransGrid, *Revised revenue proposal,* pp. 57–60.
220 TransGrid, *Revised revenue proposal*, p. 61.
221 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 64–65.
222 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 65.

whichever inflation estimate is used, it should be applied consistently across the WACC parameters.

SFG stated that estimating inflation using RBA forecasts, while using nominal CGS yields to estimate the real risk–free rate results in an inconsistent estimation of WACC parameters, resulting in an estimate of the real risk–free rate that is implausibly low relative to the real risk–free rate implied by the yield on indexed CGS.

SFG stated that this inconsistency could be addressed using one of two approaches:[224]

- using the current yield on nominal CGS to estimate the nominal risk–free rate and using break even inflation implied by current yields on nominal and indexed CGS
- using the sum of indexed CGS yields and RBA inflation forecasts to estimate the nominal risk–free rate.

Similarly, Professor Grundy stated that, if the AER adopted an averaging period for the nominal risk–free rate that was close to the final decision date and used an inflation estimate based on RBA forecasts, the resulting real rate of return would be lower than the current yield on indexed CGS.[225]

Professor Grundy stated that using an inflation estimate based on the AER's methodology would only be credible if the AER's nominal risk–free rate estimate minus the AER's inflation estimate resulted in a real rate of return that was not less than the yield on indexed CGS. He stated that if this was not the case then the AER could use the yield on indexed CGS as the estimate of the real risk–free rate and add the AER's inflation estimate to this to set a nominal risk–free rate.[226]

AER considerations

In previous transmission determinations the AER has determined that a method that is likely to result in the best estimate of inflation over a 10–year period is to apply the RBA's short–term inflation forecasts—currently extending out to two years—and adopt the mid–point of its target inflation band beyond that period (i.e. 2.5 per cent) for the remaining eight years. An implied 10–year forecast is derived by averaging these individual forecasts.

The AER notes that TransGrid initially proposed an inflation forecasting methodology broadly similar to that applied by the AER in the draft decision and previous determinations,[227] based on advice from CEG.[228] In April 2008, CEG agreed with the AER's methodology and did not propose the use of the break even inflation method to estimate the expected inflation rate due to concerns over the reliability of indexed CGS yields.

---

223 SFG, p. 28.
224 SFG, p. 30.
225 Grundy B., pp. 23–24.
226 Grundy B., p. 25.
227 The difference between the AER's approach and CEG's suggested approach is the sources used to establish the 10 year inflation forecast. CEG's suggested approach drew on forecasts from a number of economic forecasters and the RBA's mid-point target band, while the AER relied on RBA inflation forecasts and the mid–point of its target band.
228 CEG, *Expected inflation estimation methodology*, April 2008.

The AER considers that, due to a lack of liquidity in the indexed CGS market, previous concerns over using the break even inflation rate to provide a best estimate of expected inflation remain valid. As outlined in the AER's 2007 SP AusNet draft decision,[229] the Australian Government has not issued indexed CGS since February 2003. This raised questions of liquidity in the indexed CGS market. The Australian Office of Financial Management, under direction of the Australian Government, has not reversed the decision to cease issuing indexed CGS and states that no further issuance is in prospect.[230] The AER therefore considers that the lack of supply and liquidity in the market for indexed CGS appears not to have abated.

The AER considers it reasonable to maintain its position that indexed CGS yields are not set in a well functioning market and do not reflect informed market opinion or future expectations of inflation. Therefore, the AER maintains the view of its previous determinations that the break even inflation rate, calculated as the difference between the yields on nominal and indexed CGS, will not provide a reliable or best estimate of inflation.

In January 2009, CEG stated that the global financial crisis has caused a 'flight to safety', resulting in such a high liquidity premium being paid for nominal CGS that, in the current market, exceeds the 'peace of mind' premium being paid for indexed CGS for inflation protection. CEG stated that if the AER's approach to inflation estimates is applied in these circumstances then it will make the estimate of the real risk–free rate less accurate and not more accurate.[231]

The AER notes that the real risk–free rate derived using the AER's inflation estimate will always differ from observed yields on indexed CGS because the break even inflation rate relies on the use of indexed CGS yields. As noted above, indexed CGS yields are not set in a well functioning market, which means that they do not reflect informed market opinion or an efficient outcome, and should therefore not be relied upon for deriving future inflation expectations or a real risk–free rate. The AER considers that CEG's conclusion on the relative movements of nominal and indexed CGS yields in the current market is unreasonable because any such conclusion will be tainted with the inefficiencies in the indexed CGS market.

The AER considers that CEG's suggested approach to use the break even inflation methodology where it is less than the RBA based inflation forecast[232] does not accord with the requirement under clause 6A.5.3(b) of the NER to apply the methodology that will result in the best estimate of expected inflation. Further, the AER has determined that the averaging period and the nominal risk–free rate that it has adopted is reasonable and the inconsistencies referred to by CEG are not valid due to inefficiencies in the indexed CGS market. Therefore, it is unnecessary to consider CEG's recommended solutions to the inconsistencies allegedly caused by using the risk–free rate averaging period that the AER has adopted.

---

229 AER, *Draft decision SP AusNet 2008–09 to 2013–14*, pp. 114–124.

230 AOFM, *Annual Report 2007/08 – Role of the Commonwealth Government Securities Market*, pp. 31, 116.

231 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 42

232 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 46, 65.

In estimating forecast inflation, the AER is guided by the NER requirement that the appropriate approach to forecasting inflation should be a methodology that the AER determines is likely to result in the best estimate of expected inflation.[233] In the absence of a credible market–based inflation forecasting methodology, the AER considers that the methodology adopted in the draft decision and recent AER determinations[234] remain appropriate for the purpose of determining the best estimate of expected inflation for this final decision. That is, adopting an average inflation forecast based on the RBA's short–term inflation forecasts and the mid–point of its target inflation band.

The AER recognises that inflation forecasts can change in line with market sensitive data. The recent change in short–term inflation expectations has been evident in the past six months, as demonstrated by the RBA's stance on monetary policy. In the draft decision the AER stated it would update the inflation forecast for its final decision. This is consistent with regulatory practice in Australia.

The AER has updated the inflation forecast for the first two years of the next regulatory control period using the latest published RBA inflation expectations as shown in table 4.5.[235] In its revised regulatory proposal, ActewAGL proposed that a geometric average instead of a simple average be used as it provides a more accurate approach to determining the average 10–year inflation forecast.[236] The AER recognises there is considerable uncertainty in forecasting inflation. Having assessed ActewAGL's revised regulatory proposal, the AER agrees that a geometric average may provide for a more accurate estimate of expected inflation during the forecast period. The AER also notes that the difference between applying a simple and geometric average is marginal. For consistency with the ACT distribution determination, the AER has applied a geometric average for the TransGrid transmission determination.

The AER considers that, consistent with its draft decision methodology and based on a geometric average, an inflation forecast of 2.47 per cent per annum produces the best estimate for a 10–year period to be applied in the post–tax revenue model for this final decision.

Table 4.5: AER conclusion on inflation forecast (per cent)

	June 2010	June 2011	June 2012	June 2013	June 2014	June 2015	June 2016	June 2017	June 2018	June 2019	Geometric average
Forecast inflation	2.75	2.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.47

Source: RBA, *Statement on monetary policy*, 6 February 2009, p. 65.

4.6 AER conclusion

The AER has determined a nominal vanilla WACC of 8.79 per cent for TransGrid, using an updated risk–free rate and debt risk premium, and other parameters prescribed under

233 NER, clause 6A.5.3(b)(1).

234 AER, *Final decision ElectraNet 2008–09 to 2012–13*, p. 69; and AER, *Final decision SP AusNet 2008–09 to 2013–14*, pp. 99–106.

235 RBA, *Statement of Monetary Policy*, 6 February 2009, p. 65.

236 ActewAGL, *Revised regulatory proposal*, January 2009, p. 49.

chapter 6A of the NER. Table 4.6 sets out the WACC parameter values used in this final decision. The AER's WACC is lower than TransGrid's revised revenue proposal WACC because of a lower nominal risk–free rate—commensurate with monetary policy and softening in economic growth—adopted for this final decision.

Table 4.6: AER conclusion on TransGrid's WACC parameters

Parameter	AER conclusion
Risk–free rate (nominal)	4.29%
Risk–free rate (real)[a]	1.77%
Expected inflation rate	2.47%
Debt risk premium	3.49%
Market risk premium	6.00%
Gearing	60%
Equity beta	1.00
Nominal pre–tax return on debt	7.78%
Nominal post–tax return on equity	10.29%
Nominal vanilla WACC	8.79%

(a) The real risk–free rate was calculated using the Fisher equation.

The AER considers that its decision to withhold agreement to the averaging period in TransGrid's revenue proposal is reasonable and that the agreed averaging period is consistent with finance theory, regulatory practice, the NER and NEL. The AER considers that the material provided by TransGrid in support of its revised revenue proposal does not justify that an averaging period prior to September 2008 is better than a period that is as close as practically possible to the start of the next regulatory control period.

The AER considers that only Bloomberg data should be used to estimate the debt risk premium based on its analysis of the fair yields reported by Bloomberg and CBASpectrum, observed yields of BBB+ corporate bonds and the methodologies adopted by these two data providers.

The AER maintains its draft decision to apply a methodology to determine a forecast inflation rate over a 10–year period using the RBA's inflation forecasts for the first two years and the mid–point of the RBA's target inflation range for the remaining eight years. The AER considers that, based on a geometric average, an inflation forecast of 2.47 per cent per annum produces the best estimate of a 10–year inflation forecast to be applied in the post–tax revenue model for this final decision.

5 Forecast operating expenditure

5.1 Introduction

This chapter sets out the AER's assessment of TransGrid's opex proposal for the next regulatory control period. The AER has reviewed TransGrid's opex proposal against the requirements of the NER.

The opex forecasts in TransGrid's proposal refer to its requirements for the provision of prescribed transmission services in the next regulatory control period.

5.2 AER draft decision

The AER was not satisfied that TransGrid's proposed opex forecast reasonably reflected the opex criteria as set out in the NER, taking into account the opex factors. Accordingly, the AER did not accept the forecast opex in TransGrid's revenue proposal.[237]

On the basis of its analysis of TransGrid's proposed opex forecast and the advice of PB, the AER applied a reduction of $90 million ($2007–08) to TransGrid's proposed opex allowance. This represented a reduction of around 11 per cent of TransGrid's proposed opex of $855 million and resulted in an amended forecast opex allowance of $765 million.[238] Table 5.1 shows the total opex allowance by expense category.

Table 5.1: AER draft decision on TransGrid's opex forecast ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's proposed controllable opex	135.2	144.4	149.7	161.8	166.5	757.6
Debt raising costs	3.7	4.0	4.3	4.8	5.1	22.0
Equity raising costs	0.9	1.7	3.1	4.0	4.2	13.9
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance	3.2	3.2	3.2	3.2	3.2	15.9
TransGrid's total opex	164.5	159.2	166.3	179.8	185.0	854.8
AER controllable opex	128.4	135.7	139.5	147.9	149.9	701.3
Debt raising costs	1.9	2.1	2.2	2.4	2.6	11.2
Equity raising costs	–	–	–	–	–	–
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance	1.4	1.4	1.4	1.4	1.4	6.8
AER total opex	153.2	145.1	149.0	157.6	159.8	764.8

Source: AER, *Draft decision*, p. 147.

237 AER, *Draft decision*, p. 146.
238 The forecast opex allowance is $805 million in 2008–09 dollar terms.

5.3 Revised revenue proposal

TransGrid implemented the draft decision in respect of forecast opex except in relation to:[239]

- labour cost escalators
- defect maintenance expenditures for new growth assets
- self insurance costs
- debt raising costs
- equity raising costs.

TransGrid's revised opex forecast proposal is $810 million ($2007–08) as set out in table 5.2.

Table 5.2: TransGrid's revised opex forecast ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's revised controllable opex proposal	128.5	138.4	142.7	152.5	155.7	717.8
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Debt raising costs	3.7	4.0	4.3	4.7	5.0	21.7
Equity raising costs[a]	1.1	1.9	3.0	3.8	3.8	13.6
Self insurance	2.2	2.2	2.2	2.2	2.2	11.0
TransGrid's revised total opex proposal	157.1	152.5	158.2	169.1	172.7	809.6

Source: TransGrid, *Revised revenue proposal*, p. 83.
(a) The proposed equity raising cost allowance does not include an estimate for retained earnings. TransGrid's cash flow modelling provided with its revised revenue proposal PTRM calculated total equity raising costs of $38 million ($2007–08).

5.4 Submissions

The AER received the following submissions:

- Powerlink discussed defect maintenance, debt and equity raising costs and self insurance costs[240]
- the Energy Users Association of Australia (EUAA) commented on labour escalators, defect maintenance, the Demand Management and Planning Project (DMPP), cost allocation of overheads and network support pass throughs[241]
- TransGrid discussed defect maintenance.[242]

[239] TransGrid, *Revised revenue proposal*, p. 66.
[240] Powerlink, 16 February 2009, p. 2.
[241] EUAA, p. 13.

5.5 Consultant review

The AER engaged the following consultants to assist with its consideration of TransGrid's opex:

- PB reviewed the additional information on defect maintenance for new assets provided by TransGrid in its revised revenue proposal
- Econtech advised the AER on labour cost escalators
- Associate Professor John Handley from the University of Melbourne advised the AER on debt and equity raising transaction costs.

5.6 Issues and AER considerations

5.6.1 Labour cost escalators

5.6.1.1 Electricity, gas and water and general labour escalators

AER draft decision

The AER engaged Econtech to provide advice on labour cost growth forecasts in NSW. The AER was satisfied that Econtech's wage growth forecasts for the electricity, gas and water (EGW) sector were robust and applied these forecasts for the next regulatory control period. In applying Econtech's forecasts, the AER did not accept TransGrid's proposal, which was based on advice from the Competition Economists Group (CEG), to apply an average of Econtech (published in 2007) and Macromonitor EGW labour growth forecasts.[243]

Revised revenue proposal

TransGrid did not accept the EGW labour escalators applied by the AER in its draft decision. TransGrid re–engaged CEG to review the draft decision. CEG considered that while the AER's approach was largely reasonable, it had concerns with the timing calculations applied in the draft decision. Specifically:

- Econtech's forecasts for EGW wages growth were in financial year average terms, and not in June to June terms
- the Award rate was not correctly timed to interpolate to EGW rates, resulting in the model double counting inflation for some years.

As a result, CEG proposed revised EGW wages labour escalators, based on the Econtech forecasts applied by the AER in its draft decision, to address these concerns.

CEG raised issues with the application of updated EGW labour escalators after TransGrid lodged its revised revenue proposal. CEG considered that if the AER was to seek an update from Econtech for EGW labour cost growth rates, it would be described as

---

[242] TransGrid, *Submission to the AER on EUAA comments*, p. 4.
[243] AER, *Draft decision*, p. 252.

re–doing a forecast, rather than updating a forecast in accordance with an agreed methodology.[244]

TransGrid based on advice from CEG, considered that if the AER re–engaged Econtech to update its forecasts, then the AER should also undertake further consultation with TransGrid.[245]

Submissions

The EUAA submitted:[246]

- that the AER should refresh its labour cost escalation assumptions in light of the recent economic collapse and global downturn
- expected real wage increases should ultimately be discounted for normal increases in labour productivity
- the past commodity boom and labour shortages are no longer realistic assumptions for the next regulatory control period.

Consultant review

The AER engaged Econtech to provide an update on its wage forecasts for the EGW sector in NSW. In preparing its labour costs growth forecasts, Econtech took account of the latest available wage data.

Econtech's updated forecasts for labour cost growth rates in the EGW sector across NSW for the next regulatory control period is shown in table 5.3 and outlined in further detail in appendix A of this final decision.

Table 5.3: Econtech's real EGW labour escalation rates for NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
EGW wages	1.3	–0.7	3.3	3.6	2.4	1.7	0.6

Source: Econtech, *Updated labour cost growth forecasts for the AER*, 25 March 2009, p. 28.

AER considerations

Updated labour cost escalators

The details of the AER's assessment of the labour cost growth forecasts proposed by TransGrid are set out in appendix A of this final decision.

The AER notes submissions relating to labour cost escalators discussed changing economic conditions and that the labour cost escalators applied in the draft decision are now out of date. The AER engaged Econtech to provide updated labour cost escalators

244 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 13.

245 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 14.

246 EUAA, pp. 13, 17.

based on the most recent available data.[247] The AER considers that the updated forecasts take account of the current economic slowdown.

The AER considers that CEG's recommendations regarding the appropriate timing of the escalators the AER applied in the draft decision are reasonable. The AER has implemented CEG's recommendations to TransGrid's labour escalators by making refinements to its cost escalations model to ensure the Award rates are appropriately timed with forecast EGW rates to alleviate issues of double counting CPI. The AER has addressed this by creating an index of real wage rates, as recommended by CEG.

The AER has identified an error in CEG's model which mistimes the application of Econtech's EGW wage rates by applying a financial year's data to a calendar year—this effectively means CEG has been using Econtech's labour rates six months before the period in which they should be applied. The AER has corrected this error as part of the adjustments made for the appropriate timing of escalators in its model.

The AER notes that TransGrid, based on advice received from CEG, accepted the use of Econtech's forecasts in the draft decision as reasonable, subject to the AER rectifying the specified timing issues.[248] The AER further notes TransGrid's concerns with Econtech updating its forecasts after TransGrid's revised revenue proposal was submitted. To ensure a robust and transparent process on the updating of labour wage growth forecasts, the AER engaged in a briefing with TransGrid, where Econtech provided an overview of its economic models used to derive the labour wage growth forecasts and the economic assumptions underlying its updated forecasts. The AER also outlined refinements to its cost escalations model from the draft decision.

For this final decision, the AER adopted Econtech's updated wage growth forecasts for the next regulatory control period. It also re–modelled the forecasts to address CEG's timing issues and applied these updated forecasts for the EGW sector in NSW for the next regulatory control period. Actual wage data, however, was available for 2007–08 and 2008–09, and therefore the AER has applied actual wage increases for those years, which have also been remodelled to address the timing issues.

The EGW labour cost growth forecasts the AER will apply to TransGrid's opex for the next regulatory control period are shown in table 5.4.

Table 5.4: AER conclusion on TransGrid's real EGW labour escalation rates (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Award/EGW wages	1.69	0.84	3.27	3.60	2.40	1.70	0.60

Application of updated labour cost escalators

In the draft decision the AER accepted the application of EGW labour cost escalators by TransGrid to its forecast opex. Following a request from the AER to apply the updated

247 New forecasts incorporate data published by the Australian Bureau of Statistics, including Average Weekly Earnings (released 26 February 2009) and National Accounts (released 9 March 2009).

248 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, pp. 7–12.

Econtech EGW wage growth forecasts, TransGrid advised that the AER's conclusions result in a reduction of $12 million ($2007–08) to its opex forecast.[249]

AER conclusion

As a result of the AER's analysis of the revised revenue proposal, the AER is satisfied that the application of updated EGW labour cost escalators for NSW (as set out in table 5.4), within TransGrid's opex model results in forecast opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

5.6.2 Defect maintenance for new growth assets

AER draft decision

The AER considered that the defect maintenance expenditure forecast proposed by TransGrid was not reasonable because it did not factor in the significant increase in new assets to be commissioned during the next regulatory control period.[250] Accordingly, the AER did not include an allowance for defect maintenance costs for those assets which are to be commissioned during the next regulatory control period. This adjustment resulted in a reduction of $15 million ($2007–08) to the forecast controllable opex for the next regulatory control period.[251]

Revised revenue proposal

TransGrid rejected the draft decision not to include an allowance for defect maintenance costs for those assets which are to be commissioned during the next regulatory control period.[252] TransGrid engaged Sinclair Knight Merz Pty Ltd (SKM) to provide an assessment of PB's review of TransGrid's asset growth escalation. With the support of a report from SKM[253] TransGrid identified three issues which led it to conclude that it was unreasonable for the AER to reduce the allowance for defect maintenance.

TransGrid responded to the AER's position that TransGrid's defect maintenance expenditure failed to factor in the significant increase in new assets proposed to be commissioned. TransGrid provided a graph that supported its position that the average age of assets is reasonably stable over the current and next regulatory control periods.[254] TransGrid therefore concluded that the defect rates would not be impacted by the effect of any new assets.[255]

TransGrid considered that new assets can experience higher defect costs than for mid–life equipment—for example, as a result of manufacturing defects.[256] TransGrid included a graph in its revised revenue proposal, which it claimed shows that defect costs for newer assets are significantly higher across all the asset categories.[257] SKM's report

249 TransGrid, *Response to issue number 341*, 16 April 2009.
250 AER, *Draft decision*, p. 126.
251 This includes adjustments for labour cost escalators and amended asset growth.
252 TransGrid, *Revised revenue proposal*, p. 66.
253 SKM, *Considerations on PB's Review of TransGrid's Operating Expenditure*, 19 December 2008 (attached as appendix L of TransGrid's revised revenue proposal).
254 TransGrid, *Revised revenue proposal*, pp. 69–70.
255 TransGrid, *Revised revenue proposal*, p. 69.
256 TransGrid, *Revised revenue proposal*, p. 71.
257 TransGrid, *Revised revenue proposal*, pp. 71–72.

also indicated that manufacturing defects on new equipment, combined with design and installation errors will result in additional costs incurred by the equipment owner.[258]

Finally, TransGrid and SKM commented on the warranties that cover some of the defect rectification work. SKM noted that the defects liability period and associated warranty are intended to mitigate the risk to the asset owner for omissions and faults caused by the manufacturer in its design/installation and commissioning of the equipment.[259] However, SKM noted that defects of any kind will result in some costs incurred by TransGrid which are not recoverable from the manufacturer.[260] TransGrid stated that while warranties do provide limited coverage, warranties do not cover the emergency response, fault detection and site supervision components of any equipment malfunction.[261]

Submissions

The EUAA agreed with the draft decision that the forecast defect maintenance is not reasonable because it does not factor in the significant increase in new assets proposed to be commissioned during the next regulatory control period and accordingly, supported the reduction to the opex allowance.[262]

Powerlink disagreed with the AER's decision not to allow defect rectification costs on new assets, with the exception of those identified and rectified during the warranty period.[263] TransGrid made a submission that its revised revenue proposal demonstrates that new assets do not come 'free' of opex obligations and this was supported by a review of opex maintenance by SKM.[264]

Consultant review

In its report, PB addressed the key points which TransGrid relied on to support its proposal that the defect maintenance should not be reduced. PB's considerations are set out below.

No significant change to the age mix of assets

PB noted that at a macro level TransGrid's analysis of the system average age is correct as the ratio of new assets proposed to be constructed during the next regulatory control period compared to the number of assets in the existing asset base is very small.[265]

PB stated that the average maintenance costs associated with new assets should be lower than for assets commissioned in preceding regulatory control periods and hence PB would also expect lower defect rectification expenditures for several years after the initial warranty period has expired. PB considered that the TransGrid opex model tends to overstate the defect rectification expenditures required for newly commissioned assets. As such, PB recommended adjusting the forecast opex associated with assets commissioned during the next regulatory control period.[266]

258 SKM, p 3.
259 SKM, p. 4.
260 SKM, p. 6.
261 TransGrid, *Revised revenue proposal*, p. 69.
262 EUAA, p. 17.
263 Powerlink, 16 February 2009, p. 2.
264 TransGrid, *Submission to the AER on EMRF comments*, 16 February 2009, p. 4.
265 PB, p. 71.
266 PB, p. 71.

Accordingly, PB maintained that reductions in opex associated with reduced defect related activities due to the installation of new assets should be factored into the forecast opex.

New assets experience higher defect rates

PB considered that new specialist electricity plant and equipment procured in accordance with recognised standards from established manufacturers will generally experience minimal if any defects for several years following successful commissioning and expiry of warranty periods.[267]

PB also noted that TransGrid excludes some non–routine and condition–based tasks such as substation cleaning and ground maintenance from its routine maintenance forecasts which are instead included in TransGrid's opex category of 'defect maintenance'. PB stated that generally this type of maintenance is considered to be routine in nature.[268]

PB noted TransGrid's use of the 'bathtub curve'[269] and agreed with SKM that new assets incur higher rates of defects than mid–life equipment.[270] PB noted that many defects will be repaired by the manufacturer within the warranty period—this was consistent with SKM's position (although SKM concluded that TransGrid's defect rate was appropriate).[271] PB considered that after the warranty period, new assets generally have fewer defects than older assets and this is supported by the SKM perspective.[272]

PB noted SKM's view that some new equipment requires modification or adjustment to ensure suitable operation and reliability. PB stated it does not consider a capital project is complete until it is fully commissioned with all equipment functioning as originally specified. The capital cost of a project should include all costs incurred until the project is operating in accordance with its design criteria. Therefore, PB considered that any associated works carried out after practical project completion should be very minor in nature and of insignificant value.[273]

PB provided comment on figure 5.3, 'Defect ratio vs commissioning date',[274] (reproduced below at figure 5.1) of TransGrid's revised revenue proposal.[275] While recognising the limited data in the survey period, PB stated that figure 5.1 demonstrates that TransGrid's analysis of defect ratios calculated on a cost basis for the first three years of the current regulatory control period are significantly higher than the long–term averages and not aligned with historical trends.[276] PB stated that an examination of the underlying data shows the material increase is a combination of smaller than normal spends on routine

---

267 PB, p. 72.

268 PB, p. 72.

269 The bathtub curve or a failure rate over time graph demonstrates that new assets and old assets are more likely to suffer from higher rates of defects than assets in their mid–life.

270 PB, p. 72 and SKM, p. 3.

271 PB, p. 72 and SKM, p. 3.

272 PB, p. 72 and SKM, p. 3.

273 PB, p. 73.

274 Defect ratio is a measure that calculates the defect cost to routine cost ratio; Source: TransGrid, *Response to issue number 299*, 2 February 2009.

275 TransGrid, *Revised revenue proposal*, p. 72.

276 PB, p. 74.

maintenance and higher than normal spends on defect rectification compared with historical spending patterns.[277]

PB also asked TransGrid to rework the data to exclude the impacts of one–off events such as the Haymarket substation—the reworked graph is reproduced below at figure 5.2.[278] PB concluded that generally the revised data shows a reduction in total asset defect ratios for a given commissioning date over the current regulatory control period based on costs incurred during the 2006–07 to 2007–08. Even though the survey period was limited to two years data, PB noted that this figure demonstrates that the substation defect ratio has consistently been lower for equipment commissioned since 1990–94. PB did not consider that extending the survey period would change the trends evident by the reworked data.[279]

PB considered that the downwards trend of the total defect data (shown at figure 5.2) and the decline in the average switch bay maintenance cost trend provides support for its position that newly commissioned assets experience lower average maintenance costs than assets commissioned in previous regulatory control periods.[280]

Warranties provide limited coverage

PB considered that the warranty periods identified by SKM should be sufficient to identify and/or detect any burn–in, material, workmanship, design or construction issues during the warranty period and have them rectified at the expense of the manufacturer or the supplier.[281] PB noted that TransGrid could incur some minor costs, which would not be recoverable from the manufacturer, in providing some labour to remove and replace faulty equipment.[282]

SKM also identified a list of costs that TransGrid will likely incur which are non–recoverable from the manufacturer. In relation to these non–recoverable costs, PB considered that:[283]

- some of these costs should be included in TransGrid’s technical overheads such as the liaison with manufacturers to determine effective solutions
- other costs should be included in allowances made for system operation such as outage planning, management and control room switching costs
- some costs should be so small and incremental as to be insignificant (such as customer interruptions and impacts on service standards)
- supervision and support costs should also be relatively minor.

PB also noted that TransGrid excludes some non–routine tasks such as lawn mowing and substation cleaning from its routine maintenance forecasts. These are included in TransGrid’s category of ‘defect maintenance’ PB noted that some of these minor costs (including non–routine tasks) would not be recoverable from manufacturers and therefore

277 PB, p. 74.
278 TG, *Response to issue 311 (B1) and (B2)*, 18 February 2009, p. 5. These assets are technically different to TransGrid’s other assets as they include unique underground SF_6 insulated transformers and switchgear.
279 PB, pp. 74–75.
280 PB, p. 75.
281 PB, p. 77.
282 PB, p. 78.
283 PB, p. 80.

included an adjustment to its original recommended position to compensate for such costs.[284]

In its report, PB reproduced graphs which TransGrid provided in response to requests for further information. These graphs, included as figures 4.8 and 4.9 in PB's report,[285] indicate that average maintenance costs per switchbay are lower for newly commissioned assets than for assets commissioned during previous regulatory control periods over the sampled period 2006–07 to 2007–08. Further, the average maintenance costs for switchbays displays a reducing trend for assets commissioned over the last thirty years during the review period.[286] PB considered that this supported its assertion that newly commissioned assets have lower average maintenance costs than older assets, implying lower defect rectification costs than older assets.[287]

TransGrid provided details of defect costs it incurred which were non–recoverable from manufacturers that were associated with the defect rectification of newly commissioned assets.[288] PB reviewed the information and, on the assumption that it is based on full year results and that the same burden factors were used, noted that:[289]

- there were unexplained increases in expenditure from year to year
- even after the expiry of warranty periods, the average defect cost per substation switchbay is higher than the network average (by about 40 per cent).

PB noted that the data is not consistent with its experience as generally after the initial warranty period, the number of defects for newly commissioned equipment is lower than the average for the network.[290] PB also considered that the data showing the average defect cost per switchbay appears disparate compared with the average maintenance costs for switchbays commissioned during the current period (excluding Haymarket). PB therefore considered that the data provided by TransGrid does not align with PB's expectations and was not supported by appropriate rationale.[291]

PB maintained its recommendation to reduce the total costs forecast by TransGrid's opex model to reflect the impact of the expected lower maintenance costs associated with new assets proposed in the significant capital works program. PB recommended this be done by quantifying the defect rectification costs for growth related assets using the TransGrid model.[292] This approach is consistent with that used by the AER in the draft decision.

PB recommended that TransGrid be provided a defect rectification allowance for the non–routine but regular maintenance costs such as lawn mowing, garden maintenance and substation cleaning which are included in TransGrid's defect rectification forecasts. PB also considered that the minor costs associated with organising and managing works which are not recoverable from manufacturers should be included in this defect

284 PB, p. 78.
285 Figures 4.8 and 4.9 have been extracted from responses to AER and PB queries: TransGrid, *Response to issue 311 (B1) and (B2)*, p. 4.
286 PB, pp. 78–79
287 PB, p. 79.
288 TG, *Response to issue 311 (B3)*, 20 February 2009, pp. 1–2.
289 PB, p. 81.
290 PB, p. 81.
291 PB, p. 82.
292 PB, p. 83.

rectification allowance. In the absence of specific data to support the magnitude of these costs, PB considered that an allowance of $300 000 ($2007–08) per year over the next regulatory control period is a reasonable amount to provide TransGrid for these costs.[293]

AER considerations

In making its final decision on defect maintenance costs for new assets the AER has considered the three key issues raised by TransGrid and reviewed by PB.

No significant change to the age mix of assets

The AER considers that the critical issue in respect of providing TransGrid an allowance for defect expenditure is the impact the addition of new assets will have on defect maintenance.

In this regard, the AER notes that TransGrid provided data that demonstrates that its forecast capex will have minimal impact on the system average age. TransGrid concluded that as the average age is reasonably stable, there would be no expectation that defect rates would be impacted by the effect of any new assets.

The AER notes that the system average age is not a point of contention for PB. The AER considers that TransGrid has demonstrated the system average age will remain stable. However, the AER does not consider that TransGrid has demonstrated that the result of a stable system average age is that the defect rates will not be impacted by new assets.

The AER notes PB's position that the average maintenance costs associated with new assets are lower than for assets commissioned in preceding regulatory control periods. Further, PB considered it reasonable to expect this would result in lower defect rectification expenditures for several years after the initial warranty period has expired.

While the AER notes TransGrid's claim that the likely impact of new assets is not sufficient to reduce the system average age significantly, the AER accepts PB's advice that the introduction of new assets is likely to lead to reduced defect rectification expenditures after the warranty period expires. The AER notes PB's view that as TransGrid's opex model uses system average ages to forecast future operational expenditure it tends to overstate the defect rectification expenditures required for newly commissioned assets.

Accordingly, the AER considers it appropriate to adjust downwards TransGrid's forecast opex associated with assets expected to be commissioned during the next regulatory control period. This is consistent with the conclusion reached in the draft decision.

New assets experience higher defect rates

The AER notes TransGrid's assertion (supported by figure 5.1 below) that rather than new assets showing a significant reduction in defect costs, the defect costs for newer assets are significantly higher across all the asset categories.[294] SKM stated that new assets incur higher rates of defect than mid–life assets.[295] Similarly, Powerlink submitted that new assets do suffer from 'teething' problems or 'infant mortality'.

293 PB, p. 83
294 TransGrid, *Revised revenue proposal*, p. 71.
295 SKM, p. 3.

The AER notes that PB agreed that new assets do incur higher rates of defects than mid–life assets. However, PB considered higher rates of defect for new assets primarily result from manufacturing defects, 'burn–in' failures and design and installation errors, which are usually rectified well within the standard warranty periods. PB also considered that new specialist electricity plant and equipment procured in accordance with recognised standards from established manufacturers will generally experience minimal if any defects for several years following successful commissioning and expiry of warranty periods.[296]

The AER recognises TransGrid's position that there may be more defects and a need to modify or make adjustments to assets at the start of an asset's life. However, the AER notes that both SKM and PB considered that these are likely to occur within the warranty period.[297] SKM considered that certain defect rectification will be attributable to the manufacturer under the warranty but that there may be additional costs to TransGrid which are not recoverable from the supplier.[298] PB agreed with SKM that there will be some costs which are not recoverable under the warranty from the supplier. The AER notes that PB recommended an allowance for these costs which is discussed further below.

The AER also notes SKM's view that within the mid–life/random failure zone, newer equipment will tend to have fewer defects than older equipment.[299] This is consistent with PB's view that after the expiry of warranty periods, new assets experience lower maintenance costs than assets commissioned during previous regulatory control periods.[300]

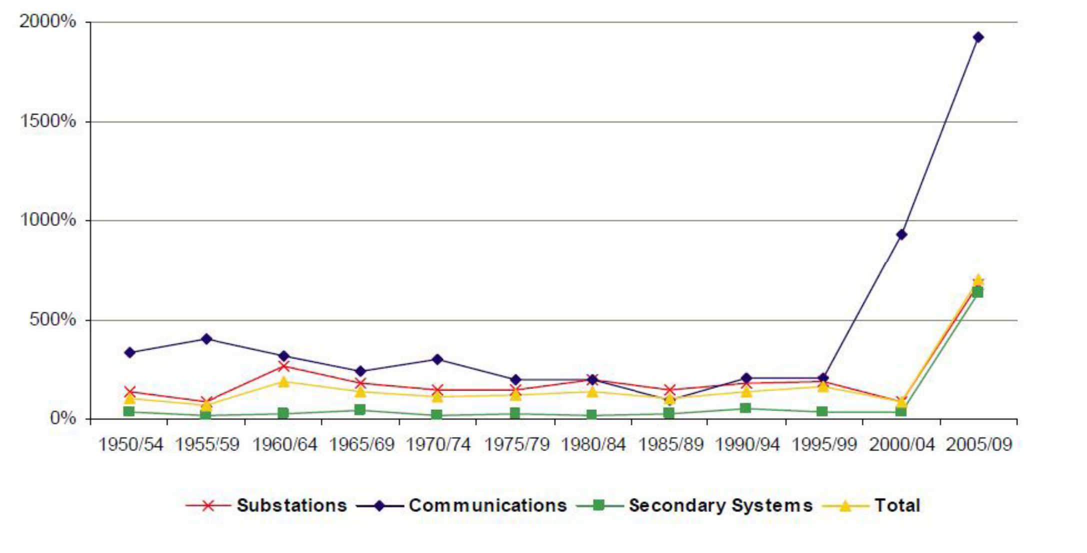
As such, the AER considers that while TransGrid will incur some non–recoverable costs, the majority of these defects occur within the warranty period and are rectified at the expense of the manufacturer or supplier. The AER is further satisfied that after the warranty period has expired, new assets procured in accordance with recognised standards from established manufacturers are likely to incur minimal, if any, defects for several years.

The AER and PB reviewed the data provided by TransGrid. Figure 5.3 of TransGrid's revised revenue proposal (reproduced at figure 5.1) shows the long–term trend of defect ratios across asset classes. Figure 5.2 is a reworked version by TransGrid of figure 5.1—it excludes the impacts of the Haymarket substation defects associated with the MetroGrid project. Figure 5.1 shows significant step changes in 1995–99 and 2000–04 and suggests defect maintenance in earlier years was greater than previously indicated. In response to questions regarding figure 5.1 TransGrid stated:[301]

> In the case of 1995–1999 this is associated with a single substation commissioned in this period, on which the total expense in the survey period was less than $2000. Routine maintenance costs in this period were only $78, leading to an unrepresentative defect ratio.

296 PB, p. 72.
297 SKM, p. 3; PB, p. 72.
298 SKM, p. 3.
299 SKM, p. 3; PB, p. 72.
300 PB, p. 72.
301 TransGrid, *Response to issue 311 (B1) and (B2)*, pp. 1–2.

Figure 5.1: Defect ratio vs. commissioning date



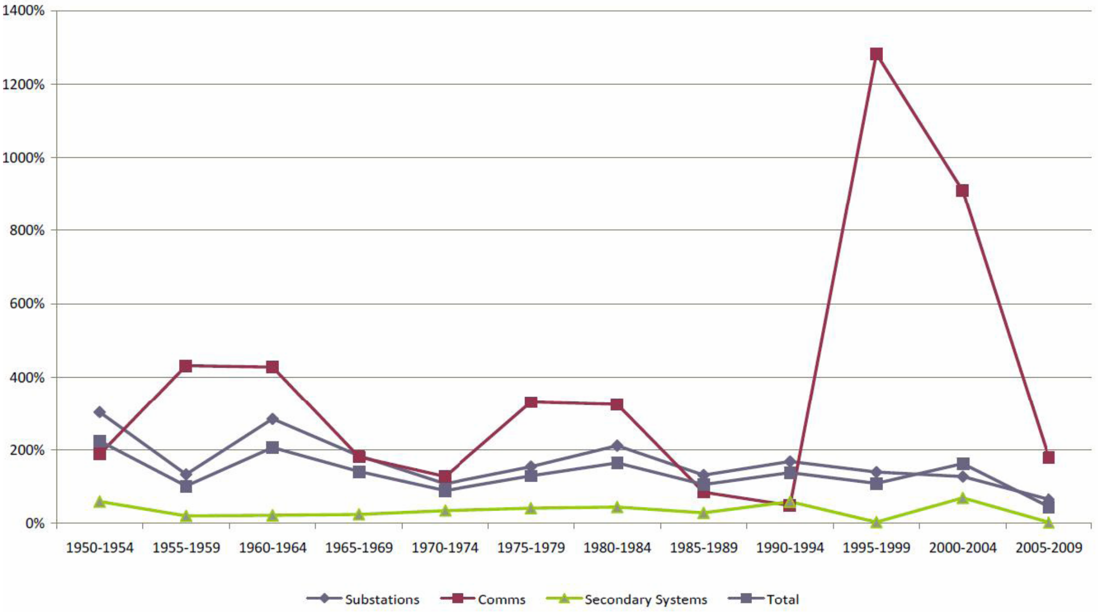
Source: TransGrid, *Response to information request number 311 (B1) and (B2)*, p. 5.

The AER notes PB's position that the input data indicates that the step changes are largely attributable to significantly less expenditure on routine maintenance and higher than normal spends on defect rectification compared with historical spending patterns rather than a significant increase in expenditure on defects. The AER considers that the data relied upon by TransGrid does not demonstrate that new assets experience higher defect costs payable to TransGrid than mid–life assets.

In addition, the AER notes that after one–off items are removed, figure 5.2 demonstrates a likely reduction in asset defect ratios for new assets over the current regulatory control period. Accordingly, the AER accepts PB's advice that the downwards trend of the total defect data and the decline in the average switchbay maintenance cost trend indicates newly commissioned assets experience lower average maintenance costs than assets commissioned in previous regulatory control periods.

Having reviewed the material put forward, the AER considers that at the start of an asset's life there may be a need to modify or make adjustments. The AER considers, however, that maintenance costs associated with defects of new assets should occur within the warranty period and are therefore attributable to the manufacturer. Following the warranty period, newly commissioned assets would experience lower defect rectification costs than assets commissioned in previous regulatory control periods. Accordingly, while the AER notes that new assets may have higher defect rates than mid–life assets, overall, this does not imply higher defect costs attributable to TransGrid.

Figure 5.2: Defect ratio vs. commissioning date (excluding Haymarket data)



Source: TransGrid, *Response to information request number 311 (B1) and (B2)*, p. 5.

Warranties provide limited coverage

The AER notes that SKM considered that certain defect rectification will be attributable to the manufacturer under the warranty but that there may be additional costs to TransGrid which are not recoverable from the supplier.[302] SKM outlined the type of costs for which TransGrid is likely to be liable even though there may be warranties in place.[303]

The AER notes PB considered that most defect costs (including modifications and adjustments) should be borne by the manufacturer during the warranty period.[304] PB considered that some of the items identified by SKM should be attributed to other areas of expenditure. However, PB noted that TransGrid is still likely to incur some minor costs such as organising and managing works which are not recoverable from the manufacturer or supplier.[305] PB also noted that TransGrid included some non–routine tasks such as lawn mowing and substation cleaning in its defect maintenance opex category which would usually be considered to be routine in nature.

Based on PB's advice and SKM's views, the AER considers that warranties are effective in transferring most of the liability for defects in new assets to the manufacturer. The AER accepts PB's advice that some of the costs that are non–recoverable under warranties are allocated to other areas of expenditure. However, the AER also accepts the views of SKM and PB that there are likely to be some non–recoverable costs which TransGrid will incur.

The AER notes that TransGrid provided details of defect costs it incurred which were non–recoverable from manufacturers. There are unexplained increases from year to year on these costs. The AER accepts PB's advice that the data does not align with PB's

302 SKM, p. 3.
303 SKM, p. 6.
304 PB, p. 77.
305 PB, p. 78.

expectations and the irregularities are not supported by appropriate rationale.[306] Therefore, the AER is not satisfied that the data can be relied on to substantiate TransGrid's claims of higher defect maintenance expenditures.

The AER notes that the magnitude of the expenditure required for non–routine tasks as well as non–recoverable costs may be minor. However, under the NER, TransGrid is entitled to receive an allowance for such expenditure in its opex forecast. The AER notes that no reasonable forecasts of such expenditures have been provided. The AER accepts PB's advice that an amount of $300 000 per year over the next regulatory control period is a reasonable allowance for these costs.[307] The AER considers that this amended opex allowance will be sufficient for TransGrid to meet the non–recoverable and non–routine costs.

AER conclusion

The AER has reviewed the information put forward and considers that TransGrid's system average age is relatively stable over the next regulatory control period but this does not imply that the defect rate will remain stable. Based on the advice of PB, the AER accepts that overall, TransGrid is experiencing lower average switchbay maintenance costs for newly commissioned assets compared to assets commissioned during previous regulatory control periods. While TransGrid may incur some costs associated with defects of new assets, warranties should result in other parties being responsible for the majority of the defect costs during the burn–in period. Following the warranty period, the defect rate on new assets should have reduced to a lower level than the overall average.

The AER accepts PB's advice that TransGrid will incur some non–recoverable costs from organising and managing new works. Further, TransGrid has allocated some non–routine maintenance tasks such as lawn mowing, garden maintenance and substation cleaning to the opex category of defect maintenance and therefore has not otherwise received an allowance for these costs. The AER has accepted PB's recommendation to provide TransGrid with an allowance of $300 000 per year over the next regulatory control period for these costs.

For the reasons discussed and as a result of the AER's analysis of the revised revenue proposal and additional information, the AER is not satisfied that the inclusion of the total proposed defect maintenance for new growth assets to TransGrid's opex forecast results in expenditure which reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors. Following a request from the AER, TransGrid advised that the removal of the allowance for defect maintenance results in a reduction of $15 million ($2007–08) to its forecast opex.[308] The inclusion of an allowance of $1.5 million for some non–recoverable and non–routine costs results in an overall net reduction to the forecast opex of $14 million.

---

306 SKM, p. 3.
307 PB, p. 83.
308 TransGrid, *Response to issue number 341*, 16 April 2009.

5.6.3 Self insurance

AER draft decision

In the draft decision, the AER accepted TransGrid's proposed allowances for self insurance for the following risks:[309]

- fraud risk
- insurers' credit risk
- counterparty credit risk
- risk of non–terrorist impact of planes and helicopters.

The AER indicated that for other risks it was not satisfied that TransGrid, based on the advice from SAHA International Limited (SAHA),[310] had provided robust analysis which supported the probability of an event occurring or the costs associated with the event.[311] This meant that the calculation of the self insurance premium could not be relied upon.[312] The AER considered that TransGrid's proposed self insurance allowances did not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, or a realistic expectation of those costs, and made adjustments accordingly. The AER reduced TransGrid's self insurance allowance to $6.8 million from $16 million ($2007–08) for the next regulatory control period.[313]

Revised revenue proposal

TransGrid did not accept the reductions to the self insurance allowance determined by the AER and commissioned SAHA to respond to the draft decision.[314]

SAHA prepared a generic report in relation to self insurance costs for TransGrid, ActewAGL, Country Energy, EnergyAustralia and Integral Energy.[315] SAHA provided comments regarding the AER's assessment of self insurance and a response to the AER's rejection of allowances for each of the businesses.

AER approach to assessing self insurance premiums

TransGrid stated that the AER made a number of errors in relation to its treatment of self insurance costs. In particular, the AER has:[316]

- misunderstood the nature of expected values and how they are calculated

309 AER, *Draft decision*, p. 283.

310 SAHA provides strategic, commercial, economic, corporate finance and financial consulting services. See SAHA website http://www.sahainternational.com/SAHA/SERVICES/pc=PC_90006.

311 AER, *Draft decision*, p. 283.

312 SAHA, *TransGrid – Self Insurance Risk Quantification, Final Report*, confidential, 20 May 2008; and SAHA, *TransGrid – Self Insurance Risk Quantification, supplementary report–response to AER/PB*, confidential, 5 August 2008.

313 AER, *Draft decision*, p. 136.

314 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, 14 January 2009.

315 Each of these businesses proposed self insurance allowances in their revenue/regulatory proposals and engaged SAHA to determine the original risk estimates and associated self insurance premiums. Since many of the issues raised in the AER's draft decisions in relation to self insurance are similar across these businesses, SAHA provided a single report in response.

316 TransGrid, *Revised revenue proposal*, p. 74.

- not shown that the self insurance claims (supported by actuarial verification) are not reasonable
- when rejecting TransGrid's calculation of risk exposure, it has not provided its own estimate of costs where probabilities of events are non–zero.

TransGrid noted that the AER assessed its self insurance estimate to satisfy the objective that the costs 'reasonably reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives'. TransGrid considered that the term 'reasonably reflects' should be a function of whether a 'reasonable practitioner', faced with a similar situation, would adopt a similar approach to undertaking the risk quantifications.[317]

TransGrid indicated that, as per SAHA's approach, risk specialists leverage all available relevant data, along with their reasonable judgement, to provide a best estimate of the probability and consequence for that event. Further, TransGrid noted that risk specialists do not limit their valuation only to risks that have affected the company previously, which appeared to be a key assumption of the AER's argument.[318]

SAHA stated that the AER appears to have adopted a number of sub–criteria in assessing whether the self insurance premiums reasonably reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.[319] SAHA considered that these sub–criteria appear to include that a zero self insurance risk allowance will more reasonably reflect the efficient costs that a prudent operator would incur than SAHA's valuation when:[320]

- that business has never borne a cost resulting from the risk
- the historical data supporting the derivation of that risk is deemed to be for a period that is not long enough
- qualitative evidence has been used to support a risk quantification, even if this qualitative evidence is used in conjunction with quantitative evidence
- the quantification relies on data derived from similar events that have affected other electricity businesses.

Further, SAHA suggested that efficient estimates can be derived in the absence of perfect historical data and that 'reasonable practitioners' adopt similar approaches to those used by SAHA in order to determine premiums in the absence of such data.[321] SAHA stated that these practitioners leverage off available information and use professional judgement to determine premiums.[322] SAHA also stated that its self insurance estimates were reviewed by an actuary.[323]

317 TransGrid, *Revised revenue proposal*, pp. 74–75.
318 TransGrid, *Revised revenue proposal*, p. 75.
319 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 3.
320 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 3.
321 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 20.
322 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 3.
323 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 21.

SAHA noted that the AER does not appear to question the validity of any of the risks presented.[324] Accordingly, SAHA suggested that if the AER maintains its position that the self insured quantifications for a number of the risks do not reasonably reflect the efficient costs associated with that risk, then the businesses should still be compensated in some way for bearing that risk, or alternatively, they must be allowed to adopt an alternative risk mitigation strategy.[325] SAHA stated that the AER should inform the businesses of the preferred method for mitigating these risks, or any adjustments that could be made to the proposed current quantification.[326]

Revised self insurance allowances

Based on SAHA's recommendations, TransGrid proposed that self insurance allowances be reinstated for the following events:[327]

- environmental contamination
- bomb threat/hoax, terrorism
- earthquakes
- bushfires
- damage to poles and lines
- third party claims associated with key asset failure
- contractual risk
- general public liability
- failure to supply.

TransGrid indicated that it had re–evaluated its self insurance requirements for environmental contamination. TransGrid stated that some costs associated with environmental contamination are likely to be subject to a time lag before being incurred by the business. TransGrid therefore applied a discount factor to the anticipated costs to reflect the effect of this time lag.[328]

TransGrid also recalculated its self insurance premium in relation to damage to underground cables (a component of the damage to poles and wires category). SAHA recalculated the self insurance premium based on damage to high voltage underground cables only, rather than both low and high voltage underground cables.[329] Further, in terms of key person risk, TransGrid indicated that it was prepared to manage its exposure to this risk within its overall opex allowance without seeking specific coverage under the self insurance allowance.[330]

The revised self insurance allowance proposed by TransGrid is set out in table 5.5.

[324] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 20.
[325] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 24.
[326] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 25.
[327] TransGrid, *Revised revenue proposal*, p. 74.
[328] TransGrid, *Revised revenue proposal*, p. 75.
[329] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 56.
[330] TransGrid, *Revised revenue proposal*, p. 75.

Table 5.5: TransGrid's revised self insurance allowance ($m, 2007–08)

	Draft decision	Revised revenue proposal
Total self insurance premium	6.8	11.0

Source: TransGrid, *Revised revenue proposal*, p. 76.

Submissions

Powerlink stated that the AER should not reject the principle of claiming for self insurance risks outright even if it is considered that the full extent of the proposed allowance is not justified. An assessment of the legitimacy of the risk should have resulted in some allowance being provided for under the regulatory framework, as opposed to no allowance at all.[331]

The EUAA was satisfied with the draft decision on the self insurance allowance for TransGrid.[332]

AER considerations

Details of the AER's assessment of TransGrid's revised proposed self insurance allowance are provided at appendix D.

The AER notes Powerlink's submission generally supports the comments made by TransGrid in its revised revenue proposal. The AER considers that its approach to the assessment of TransGrid's self insurance claims and the proposed alternative self insurance amount is consistent with the requirements of the NER.

Based on its assessment of the relevant opex factors in the NER, the AER considers it necessary to rely on the information provided in the revenue proposal (consistent with clause 6A.6.6(e)(1) of the NER) in determining whether the proposed self insurance allowances reasonably reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives. As such, where the information concerning an individual self insurance claim was assessed as inadequate—that is, it did not appear to support the claim—the AER has not accepted the forecast (consistent with clause 6A.6.6(d) of the NER).

Similarly, in determining a substitute self insurance value, the AER relied on the information included in the revenue proposal (as required by clauses 6A.14.1(3)(ii) and 6A.13.2 of the NER). For a number of risks, based on the information provided to the AER in the revenue proposal and revised revenue proposal, the only value that the AER could assign to an event was zero because there was no information on which to base an alternative amount. Such a value is not meant to indicate that the self insurance event may or may not occur, rather, the AER has assigned a cost of zero due to the (lack of) information provided in the revenue proposal.

The AER is satisfied that TransGrid's proposed reinstatement of an allowance for self insurance of environmental contamination risk reflects an efficient cost that a prudent

331 Powerlink, 16 February 2009, p. 3.
332 EUAA, p. 20.

operator in the circumstances of TransGrid would require to achieve the opex objectives.[333]

However, for other risks proposed for reinstatement by TransGrid the AER is not satisfied that TransGrid, based on advice from SAHA, has provided robust analysis which supports the probability of certain events occurring or that the costs of those events are reasonable. Accordingly it has not accepted the calculation of the self insurance premiums.

For the reasons discussed and as a result of the AER's analysis of the revenue proposal and revised revenue proposal, the AER is satisfied that the amended estimate of the total self insurance allowance for the next regulatory control period set out in table 5.6, based on the accepted self insurance premiums and substitute values detailed in appendix D, reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

Table 5.6: AER conclusion on self insurance allowance for TransGrid ($m, 2007−08)

	Revised revenue proposal	AER final decision
Total self insurance	11.0	9.2

5.6.4 Debt raising costs

Debt raising costs are incurred each time debt is rolled over, and may include underwriting fees, legal fees, company credit rating fees and other transaction costs. The AER has accepted that debt raising costs are a legitimate expense for which a TNSP should be provided an allowance.[334]

AER draft decision

In the draft decision, the AER did not accept TransGrid's proposal to include in its opex forecast a benchmark allowance for debt raising costs equal to 0.155 per cent (15.5 basis points) of the benchmark debt share (60 per cent) of the opening regulatory asset base (RAB) in each year of the next regulatory control period.[335]

The AER was not satisfied that there was a need to provide indirect debt raising costs under the regulatory framework, or that the AER's method for calculating the benchmark efficient costs under–compensated regulated network service providers (NSPs).[336]

Accordingly, the AER maintained its approach of providing benchmark debt raising costs in accordance with the 2004 Allen Consulting Group (ACG) methodology[337] as applied in previous transmission determinations.[338] This methodology involves the calculation of the

[333] The AER has also accepted some components of the allowance for other risks proposed for reinstatement (e.g. damage to poles and lines, and failure to supply).

[334] AER, *Decision Powerlink 2007–08 to 2011–12*, pp. 94–97; AER, *Final decision SP AusNet 2008–09 to 2013–14*, pp. 148–150; and AER, *Final decision ElectraNet 2008–09 to 2013–14*, pp. 84–85.

[335] AER, *Draft decision*, p. 139.

[336] AER, *Draft decision*, pp. 137–139.

[337] ACG, *Debt and equity raising transaction costs: final report to the ACCC*, December 2004.

[338] AER, *Decision Powerlink 2007–08 to 2011–12*, pp. 94–97; AER, *Final decision SP AusNet 2008–09 to 2013–14*, pp. 148–150; AER, *Final decision ElectraNet 2008–09 to 2013–14*, pp. 84–85.

cost of a benchmark bond issue size ($200 million), and the number of such bond issues required to rollover the benchmark debt share (60 per cent) of the RAB. The allowance for the benchmark bond issue is based on the direct costs of raising debt, such as underwriting fees, legal fees and credit rating fees.

Applying the ACG methodology to TransGrid, the AER approved an allowance of 8.1 basis points per annum (bppa) over the notional debt component of the RAB in each year, resulting in a total allowance of $11 million ($2007–08) over the next regulatory control period.[339]

Revised revenue proposal

TransGrid did not accept the draft decision on the basis that:

- the AER did not have sufficient regard to the evidence provided for indirect debt raising costs in its revenue proposal[340]
- the AER did not set out the basis and rationale for its draft decision, including the provision of details of the qualitative and quantitative methodologies it applied for the purposes of its draft decision, and the reasons for making it[341]
- the AER's use of private placements of debt as a proxy for estimating direct debt raising costs was fundamentally flawed and ignored the existence of more relevant data on public debt issuance[342]
- the AER approach to indirect (underpricing) costs of raising debt was flawed, ignoring a significant body of empirical evidence and failing to comprehend that direct and indirect costs are interdependent and neither can be set in isolation.[343]

In support of its revised revenue proposal, TransGrid restated arguments from the Competition Economists Group (CEG) report provided in its revenue proposal,[344] submitted a second CEG report[345] and commissioned further reports by Tony Carlton[346] and SFG Consulting.[347] In substance, these consultant reports are common to multiple revised revenue and regulatory proposals. Specifically, TransGrid, Transend, ActewAGL, Country Energy, EnergyAustralia and Integral Energy (NSW/ACT DNSPs) have all relied on essentially the same CEG report as the core of their arguments on this matter.[348]

On the basis of the recommendations of its consultants' reports, TransGrid proposed an allowance of 15.5 bppa based on the notional debt component of RAB for each year of the next regulatory control period. This resulted in a total proposed allowance of $22 million ($2007–08).

Table 5.7 sets out TransGrid's revised revenue proposal on debt raising costs.

339 AER, *Draft decision*, p. 139.
340 TransGrid, *Revised revenue proposal*, p. 76.
341 TransGrid, *Revised revenue proposal*, p. 77.
342 TransGrid, *Revised revenue proposal*, p. 77.
343 TransGrid, *Revised revenue proposal*, p. 78.
344 CEG, *Nominal Risk Free Rate, Debt Risk Premium and Debt and Equity Raising Costs,* Appendix to TransGrid revenue proposal, 31 May 2008 (CEG, May 2008).
345 CEG, *Debt and Equity Raising Costs*.
346 Carlton, T., *Indirect Costs of Equity and Debt Raising for TransGrid*, 12 January 2009.
347 SFGC, *Debt and equity issuance costs for a benchmark transmission business: Report prepared for TransGrid*, 20 March 2009.
348 CEG, January 2009.

Table 5.7: TransGrid's revised revenue proposal on debt raising costs ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's revised revenue proposal	3.7	4.0	4.3	4.7	5.0	21.7

Source: TransGrid, *Revised revenue proposal*, p. 78.

Submissions

EnergyAustralia noted that all the NSPs proposed the same allowance for debt raising costs (15.5 bppa on the debt component of RAB) and that this was the same position stated in their respective regulatory proposals.[349] Given the evident consistency across proposals, EnergyAustralia requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and revised regulatory proposal be considered by the AER in making its final determination for TransGrid for the next regulatory control period.

Powerlink submitted that the AER should reconsider its position on the acceptance of direct and indirect debt raising costs for TransGrid in light of the compelling evidence presented by CEG.[350]

EnergyAustralia's further submission on the draft decision attached the Joint Industry Association's (JIA) submission to the AER's WACC review.[351] The JIA stated that indirect and direct debt raising costs were direct substitutes (in line with the CEG report), and that the AER needed to adjust its previous methodology upwards (to at least 19.5 bppa) to provide an allowance for indirect costs.[352] Additionally, JIA questioned the appropriateness of the direct cost proxy used in the ACG methodology and argued that each NSP should specify the timing and size of each debt issue in their regulatory proposal rather than accepting allowances based on average AER assessments.[353]

Consultant review

The AER engaged Dr John C. Handley, Associate Professor in Finance at the University of Melbourne, to review the submitted material on this issue, including the revenue proposal and revised revenue proposal submitted by TransGrid, and all relevant accompanying consultant reports.[354]

In his report, Associate Professor Handley segregated debt raising costs into two key areas: indirect (underpricing) and direct. On the underpricing of debt capital, he stated:

349 EnergyAustralia, *Submission on other network service providers*, p. 3.
350 Powerlink, 16 February 2009.
351 EnergyAustralia, *Submission, attachment V: Joint Industry Association (JIA), Network Industry Submission: Debt and Equity Raising Costs*, 11 November 2008.
352 JIA, pp. 20–21.
353 JIA, p. 21.
354 Handley, J. C. *A Note on the Costs of Raising Debt and Equity Capital: Report prepared for the Australian Energy Regulator*, 12 April 2009. Associate Professor Handley is a leading academic on cost of capital issues and has been advising the AER as part of its 2009 WACC review.

> The key issue is whether the AER's approach to estimating the cost of debt for the regulated firm is appropriate. If it is then, by definition, no compensation for underpricing is necessary, otherwise double counting would arise.[355]

Associate Professor Handley then reviewed the methodology adopted by the AER, noted CEG's review of this methodology and specifically considered the Cai, Helwege and Warga (2007) paper that found no evidence of underpricing on investment grade bond offerings. He concluded:

> In summary, assuming allowed revenues are determined using an appropriate estimate of the cost of debt (and noting that both the AER and CEG believe this to be the case), then it is my view that, underpricing should not be allowed as a cost of raising debt capital.[356]

On the direct costs of raising debt capital, Associate Professor Handley noted the debate regarding the measurement of direct costs, amortisation and inflation. Where relevant, detailed comments drawn from his review are included in the AER considerations, set out in appendix E of this final decision.

AER considerations

The AER's detailed considerations of TransGrid's proposed debt raising costs are presented in appendix E of this final decision. The AER notes that the consultancy reports submitted by TransGrid on these matters are also applicable to the AER's considerations concerning Transend's revenue proposal and the regulatory proposals of ActewAGL and the NSW DNSPs. The AER considers that its approach should be consistently applied across each of these businesses. Accordingly, appendix E sets out the AER consideration of all material submitted as part of the current regulatory processes and is applicable to the AER's final decisions for TransGrid, Transend, ActewAGL and the NSW DNSPs.

In summary, the AER considers that the proposed allowance for indirect debt raising costs is inconsistent with the regulatory framework. If indirect costs were actually incurred in practice,[357] the AER expects that such costs would already be taken into account through estimates of the cost of debt. This view is supported by Associate Professor Handley.[358]

Regarding the appropriate benchmark for direct debt raising costs, the AER considers that the amount applied in the draft decision—based on the ACG approach—is appropriate.[359] The AER considers that the ACG approach is more likely to provide a better estimate of direct debt raising costs to be incurred by the benchmark regulated business than the methodologies proposed by the NSPs and their consultants. Among other reasons, this is largely because the ACG approach is based on market observations of Australian firms raising capital, rather than foreign firms in foreign markets.

Table 5.8 shows the updated build up of debt raising costs and the total benchmark for various bond issues, based on the ACG's methodology.

355 Handley, p. 15–16.
356 Handley, p. 17.
357 The AER considers that there is no reliable empirical evidence that indirect debt raising costs exist.
358 Handley, pp.14–17.
359 AER, *Draft decision*, p. 139.

Table 5.8: Benchmark debt raising costs for corporate bond issues (bppa)

Fee	Explanation/source	1 issue	2 issues	6 issues	13 issues
Amount raised	Multiples of median bond issue size	$200m	$400m	$1200m	$2600m
Gross underwriting fees	Bloomberg for Australian internal issues, term adjusted	6.0	6.0	6.0	6.0
Legal and roadshow	$75k–$100k: industry sources	1.0	1.0	1.0	1.0
Company credit rating	$30k–$50k (once off): Standard & Poor's ratings	2.5	1.3	0.4	0.2
Issue credit rating	3.5 (2.5) basis points up front: Standard & Poor's ratings	0.7	0.7	0.7	0.7
Registry fees	$3k/issue: Osborne Associates	0.2	0.2	0.2	0.2
Paying fees[a]	$1/$1m quarterly: Osborne Associates	0.0	0.0	0.0	0.0
Total	Basis points per annum	10.4	9.2	8.3	8.1

Source: AER updated figures based on the methodology in ACG, Debt and equity raising transaction costs: final report to the ACCC, December 2004.

(a) Rounded to zero.

The AER maintains its gross underwriting fee and bond issue size benchmarks which were set out in the draft decision, and which were updated according to the ACG methodology.[360] Based on the ACG methodology, TransGrid will require around 13 bond issues over the next regulatory control period. As such, the AER considers that an allowance of 8.1 bppa for debt raising costs is a reasonable benchmark for TransGrid. Using the post–tax revenue model (PTRM), this benchmark is multiplied by the debt component of TransGrid's opening RAB to provide an average allowance of $2.2 million per annum ($2007–08).

The AER's conclusion on benchmark debt raising costs for TransGrid over the next regulatory control period is set out in table 5.9.

Table 5.9: AER conclusion on benchmark debt raising costs ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Debt raising allowance	1.9	2.1	2.2	2.4	2.6	11.2

For the reasons discussed and as a result of the AER's analysis of TransGrid's revised revenue proposal and additional information, the AER is not satisfied that TransGrid's proposed debt raising cost allowance reasonably reflects the opex criteria, including the

[360] AER, *Draft decision*, p. 139.

opex objectives. In coming to this view, the AER has had regard to the opex factors. The AER considers the benchmark debt raising allowance set out in table 5.9 represents the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives in the next regulatory control period.

5.6.5 Equity raising costs

In raising new equity capital a business may incur costs such as legal fees, brokerage fees, marketing costs and other transaction costs. These are upfront expenses, with little or no ongoing costs over the life of the equity. Whilst the size of the equity a firm will raise is typically at its inception, there may be points in the life of a firm—for example, during capital expansions—where it chooses additional external equity funding (instead of debt or internal funding) as a source of equity capital, and accordingly may incur equity raising costs.

The AER has accepted that equity raising costs are a legitimate cost for a benchmark efficient firm only where external equity funding is the least–cost option available.[361] A TNSP should only be provided an allowance for equity raising costs where cheaper sources of funding—for instance, retained earnings—are insufficient, subject to the gearing ratio and other assumptions about financing decisions being consistent with regulatory benchmarks.

AER draft decision

In the draft decision, the AER did not accept TransGrid's proposal for an opex allowance for equity raising costs equal to 7.6 per cent of the required equity, (based on the capex allowance) at a total cost of $14 million ($2007–08) over the next regulatory control period.[362]

The AER rejected both of the central arguments set out in TransGrid's revenue proposal regarding equity raising costs. First, the AER was not satisfied that there was a need to take account of the indirect costs of raising equity under the benchmark regulatory framework.[363] Citing a report by CEG, TransGrid argued that the indirect and direct costs of raising equity were linked (in a similar way to debt raising costs) and that the underpricing of equity was required to ensure the success of a capital raising. The AER was not convinced by these arguments, and applied the ACG (2004) methodology for calculation of direct equity raising costs only.[364]

Second, the AER was not satisfied that there was a need for TransGrid to raise external equity.[365] TransGrid contended that, as part of the benchmark cash flow analysis to determine an external equity requirement, a dividend yield of 8.6 per cent should be applied, and based on its analysis, TransGrid submitted that it would need to raise new equity.[366] By contrast, in reviewing TransGrid's revenue proposal the AER undertook a benchmark cash flow analysis, and adopted a 70 per cent dividend payout ratio instead of

---

361 AER, *Decision Powerlink 2007–08 to 2011–12*, pp. 100; AER, *Final decision SP AusNet 2008–09 to 2013–14*, p. 144; AER, *Final decision ElectraNet 2008–09 to 2013–14*, p. 88.
362 AER, *Draft decision*, p. 145.
363 AER, *Draft decision*, p. 141.
364 AER, *Draft decision*, p. 142.
365 AER, *Draft decision*, pp. 142–145.
366 TransGrid, *Revenue proposal*, May 2008, pp. 91–92.

a dividend yield.[367] The AER's analysis indicated that TransGrid would be able to fund its capex program over the next regulatory control period with retained cash flows. Accordingly, the AER determined that TransGrid would not require additional equity finance in the next regulatory control period and therefore would also not require an allowance for equity raising costs.[368]

Revised revenue proposal

TransGrid did not accept the draft decision and argued on a number of grounds for the acceptance of its revenue proposal. In general, TransGrid claimed that the AER had not considered or had not given sufficient regard to the evidence put forward by TransGrid in relation to equity raising costs.[369] Many of the issues and arguments raised by TransGrid were based on a CEG report commissioned in conjunction with Transend, and the ACT and NSW DNSPs.[370]

TransGrid stated that the AER provided no theoretical or empirical basis for two of its key assumptions:[371]

1. The efficient benchmark firm should be able to raise new capital with a rights issue without requiring compensation for any underpricing.
2. The allowed WACC is sufficient to induce new investment such that further compensation is unnecessary and inconsistent with the assumptions of the benchmark regulatory framework.

TransGrid asserted that the AER was incorrect to apply a 'stylised' capital asset pricing model (CAPM) assumption (that all investors have homogenous expectations) to a real–world issue such as the existence of underpricing.[372]

TransGrid stated that the AER had incorrectly suggested that underwriting fees could be adjusted by the fair value of the option component, without considering both put and call options.[373] TransGrid also stated that the AER did not deal adequately with the empirical evidence on average underpricing.[374]

TransGrid argued that the 'discounted rights issue' proposed by the AER was an inappropriate model from which to conclude that a benchmark seasoned equity offering (SEO) would be free of indirect costs.[375]

TransGrid stated that there were two methodological flaws in the AER's benchmark cash flow analysis:

- the analysis did not ensure the business pay back any principal on its debt, which breached the regulatory gearing assumption (60 per cent debt ratio)[376]

367 AER, *Draft decision*, p. 145.
368 AER, *Draft decision*, p. 146.
369 TransGrid, *Revised revenue proposal*, p. 79.
370 CEG, January 2009.
371 TransGrid, *Revised revenue proposal*, p. 79.
372 TransGrid, *Revised revenue proposal*, p. 80.
373 TransGrid, *Revised revenue proposal*, p. 80.
374 TransGrid, *Revised revenue proposal*, p. 79.
375 TransGrid, *Revised revenue proposal*, p. 80.
376 TransGrid, *Revised revenue proposal*, pp. 80–81

- the full value of imputation credits was included as part of the return on equity to shareholders, but the assumed payout of dividends was insufficient to distribute all these credits.[377]

TransGrid argued that the AER assertion that a dividend yield of 8.6 per cent was unsustainable was incorrect, since this yield was less than the return on equity and therefore sustainable in the long run.[378] TransGrid rejected the 70 per cent dividend payout ratio assumed by the AER, on the grounds that the dividend yield which resulted was below the expectations of equity holders. Notwithstanding the criticisms made by TransGrid, it applied the AER's proposed dividend payout ratio in its benchmark cash flow analysis submitted with its revised revenue proposal.[379]

TransGrid also claimed that reinvestment of retained earnings was not costless.[380]

In support of its revised revenue proposal, TransGrid restated arguments from the original CEG report,[381] submitted a second CEG report[382] and commissioned further consultant reports from Professor Bruce Grundy,[383] Tony Carlton[384] and SFG Consulting.[385] As with debt raising costs, most of these consultant reports were submitted by multiple NSPs with their revised regulatory proposals.

On the basis of the recommendations of its consultants, TransGrid proposed an allowance of 7.6 per cent applied to the additional equity requirement of $181 million (nominal) over the next regulatory control period. This resulted in a total proposed allowance of $14 million ($2007–08) over the next regulatory control period.[386] Table 5.10 provides TransGrid's revised revenue proposal on equity raising costs.

Table 5.10: TransGrid's revised revenue proposal on equity raising costs ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's revised revenue proposal[a]	1.1	1.9	3.0	3.8	3.8	13.6

Source: TransGrid, *Revised revenue proposal,* p. 82.
(a) The AER notes that this proposed equity raising cost allowance does not include an estimate of retained earnings. TransGrid's cash flow modelling provided with its PTRM calculated total equity raising costs of $38 million ($2007–08).

377 TransGrid, *Revised revenue proposal*, p. 81.
378 TransGrid, *Revised revenue proposal*, p. 81.
379 TransGrid, *Revised revenue proposal*, pp. 81–82.
380 TransGrid, *Revised revenue proposal*, p. 81.
381 CEG, May 2008.
382 CEG, January 2009.
383 Grundy, B. D., *A Note on the Costs of Equity Financing*, 13 January 2009.
384 Carlton, T., *Indirect Costs of Equity and Debt Raising for TransGrid*, 12 January 2009.
385 SFGC, *Debt and equity issuance costs for a benchmark transmission business; Report prepared for TransGrid*, March 2009.
386 The AER notes that this proposed equity raising cost allowance does not include an estimate of retained earnings. TransGrid's cash flow modelling provided with its PTRM calculated total equity raising costs of $38 million ($2007–08). TransGrid, *Revised revenue proposal*, p. 82.

Submissions

EnergyAustralia noted that all the NSPs were proposing the same allowance for equity raising costs (7.6 per cent of the amount raised) and that this was the same position as advocated in their respective regulatory proposals. Given the evident consistency across proposals, EnergyAustralia requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and revised regulatory proposal be considered by the AER in making its final determination for TransGrid for the next regulatory control period.[387]

Powerlink questioned whether the AER had given due and appropriate consideration to the evidence from CEG regarding the equity raising allowance for TransGrid. Powerlink noted that the AER accepted the possible existence of underpricing for SEOs, yet did not allow compensation for this indirect cost. Powerlink did not consider that the AER had demonstrated theoretically or empirically why compensation for indirect costs would be inconsistent with the benchmark WACC framework, or why efficient benchmark NSPs should be able to raise capital without incurring underpricing costs.[388]

EnergyAustralia's further submission on the draft decision attached the JIA submission to the AER's WACC review.[389] The JIA stated that indirect and direct equity raising costs were direct substitutes (in line with the CEG report), and that the AER needed to adjust its previous methodology to provide an allowance for indirect equity raising costs.[390] JIA stated that using internal cash flows to fund new capex is not costless, and that infrastructure businesses must satisfy their investors by providing a high dividend yield (8 per cent) each year.[391]

Consultant review

Associate Professor Handley was engaged by the AER to review the submitted material on this issue, including the revenue proposal and revised revenue proposal submitted by TransGrid, and all relevant accompanying consultant reports.

Associate Professor Handley considered the arguments made on the underpricing of equity capital, and noted that both CEG and Carlton relied upon the assumption that new shares were not sold to existing shareholders.[392] Associate Professor Handley viewed this assumption as unreasonable. He also considered it inappropriate to provide an allowance for underpricing costs associated with raising equity capital as they are inconsistent with the regulatory framework:[393]

> …under the regulatory framework the appropriate return on (equity) capital is determined by the CAPM and therefore any allowance for underpricing costs would effectively amount to an increment being added to the CAPM – a position which could only be justified on policy rather than theoretical grounds.

387 EnergyAustralia, *Submission on other network service providers*, p. 3.
388 Powerlink, 16 February 2009, pp. 2–3.
389 JIA.
390 JIA, p. 17.
391 JIA, pp. 11–17.
392 Handley, pp. 7–8..
393 Handley, p. 11.

Associate Professor Handley considered the indirect costs of retained earnings, rights issues and dividend reinvestment plans, and concluded in each case that it was not appropriate to provide an allowance for such costs.[394]

Associate Professor Handley also considered the direct costs of raising equity capital, noting the different methods (placements, rights issues and dividend reinvestment plans) and the level of agreement on these direct costs. He advised that the reasonable range for direct equity raising costs is between 2 and 3 per cent of the amount raised.[395]

Finally, Associate Professor Handley considered the benchmark cash flow modelling applied to determine the equity requirement. He noted many of the assumptions were 'arbitrary in the sense that they are simply inputs into the modelling process,'[396] but stated:[397]

> The key issue is to ensure that any assumptions made here are consistent with the overall regulatory framework.

Associate Professor Handley analysed the concerns raised in relation to payment of debt principal for maintaining the assumed gearing ratio, and the payout of dividends in order to value imputation credits. In both cases, Associate Professor Handley noted that the NSPs' concerns were valid and that the AER should amend its benchmark cash flow analysis to take account of these concerns.[398]

AER considerations

The AER's detailed considerations of TransGrid's proposed equity raising costs are presented in appendix E of this final decision. The AER notes that the consultancy reports submitted by TransGrid on these matters are also applicable to the AER's considerations concerning Transend's revenue proposal and the regulatory proposals of ActewAGL and the NSW DNSPs. The AER considers that its approach should be consistently applied across each of these businesses. Accordingly, appendix E sets out the AER consideration of all material submitted as part of the current regulatory processes and is applicable to the AER's final decisions for TransGrid, Transend, and the ACT/NSW DNSPs.

In summary, the AER considers that the proposed allowance for indirect equity raising costs is inconsistent with the regulatory framework. To the extent that indirect equity raising costs exist, they can reasonably be expected to be included in the existing return on equity allowance which is based on the expected market returns through the CAPM parameters. Alternatively, they are not relevant to the benchmark firm as they relate to the impact on individual shareholders rather than the returns in aggregate (at the firm level). This view is supported by Associate Professor Handley.[399]

In relation to direct equity raising costs, the AER considers that the benchmark cost applied in the draft decision remains the best estimate of costs applicable to the benchmark regulated NSP. The benchmark direct equity raising cost applied in the draft decision for the NSW DNSPs was based on the ACG methodology, which used recent

394 Handley, pp. 4–14.
395 Handley, p. 27.
396 Handley, p. 31–32.
397 Handley, p. 32.
398 Handley, pp. 31–34.
399 Handley, p. 11.

domestic market data.[400] The AER also notes that this benchmark equity raising cost is within the range recommended by Associate Professor Handley.[401]

The AER has given consideration to the consultant reports and submissions concerning the benchmark cash flow analysis that is applied to determine the extent to which equity raising is required. Among other issues with the benchmark cash flow analysis, TransGrid submitted that the draft decision understated the appropriate level of dividends.[402] This resulted in a higher level of retained earnings, which inturn, resulted in a lower external equity requirement. CEG stated that, by lowering dividends, a firm's ability to distribute imputation credits is reduced.[403] CEG also argued for an allowance for the cost of retained earnings.[404] The AER has decided to amend the benchmark cash flow analysis to ensure consistency with the cash flow assumptions in the PTRM. However, it has also taken the level of equity raising through dividend reinvestment plans into account. Further, the AER has decided that it would be inappropriate to include an allowance for the cost of retained earnings.

In summary, the changes to the equity raising benchmark cash flow analysis (from the approach applied in the draft decision) include:

- dividends are linked to the level of imputation credits earned in the PTRM (rather than applying a dividend payout ratio to net profit after tax)
- dividend reinvestment is assumed to be 30 per cent of dividends paid (based on available evidence)
- a benchmark cost of 1 per cent has been applied to equity raised through dividend reinvestment plan
- an error in the presentation of the capex funding requirement has been corrected (in the draft decision the capex funding requirement inappropriately included a 'grossed–up' WACC adjustment)
- the amount of capex assumed to be funded by debt has been linked to the increase in the debt component of the RAB to maintain consistency with the benchmark gearing assumption in the PTRM.

The AER's conclusion on benchmark equity raising costs for TransGrid over the next regulatory control period is set out in table 5.11.

400 AER, *Draft decision*, pp. 142–145.
401 Handley, p. 27.
402 TransGrid, *Revised revenue proposal*, p. 81.
403 TransGrid, *Revised revenue proposal*, Appendix N, p. 29.
404 TransGrid, *Revised revenue proposal*, Appendix N, pp. 29–30.

Table 5.11: AER conclusion on TransGrid's benchmark equity raising cost ($m, nominal)

Cash flow analysis	AER final decision (total)	Notes
Dividends	342.5	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	102.8	30% of dividends paid
Cost of dividend reinvestment plans	1.0	Dividends reinvested multiplied by benchmark cost (1%)
Capex funding requirement	2580.8	This is the forecast capex funding requirement (not the capex value that includes a half year WACC adjustment)
Debt component	1388.7	Set to equal 60% of RAB increase (not capex)
Equity component	1192.1	Residual of capex funding requirement and debt component
Retained cash flows available for reinvestment	1110.4	Includes dividends reinvested
External equity requirement	81.7	Equal to equity component less retained cash flows
External equity raising cost	2.2	External equity requirement multiplied by benchmark direct cost (2.75%)
Total equity raising cost	3.3	Sum of dividend reinvestment plan cost and external equity raising cost
Total equity raising cost ($2008–09)	3.1	To be added to the RAB at the start of the next regulatory control period

TransGrid proposed including equity raising costs as part of its forecast opex allowance.[405] The AER considers that there is merit in treating the equity raising cost allowance as a part of TransGrid's RAB—that is, to amortise the allowance. This would improve transparency, given that the nature of the allowance is associated with capex, and ensure that future revenue resets for TransGrid would be administratively simpler in the provision of such an allowance.

Further, the AER notes that treating the equity raising cost allowance in perpetuity or in the RAB would be net present value (NPV) neutral. In the 2004 ACG report, it was

405 TransGrid, *Revised revenue proposal*, pp. 82–83.

recommended that equity raising costs be added to the RAB and amortised along with other assets:[406]

> If the regulator has determined that an allowance for the SEO [seasoned equity offering] cost of raising equity for ongoing capital expenditure should be provided for, we recommend that this amount be added to the RAV [regulatory asset value] (i.e. included as part of the capital expenditure cost) and depreciated over the life of the relevant assets.

Accordingly, the amount specified in table 5.11 will be amortised over the life of TransGrid's RAB for the purposes of providing the equity raising cost allowance associated with the forecast capex over the next regulatory control period.[407] This approach is also consistent with the AER's revenue determination for Powerlink.[408]

For the reasons discussed and as a result of the AER's analysis of TransGrid's revised revenue proposal and additional information, the AER is not satisfied that TransGrid's proposed equity raising cost allowance reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors. The AER considers the revised benchmark equity raising cost allowance associated with TransGrid's forecast capex, as set out in table 5.11 represents the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives in the next regulatory control period.

5.6.6 Other Issues

AER considerations

Demand management allowance

The EUAA noted the AER's draft decision to include an allowance of $1 million per annum for TransGrid to develop and investigate demand management solutions to network constraints, building upon the outcomes of the DMPP.[409] The EUAA recommended that the AER investigate the outcomes of the DMPP, given that no savings associated with demand management initiatives were identified within TransGrid's revenue proposal.[410]

In reviewing TransGrid's revised revenue proposal, the AER requested that TransGrid identify any capex projects that were deferred as a result of the DMPP.[411] TransGrid responded by outlining a current network support project to allow deferral of its proposed 500 kV Western Upgrade Project, in which outcomes and learnings of the DMPP have been applied to gain an expected cost saving of approximately $20 million. This saving will be passed onto consumers through lower transmission use of system charges.

In addition, TransGrid identified a potential project deferral it is working with EnergyAustralia to implement, in the Sydney CBD and Inner Metropolitan areas, to

406 ACG, p. xiii.

407 A standard life of 40.6 years for amortisation purposes, consistent with TransGrid's weighted average asset life, has been assumed.

408 AER, *Decision Powerlink 2007–08 to 2011–12*, p. 102.

409 NSW Department of Planning, *Demand Management and Planning Project, Project Background*, http://www.planning.nsw.gov.au/dmpp/reports.asp.

410 EUAA, p. 4.

411 AER, Email request to TransGrid, 27 February 2009.

ensure secure supply reliability for customers. TransGrid also noted that the DMPP resulted in the successful installation of standby generation and cogeneration with two major commercial customers in Sydney, which could be replicated in other regions of its network.[412]

Overall, the AER is satisfied that the DMPP has resulted in outcomes that will enable TransGrid to further investigate and apply demand management solutions to network constraints, benefiting consumers by lowering the costs of network augmentation. Accordingly, the AER maintains its draft decision to provide TransGrid with an annual allowance of $1 million to further investigate innovative demand management solutions, and apply and build upon the outcomes of the DMPP.

Cost allocation of accommodation and human resources

The EUAA submitted that the AER should examine how overheads, like the costs of accommodation and human resources, have been allocated to parts of the business so that electricity customers are not cross–subsidising other areas of TransGrid's activities.[413]

The AER notes that TransGrid was required to prepare and submit a Cost Allocation Methodology (CAM) to the AER before 28 March 2008 in accordance with clause 6A.19.4(a)(1) of the NER. The TransGrid CAM was approved by the AER. Further, TransGrid confirmed with the AER that all operational costs are allocated appropriately and in accordance with TransGrid's CAM, as demonstrated to and confirmed by TransGrid's independent auditor. PB advised the AER that it did not discover any reason to indicate that TransGrid is not allocating costs in accordance with the CAM. Based on the above, the AER is satisfied that TransGrid's allocation of costs is appropriate.

Network support

The EUAA raised concerns surrounding the pass through provisions relating to network support events. The EUAA stated that the TNSP has no incentive to draw any underspend of the allowance to the attention of the AER and, therefore, proposed that the AER mandate the provision of information to promote transparency.[414]

A network support pass through is an adjustment made for network support events arising from an over or under spend in network support payments that were provided for in a transmission determination. The network support pass through provisions are set out at clause 6A.7.2 of the NER.

As stated in the draft decision, if a positive (defined as an overspent amount) or negative (defined as an underspent amount) network support event occurs during a regulatory control period, a TNSP must seek a determination by the AER for a network support pass through amount to customers.[415] Regardless of whether the AER is notified by a TNSP, the AER may make a determination to pass through any underspent amount to consumers.[416] Further, the AER expects TransGrid to notify it of any underspent amounts relating to its network support allowance, to ensure that these amounts are passed back to customers.

412 TransGrid, Response to issue 327, 6 March 2009.
413 EUAA, p. 5.
414 EUAA, p. 4.
415 AER, *Draft decision*, p. 133.
416 NER, clause 6A.7.2(f).

5.7 AER conclusion

The AER has considered TransGrid's revised forecast total opex proposal of $810 million ($2007–08) and for the reasons outlined in this chapter, the AER is not satisfied that this total opex forecast proposed by TransGrid reasonably reflects the opex criteria under clause 6A.6.6(c) of the NER, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

As the AER is not satisfied that TransGrid's total forecast opex reasonably reflects the opex criteria, under clause 6A.6.6(d), the AER must not accept the forecast opex in TransGrid's revised revenue proposal. Therefore, the AER is required under clause 6A.14.1(3)(ii) of the NER to provide an estimate of the total opex that TransGrid will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

After undertaking its own analysis of TransGrid's proposed total opex and based on the advice of PB, the AER has applied a reduction of $52 million to TransGrid's revised opex proposal. This represents a reduction of around 6.4 per cent of TransGrid's revised forecast opex proposal and results in an amended forecast opex allowance of $758 million for the next regulatory control period.[417]

This amended allowance represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c) of the NER. The AER is satisfied that the amended total forecast opex allowance of $758 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. The revised opex allowance is set out by opex category in table 5.12.

In addition, the AER will allow TransGrid to amortise a total of $3.1 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.

[417] The forecast opex allowance is $786 million in 2008–09 dollar terms.

Table 5.12: AER conclusion on TransGrid's forecast opex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's revised proposed controllable opex	128.5	138.4	142.7	152.5	155.7	717.8
Debt raising costs	3.7	4.0	4.3	4.7	5.0	21.7
Equity raising costs[a]	1.1	1.9	3.0	3.8	3.8	13.6
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance	2.2	2.2	2.2	2.2	2.2	11.0
TransGrid's total opex	157.1	152.5	158.2	169.1	172.7	809.6
AER controllable opex	127.6	135.0	138.1	145.4	145.7	691.7
Debt raising costs	1.9	2.1	2.2	2.4	2.6	11.2
Equity raising costs[b]	–	–	–	–	–	–
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance	1.8	1.8	1.8	1.8	1.8	9.2
AER total opex allowance	152.9	144.9	148.2	155.6	156.1	757.6

Note: Totals may not add up due to rounding.

(a) The proposed equity raising cost allowance does not include an estimate for retained earnings. TransGrid's cash flow modelling provided with its revised revenue proposal PTRM calculated total equity raising costs of $38 million ($2007–08).

(b) The AER will allow TransGrid to amortise a total of $3.1 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.

Table 5.13 sets out the AER's adjustments to TransGrid's forecast controllable opex allowance. These adjustments were derived by TransGrid from its opex model and reflect the AER's conclusion on an efficient controllable opex allowance.

Table 5.13: AER conclusion on TransGrid's controllable opex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER controllable opex allowance (draft decision)	128.4	135.7	139.5	147.9	149.9	701.3
TransGrid's revised proposed controllable opex	128.5	138.4	142.7	152.5	155.7	717.8
Adjustment for labour escalators	–1.2	–1.1	–1.8	–3.1	–4.9	–12.2
Adjustment for revised capex forecast[a]	–	–	–	–	–	–0.1
Adjustment for defect maintenance	0.3	–2.3	–2.8	–3.9	–5.1	–13.8
AER adjusted controllable opex	127.6	135.0	138.1	145.4	145.7	691.7

Note: Totals may not add up due to rounding.

(a) Rounded to zero. Updates arising from the AER amendments to the capex allowance set out in chapter 3.

6 Efficiency benefit sharing

6.1 Introduction

This chapter sets out the AER's assessment of efficiency savings accruing to TransGrid under the efficiency carry forward mechanism (ECFM), which applies to its opex allowance in the current regulatory control period. It also sets out how the efficiency benefit sharing scheme (EBSS) is to apply to TransGrid for the next regulatory control period, and takes into account issues raised in response to the draft decision.

The ECFM provides TNSPs with more consistent efficiency incentives by allowing them to retain the benefit of any savings (or exposing them to the detriment of any losses) for the same length of time regardless of when in the regulatory control period the gains/losses are made. During the next regulatory control period TransGrid will receive benefits/penalties for efficiency gains/losses made during the current regulatory control period in accordance with the ECFM.

The EBSS has evolved from the ECFM and operates in a similar manner. The AER published the EBSS under clause 6A.6.5(a) of the NER, which establishes that an EBSS will apply to TransGrid from 1 July 2009.[418] The scheme will not have a direct financial impact on TransGrid until the 2014–19 regulatory control period, when TransGrid will receive carryover benefits/penalties for efficiency gains/losses made during the next regulatory control period.

There were no submissions received on this issue.

6.2 AER draft decision

The AER determined a total opex efficiency allowance under the ECFM of $8.9 million ($2008–09) for TransGrid over the next regulatory control period.[419]

The AER decided it would apply the EBSS to TransGrid for the next regulatory control period.[420] The EBSS shares between TNSPs and transmission network users the efficiency gains or losses derived from the difference between a TNSP's actual opex and the forecast opex for a regulatory control period.

In the event actual demand growth was outside the range of scenarios modelled in the development of TransGrid's approved forecast capex, for the purposes of the EBSS, forecast opex will be adjusted based on the models (opex and capex) used to develop TransGrid's approved forecast opex.[421] The EBSS would therefore incorporate the impact on opex of actual demand growth on the commissioning of new assets.

The AER also decided that the following opex cost categories would be excluded from the operation of the EBSS for the next regulatory control period:[422]

418 AER, *Electricity transmission network service providers–Efficiency benefit sharing scheme*, September 2007.
419 AER, *Draft decision*, p. 152.
420 AER, *Draft decision*, p. 156.
421 AER, *Draft decision*, p. 156.
422 AER, *Draft decision*, p. 156.

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives.

These categories would be in addition to the costs associated with any pass through events that are directly excluded by the EBSS.

6.3 Revised revenue proposal

TransGrid stated that it has implemented all aspects of the draft decision with the exception of the ex post demand growth adjustment method.[423]

TransGrid stated that the high and low growth scenarios cited by the AER in the draft decision were not those used by TransGrid in forecasting its capex program. TransGrid stated that the New South Wales summer 10 per cent probability of exceedence (PoE) and winter 90 per cent PoE native maximum demand projections would more accurately reflect the load growth scenarios used in forecasting its capex allowance for the next regulatory control period.[424]

6.4 Issues and AER considerations

6.4.1 Efficiency carry forward mechanism carryover amounts

AER draft decision

In the draft decision, the AER calculated the efficiency gains/losses outlined in table 6.1, which it used to calculate the ECFM allowance in table 6.2.

Table 6.1: AER draft decision efficiency gains/losses under the ECFM ($m, 2008–09)

	2004–05	2005–06	2006–07	2007–08	2008–09
Forecast target opex	135.3	134.8	134.4	134.0	133.8
Actual opex	134.1	134.5	130.9	125.6	129.4[a]
Efficiency gain/loss	1.2	–0.9	3.2	4.9	–3.9

Source: AER, *Draft decision*, p. 152.
(a) Actual opex is assumed to equal TransGrid's forecast at the time it made its revenue proposal.

423 TransGrid, *Revised revenue proposal*, p. 86.
424 TransGrid, *Revised revenue proposal*, p. 87.

Table 6.2: AER draft decision opex efficiency allowance under the ECFM ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Opex efficiency allowance	4.5	3.2	4.1	1.0	–3.9	8.9

Source: AER, *Draft decision*, p. 152.

The efficiency gains/losses in table 6.1 were calculated using forecast inflation for 2008–09. The AER noted in the draft decision that it would update the calculation of efficiency gains/losses with the actual inflation for 2008−09 at the time of its final decision.[425]

Revised revenue proposal

TransGrid did not explicitly discuss the ECFM efficiency gains/losses for the current regulatory control period, nor the resultant efficiency carryover allowance for the next regulatory control period. However, TransGrid stated that it had implemented all aspects of the AER's draft decision with the exception of the ex post demand growth adjustment method.[426] TransGrid also updated its forecast of opex for 2008–09.

AER considerations

The AER has updated the efficiency gains/losses for TransGrid under the ECFM using actual inflation for 2008–09 (March to March) and TransGrid's updated forecast of opex for 2008–09. These are outlined in table 6.3.

Table 6.3: Updated efficiency gains/losses under the ECFM ($m, 2008–09)

	2004–05	2005–06	2006–07	2007–08	2008–09
Forecast target opex	134.9	134.4	133.9	133.6	133.4
Actual opex	133.6	134.0	130.5	125.2	127.7[a]
Efficiency gain/loss	1.2	–0.9	3.1	4.9	–2.7

(a) Actual opex is assumed to equal TransGrid's forecast at the time it made its revised revenue proposal.

Using the revised efficiency gain/loss figures outlined in table 6.3, the AER calculated the final opex efficiency allowances under the ECFM in table 6.4.

Table 6.4: Updated opex efficiency allowance under the ECFM ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Opex efficiency allowance	5.7	4.5	5.4	2.2	–2.7	15.1

425 AER, *Draft decision*, p. 152.
426 TransGrid, *Revised revenue proposal*, p. 86.

6.4.2 EBSS demand growth adjustment

AER draft decision

In the draft decision, the AER considered TransGrid's proposal that a growth adjustment would only be applied if actual demand was outside the range of reasonable growth scenarios modelled in developing its revenue proposal.[427] The AER considered that where actual demand was outside the range used, the actual level of demand would be used to recalculate forecast opex requirements, using the modelling process applied for this determination.[428] The AER cited the low and high growth scenarios with a 50 per cent PoE from TransGrid's *NSW annual planning report 2008*, as the demand range to use for this purpose.[429]

Revised revenue proposal

TransGrid stated that the high and low growth scenarios cited by the AER in the draft decision were not those used by TransGrid in forecasting its capex program.[430] TransGrid stated that the New South Wales summer 10 per cent PoE and winter 90 per cent PoE native maximum demand projections would more accurately reflect the load growth scenarios used in forecasting its capex allowance for the next regulatory control period. Consequently, TransGrid proposed that the forecast demands in table 6.5 be used as the threshold figures for determining whether an ex–post demand growth adjustment be applied in calculating the carryover amounts.[431]

Table 6.5: TransGrid's proposed forecast demand growth for EBSS (MW)

	2009–10	2010–11	2011–12	2012–13	2013–14
Low	13 940	14 080	14 310	14 410	14 510
High	15 730	16 180	16 810	17 320	17 860

Source: TransGrid, *Revised revenue proposal*, p. 87.

AER considerations

Consistent with its position in the draft decision, the AER considers it reasonable for a growth adjustment to only be applied if actual demand is outside the range of scenarios modelled in developing TransGrid's revenue proposal. The AER notes, however, that the growth scenarios it cited in its draft decision were not those used by TransGrid to develop its revenue proposal. Consequently, the AER considers it reasonable that an ex post demand growth adjustment only be applied if actual demand growth is outside the low and high growth scenarios in table 6.5, as proposed by TransGrid.

427 AER, *Draft decision*, p. 156.
428 AER, *Draft decision*, p. 156.
429 TransGrid, *NSW annual planning report 2008*, p. 23.
430 TransGrid, *Revised revenue proposal*, p. 87.
431 TransGrid, *Revised revenue proposal*, p. 87.

6.5 AER conclusion

The AER has determined a total opex efficiency allowance under the ECFM of $15.1 million ($2008–09) for TransGrid over the next regulatory control period as shown in table 6.6.

Table 6.6: AER conclusion on TransGrid's opex efficiency allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Opex efficiency allowance	5.7	4.5	5.4	2.2	–2.7	15.1

To account for any difference between actual opex in 2008–09 and TransGrid's forecast, an error correction mechanism will be applied at the next revenue reset. The adjustment amount will be equivalent to the difference between TransGrid's forecast opex for 2008–09 and the actual opex for that year carried forward to each year of the next regulatory control period, adjusted for the time value of money. As outlined in section 6.5.2 of the draft decision, the adjustment amount will be allocated within the 2014–19 regulatory control period having regard to the magnitude of the adjustment amount and potential price volatility impacts.

The AER will apply the EBSS to TransGrid for the next regulatory control period. In the event that actual demand growth is outside the range of scenarios modelled in the development of TransGrid's approved forecast capex and for the purposes of the EBSS, forecast opex will be adjusted based on the same models (opex and capex) used to develop TransGrid's approved forecast opex to incorporate the impact of actual demand growth on the commissioning of new assets.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives costs.

These categories are in addition to the costs of pass through events that are explicitly excluded by EBSS.

The forecast controllable opex for TransGrid outlined in table 6.7 will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[432]

[432] AER, *TNSP EBSS*, p. 7.

Table 6.7: AER forecast controllable opex for EBSS purposes ($m, 2007−08)

	2009–10	2010–11	2011–12	2012–13	2013–14
Total forecast opex	152.9	144.9	148.2	155.6	156.1
Adjustment for debt raising costs	1.9	2.1	2.2	2.4	2.6
Adjustment for self insurance costs	1.8	1.8	1.8	1.8	1.8
Adjustment for insurance costs	5.5	5.9	6.3	6.7	6.9
Adjustment for superannuation costs	6.0	6.0	6.0	5.9	5.7
Adjustment for non–network alternatives	22.6	7.1	7.1	7.1	7.1
Forecast opex for EBSS purposes	115.0	122.0	124.7	131.7	131.9

Note: Totals may not add up due to rounding.

7 Depreciation

7.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision regarding the annual allowances for regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB). It also sets out the AER's assessment of TransGrid's proposed asset lives used in the post–tax revenue model (PTRM) to calculate its depreciation schedule which is then used to determine the regulatory depreciation allowance for the next regulatory control period. There were no submissions received on this issue.

7.2 AER draft decision

The AER considered that TransGrid's proposed depreciation schedule did not comply with the NER requirements and therefore recalculated the depreciation allowance. Specifically, the AER revised TransGrid's proposed asset lives to align the treatment of standard lives for replacement asset classes with augmentation asset classes. The AER also reviewed TransGrid's proposed method for transitioning to recognise its capex on a partially as–incurred approach and considered that it had been implemented appropriately in the PTRM.[433]

On the basis of the approved asset lives, opening RAB, forecast capex allowance and the transitional arrangement to recognise capex on a partially as–incurred approach, the AER determined TransGrid's depreciation schedule and regulatory depreciation allowance for the next regulatory control period as set out in table 7.1.

Table 7.1: AER draft decision on TransGrid's regulatory depreciation allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Straight-line depreciation	179.9	193.1	195.5	218.4	240.7	1027.6
Less: inflation adjustment on RAB	108.0	120.5	130.9	144.9	158.0	662.3
Regulatory depreciation	71.9	72.6	64.6	73.5	82.7	365.3

Source: AER, *Draft decision*, p. 162.

7.3 Revised revenue proposal

TransGrid accepted all elements of the draft decision on depreciation except for the change to the standard asset lives for the replacement asset category of asset classes.[434] In TransGrid's opinion, and based on advice from NERA Economic Consulting (NERA):[435]

433 AER, *Draft decision*, pp. 161–162.
434 TransGrid, *Revised revenue proposal*, p. 88.
435 TransGrid, *Revised revenue proposal*, pp. 89–92.

- the AER had not expressed why it rejected TransGrid's use of a replacement asset category of asset classes and corresponding standard asset lives
- there is no NER requirement that the regulatory life should reflect the technical life of an asset
- the AER is correct in assuming that large replacements assets such as transformers and reactors would be stored, refurbished and re–used
- the AER is incorrect in assuming that other assets such as switch gear would be reused.

7.4 Consultant review

The AER engaged PB to undertake a review of TransGrid's replacement program and projects, and the associated impact to the standard lives of replacement assets. Specifically, PB was required to advise on whether the replacement assets covering the replacement category of assets proposed by TransGrid would achieve their technical asset lives as represented by the augmentation category of asset lives.

PB concluded that the vast majority of capitalised replacement assets should achieve technical lives consistent with identical assets installed for augmentation purposes across the asset classes defined by TransGrid.[436] PB also advised that:[437]

- Minor expenditure that does not extend asset lives should be expensed rather than capitalised in accordance with TransGrid's capitalisation policy. PB considered this should adequately cover a large proportion of minor component replacements.
- Advanced replacement of some minor components, primarily secondary systems and communications asset classes, may be required and should be justified on a case by case basis in an economic manner. PB considered that this should be by exception as modern, standardised assets will not require advanced replacement.
- TransGrid's proposed approach to depreciating all of its new replacement assets for regulatory purposes is inconsistent with its documented asset management plans and expectations for replacement assets.
- At project and program levels, TransGrid has not substantiated its proposed systematic treatment of replacement capex in terms of allocating these asset classses with lower standard asset lives through relevant examples.
- In considering TransGrid's forecast capex replacement projects and programs over the next regulatory control period, PB found no evidence to suggest that the replacement assets would not achieve the technical life of similar augmentation driven assets.

PB's findings on TransGrid's proposed treatment of standard lives for new replacement assets drew upon its review of TransGrid's revenue proposal and revised revenue proposal, and knowledge of TransGrid's asset management practices and plans gained through that review.

436 PB, *TransGrid revised revenue proposal: Standard asset lives for replacement asset classes*, 21 April 2009, p. 14.

437 PB, *Standard asset lives*, p. 14.

7.5 Issues and AER considerations

In the draft decision, the AER rejected TransGrid's proposal to split the standard asset lives between augmentation and replacement asset categories and decided not to accept the standard asets lives proposed for the replacement asset category of asset classses. This was on the basis that TransGrid's proposed depreciation schedules did not conform to the NER requirements.[438]

The AER does not accept TransGrid's suggestion that it has not provided any reasons for rejecting TransGrid's proposed standard asset lives for the replacement asset category of asset classes.[439] The AER's consideration and assessment of TransGrid's proposal is set out in section 7.4.1 of the draft decision. In brief, the reasons are that:[440]

- The AER was not satisfied that replacement assets should have a lower standard life than that applied to augmentation driven assets for the purposes of calculating regulatory depreciation. The AER expects that for the replacement of large assets in a substation the economic life of the replacement asset would be equal to a new development.
- TransGrid did not satisfy the AER of the need to split the standard asset lives between augmentation and replacement asset categories.

TransGrid and NERA are primarily arguing that the economic life of an asset should be the economic life of the larger of the two assets.[441] TransGrid argued that this is because the asset will only provide benefits to consumers while it is part of a larger asset. The AER considers, taking account of PB's advice, that this is inconsistent with TransGrid's own internal policies and asset management plans,[442] which are designed to maximise the operational life of all assets.[443] This includes refurbishing and re–using replaced assets and therefore extending their useful life.[444] The AER considers that just because an asset is relocated, it does not decrease the benefit consumers derive from the asset.

TransGrid has not offered any specific examples supporting its proposal that replacement assets consistently have a shorter asset life than identical assets installed for the purposes of augmentation. PB has concluded from its review of TransGrid's forecast capex replacement projects and programs over the next regulatory control period that:[445]

- there is no evidence to suggest replacement assets would not achieve the typical technical life of identical augmentation driven assets
- given the wholesale nature of various switchyard rebuilds, the assets should achieve standard technical lives equivalent to augmentation asset lives
- there was reasonable evidence that a number of the projects included augmentation assets

438 AER, *Draft decision*, pp. 160–161.
439 TransGrid, *Revised revenue proposal*, p. 90.
440 AER, *Draft decision*, pp. 160–161.
441 TransGrid, *Revised revenue proposal*, appendix O, p. 7.
442 TransGrid, *Network 30 year asset management plan 2009–2039*, confidential, p. 24.
443 PB, *Standard asset lives*, p. 3–4, 6.
444 PB, *Standard asset lives*, p. 3.
445 PB, *Standard asset lives*, pp. 7–14.

- there were a number of examples where TransGrid is relocating transformers and switchgear to make use of serviceable equipment at alternative locations.

Therefore, PB advised that the vast majority of TransGrid's capitalised replacement assets should achieve technical lives consistent with identical assets installed for augmentation purposes across the asset types defined by TransGrid.[446]

In the AER's view the economic and technical lives of an asset should generally coincide. The economic life of an asset is adopted for regulatory depreciation purposes as required under clause 6A.6.3 of the NER and therefore it is also referred to as the regulatory life. PB supported the AER's view that economic and technical lives generally coincide. However, PB has also offered scenarios of when economic lives are not equivalent to technical lives.[447] These are consistent with NERA's arguments for scenarios when shorter economic lives should also apply.[448] PB indicated that these scenarios are the exception rather than the rule of asset replacement and would only apply to TransGrid in a minority of circumstances and to a minority of replacement assets because most modern, standardised assets will not require advanced replacement. PB, however, accepted that some minor components may require advanced replacement and this should be justified on a case–by–case economic basis.[449]

The AER notes that PB's review also found some issues with TransGrid's proposed treatment of replacement forecast capex and associated standard asset lives in the PTRM. For example, TransGrid has only allocated the capex for transformers it is refurbishing into the augmentation category of asset class, as opposed to the capex for all of its replacement transformers. This is despite TransGrid appearing to accept that the replacement of large assets, such as transformers, would be expected to have an economic life equal to a new development.[450] Further, it is not apparent why TransGrid is allocating capex related to the security/compliance category into the replacement category of asset classes instead of allocating some of the capex into the augmentation category of asset classes.

Overall, taking account of PB's advice and an assessment of the material put forward, the AER does not consider that TransGrid's proposal to allocate the majority of new replacement capex into the replacement category of asset classes, with reduced standard asset lives, for regulatory depreciation purposes to be reasonable under clause 6A.6.3(b)(1) of the NER. The AER is not satisfied that these new replacement assets would not achieve the economic lives that would be consistent with the technical lives for new augmentation assets. For the reasons discussed and as a result of the AER's analysis of TransGrid's revised revenue proposal, the AER confirms its draft decision and does not accept the standard asset lives proposed for the replacement asset category of asset classes.

446 PB, *Standard asset lives*, pp. 7–13.
447 PB, *Standard asset lives*, pp. 4–5.
448 TransGrid, *Revised revenue proposal*, Appendix O, p. 7.
449 PB, *Standard asset lives*, p. 14.
450 TransGrid, *Revised revenue proposal*, p. 91.

7.6 AER conclusion

The AER has reviewed the inputs to the PTRM used by TransGrid to calculate the depreciation schedule in accordance with clause 6A.6.3 of the NER. The AER maintains its draft decision and does not consider that TransGrid's proposal to allocate the majority of new replacement capex into the replacement category of asset classes, with reduced standard asset lives, for regulatory depreciation purposes to be reasonable. The AER is not satisfied that these new replacement assets would not achieve the economic lives that would be consistent with the technical lives for new augmentation assets.

Accordingly, the AER does not accept the standard asset lives proposed for the replacement asset category of asset classes. The AER considers that TransGrid's proposed depreciation schedule does not conform with the NER requirements and therefore has recalculated the depreciation allowance for this final decision.

On the basis of the approved asset lives, opening RAB, forecast capex allowance and the transitional arrangements to recognise capex on a partially as–incurred approach, the AER has detemined TransGrid's depreciation schedule. The depreciation schedule is used to calculate the regulatory depreciation allowance for the next regulatory control period in accordance with clause 6A.6.3(a)(2)(ii), as set out in table 7.2.

Table 7.2: AER conclusion on TransGrid's regulatory depreciation allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Straight-line depreciation	179.0	191.6	193.5	215.6	238.2	1018.0
Less: inflation adjustment on RAB	104.4	116.5	126.7	140.3	152.8	640.7
Regulatory depreciation	74.6	75.2	66.8	75.3	85.4	377.3

8 Service target performance incentives

8.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on the service target performance regime and the values to be applied to TransGrid for the next regulatory control period.

The service target performance incentive scheme (the scheme) aims to encourage TNSPs to maintain or improve the quality of service provided to customers. The scheme has two components, a service component and a market impact of transmission congestion (MITC) component (the market impact component).

Only the service component of the scheme is applied to TransGrid in the current regulatory control period. It provides incentives in the operation of the network to maximise transmission circuit availability, minimise loss of supply event frequency and minimise average outage duration. This means that TransGrid needs to consider the impact of its actions on customers when making operational management decisions, such as taking lines out of service for maintenance or augmentation.

The AER has recently developed an additional component for the scheme based on the MITC. The market impact component will apply to TransGrid during the next regulatory control period. The market impact component supplements the service component of the scheme by targeting outages that have an adverse impact on generator dispatch outcomes. The scheme incorporates a market impact parameter based on historical MITC data and provides financial rewards for improvements in performance standards against a performance target.

8.2 AER draft decision

The AER largely accepted TransGrid's service target performance incentive proposal, but also made a number of adjustments. In summary, the AER:[451]

- accepted TransGrid's revised proposed performance targets for the transmission circuit availability parameters
- accepted TransGrid's proposed loss of supply event frequency parameter performance targets as they were based on the average performance of the most recent five years and met the requirements of the scheme
- did not accept the average outage duration parameter performance target proposed in TransGrid's revenue proposal due to the discrepancies identified by PB and TransGrid
- accepted TransGrid's proposed methodology for setting the collar values for the transmission circuit availability and average outage duration parameters
- did not accept the transmission circuit availability parameters collar values proposed by TransGrid in its revenue proposal

[451] AER, *Draft decision*, pp. 169–181.

- did not accept the collar values proposed by TransGrid in its revenue proposal for the average outage duration parameter. The performance target for the average outage duration parameter was revised during PB's review and as a result the collar values were also revised
- accepted TransGrid's proposed collar values for the loss of supply event frequency parameters
- accepted the method proposed by TransGrid for calculating the cap values for transmission circuit availability parameters
- accepted TransGrid's revised proposed cap values for transmission circuit availability parameters
- accepted TransGrid's proposed cap values for loss of supply event frequency parameters
- accepted TransGrid's proposed methodology for calculating the cap for the average outage duration parameter
- did not accept TransGrid's proposed cap value for the average outage duration parameter
- accepted TransGrid's proposed weightings
- did not accept TransGrid's proposed performance target of 2858 dispatch intervals for the market impact component and substituted a performance target of 2857 dispatch intervals to account for the five non–excluded degenerate solutions.

The draft decision on TransGrid's performance targets, caps, collars and weightings for the service component of the scheme during the next regulatory control period are set out in table 8.1.

Table 8.1: AER draft decision on TransGrid's service component performance targets, caps, collars, and weightings

Parameter	Collar	Target	Cap	Weighting
Transmission circuit availability (%)				*MAR (%)*
Transmission line availability	99.05	99.26	99.36	0.20
Transformer availability	97.26	98.55	98.84	0.15
Reactive plant availability	98.65	99.12	99.33	0.10
Loss of supply event frequency (no.)				*MAR (%)*
> 0.05 (x) system minutes	7	4	2	0.25
> 0.25 (y) system minutes	2	1	0	0.10
Average outage duration (minutes)				*MAR (%)*
Total	999	824	649	0.20

Source: AER, *Draft decision*, p. 181.

The draft decision on TransGrid's performance target, cap and weighting for the market impact component of the scheme are set out in table 8.2.

Table 8.2: AER draft decision on TransGrid's market impact component performance target, cap and weighting

Parameter	Values		
Market impact	**Target**	**Cap**	**Weighting**
	Number of dispatch intervals with a marginal value greater than $10/MWh		*MAR (%)*
	2857	0	2.0

Source: AER, *Draft decision*, p. 181.

8.3 Revised revenue proposal

TransGrid has implemented the draft decision in respect of the service component and the market impact component of the scheme.[452] Subsequent to submitting its revised revenue proposal, TransGrid advised the AER that due to changes in capex modelling for its revised revenue proposal, the transformer availability parameter performance target, cap and collar had increased.[453]

8.4 Submissions

The AER received one submission from the Energy Users Association of Australia (EUAA). The EUAA stated that it did not agree that performance targets (and therefore caps and collars) should be reduced due to forecast capital works.[454] It also requested the AER consider a penalty scheme for the market impact component of the scheme.[455]

8.5 Issues and AER considerations

8.5.1 Service component

8.5.1.1 Adjustment to performance targets, caps and collars for capital works

AER draft decision

The AER engaged PB to undertake a review of TransGrid's service component historical data and proposed adjustments to the service component performance targets based on forecast capital works (adjustments to performance targets for the volume of capital works are allowed under clause 3.3(k)(2) of the scheme). Based on that review, the AER and PB were satisfied that the adjustments to performance targets for forecast capital works in the next regulatory control period were reasonable.[456]

452 TransGrid, *Revised revenue proposal*, pp. 95–96.
453 TransGrid, *Response to issue 326*, 25 February 2008.
454 EUAA, p. 21.
455 EUAA, p. 22.
456 AER, *Draft decision*, p. 173.

Service component caps and collars are calculated by reference to the proposed performance targets and were therefore calculated by reference to targets adjusted for forecast capital works.

Submissions

The EUAA did not agree that performance targets, caps and collars should be reduced due to capital works.[457]

AER considerations

Adjustments to performance targets are allowed under clause 3.3(k)(2) of the scheme in recognition that where there is a substantial change in a TNSP's capital works program, historical performance may not be an achievable goal for future performance. The service component of the scheme is primarily concerned with influencing the operational management decisions of TNSPs to ensure that they consider the interests of users when seeking to reduce opex. Where there is a material change in the outages associated with an increased capital works program (as forecast by TransGrid), operational management decisions alone may not make it possible for the TNSP to achieve a performance target based on historical performance due to the large number of outages required. In these circumstances, the incentive mechanism will be undermined if there is no adjustment to the performance target.

The AER also notes that any adjustment to performance targets will, in accordance with clause 3.3(e) of the scheme, have a consequential impact on the caps and collars for the next regulatory control period.

The AER maintains its view that it is appropriate for TransGrid's performance targets to be adjusted for the forecast increase in the volume of capital works over the next regulatory control period.

8.5.1.2 Updating transformer availability parameter values

TransGrid updated its transformer availability parameter performance target, cap and collar as a result of changes to its forecast capex program. The AER has assessed the data provided by TransGrid and is satisfied the increase in performance target (and corresponding increases in cap and collar values), is appropriate. The updated parameter values are set out in table 8.3.

Table 8.3: Updated transformer availability parameter performance target, cap and collar (per cent)

Transformer availability parameter	Collar	Target	Cap
AER final decision	97.33	98.61	98.89

457 EUAA, p. 21.

8.5.2 Market impact component

Introduction of a symmetrical financial incentive

Submissions

The EUAA accepted the draft decision in respect of the market impact component, however it restated its preference for a market impact component which provides for a penalty as well as a bonus.[458]

AER considerations

The scheme provides for a bonus only to be applied to the market impact component. In developing the scheme, the AER noted that the market impact component is, to some extent, experimental and unproven and therefore it is difficult to predict a TNSP's performance against it. The AER considered it appropriate not to apply a penalty (as well as a bonus) for the market impact component though it noted that it may review the asymmetric incentive of the component in the future.[459]

8.6 AER conclusion

The parameter definitions that apply to TransGrid for the next regulatory control period are set out in appendix B of the scheme. The definition for system minute was set out in the draft decision as it was not provided in the scheme. The system minute definition is also set out in appendix F of this final decision.

As a result of changes to the transformer availability parameter values the performance incentive curve for transformer availability has also changed. The performance incentive curves that apply to TransGrid are set out in appendix G of this final decision.

The service component performance targets, caps, collars and weighting to be applied to TransGrid during the next regulatory control period are set out in table 8.4.

---

[458] EUAA, p. 22.

[459] AER, *Final decision, Electricity transmission network service providers–Service target performance incentive scheme (incorporating incentives based on the market impact of transmission congestion)*, March 2008, p. 20.

Table 8.4: AER conclusion on TransGrid's service component performance targets, caps, collars and weightings

Parameter	Collar	Target	Cap	Weightings
Transmission circuit availability (%)				*MAR (%)*
Transmission line availability	99.05	99.26	99.36	0.20
Transformer availability	97.33	98.61	98.89	0.15
Reactive plant availability	98.65	99.12	99.33	0.10
Loss of supply event frequency (No.)				*MAR (%)*
>0.05 (x) system minutes	7	4	2	0.25
>0.25 (y) system minutes	2	1	0	0.10
Average outage duration (minutes)				*MAR (%)*
Total	999	824	649	0.20

TransGrid's market impact component target, cap and weighting are set out in table 8.5.

Table 8.5: AER conclusion on TransGrid's market impact component performance target, cap and weighting

Parameter	Values		
Market impact	**Target**	**Cap**	**Weighting**
	Number of dispatch intervals with a marginal value greater than $10/MWh		*MAR (%)*
	2857	0	2.0

9 Maximum allowed revenue

9.1 Introduction

This chapter sets out the AER's calculation of TransGrid's maximum allowed revenue (MAR) for the provision of prescribed transmission services for each year of the next regulatory control period, using the building block approach.

9.2 AER draft decision

Based on its assessment of the building block components and using the post–tax revenue model (PTRM), the AER determined the MAR for TransGrid that increases from $678 million in 2009–10 to $891 million in 2013–14 ($nominal). The AER determined a nominal expected MAR (smoothed) for TransGrid that increases from $678 million in 2009–10 to $891 million in 2013–14. The total revenue cap for TransGrid over the next regulatory control period was determined to be $3906 million. Table 9.1 sets out the annual building block calculations.

Table 9.1: AER draft decision on annual building block revenue requirement ($m, nominal)

	2009–10	20010–11	2011–12	2012–13	2013–14	Total
Return on capital	415.9	464.2	504.3	557.9	608.5	2550.8
Regulatory depreciation	71.9	72.6	64.6	73.5	82.7	365.3
Opex allowance	168.1	162.2	171.7	182.5	184.1	868.5
Opex efficiency allowance[a]	4.5	3.2	4.1	1.0	–3.9	8.9
Net tax allowance	22.5	23.7	23.0	26.0	29.0	124.4
Annual building block revenue requirement (unsmoothed)	678.4	722.7	763.6	840.0	904.3	3909.0
Maximum allowed revenue (smoothed)	678.4	726.3	777.5	832.4	891.1	3905.7
X factor (%)	n/a	–4.39	–4.39	–4.39	–4.39	n/a

Source: AER, *Draft decision*, p. 189.
(a) An allowance for opex efficiency resulting from the carry forward mechanism applied in the current regulatory control period.

The AER estimated that the increase in average transmission charges under the draft decision would add approximately $4.00 to the average residential customer's annual bill of $983 (0.4 per cent).

9.3 Revised revenue proposal

TransGrid applied the post–tax building block approach to calculate its revised revenue requirement. TransGrid's revised revenue requirements were determined on the basis of a nominal opening RAB of $4276 million.[460] It proposed nominal unsmoothed revenues of $707 million in 2009–10, increasing to $973 million in 2013–14.[461] The proposed nominal expected MAR (smoothed) increases from $707 million in 2009–10 to $960 million in 2013–14. TransGrid's MAR for the final year of its current regulatory control period (2008–09) is $622 million. Table 9.2 summarises TransGrid's total proposed annual building block revenue requirement (unsmoothed) and the expected MAR for each year of the next regulatory control period.[462]

Table 9.2: TransGrid's proposed annual building block revenue requirement and maximum allowed revenue ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Return on capital	435.5	486.9	530.9	593.4	649.7	2696.4
Regulatory depreciation	71.5	73.4	66.6	78.0	88.6	378.1
Operating expenditure[a]	175.6	173.8	185.7	199.7	203.5	938.3
Tax payable	48.0	50.7	49.7	56.5	63.2	268.1
Value of franking credit	–24.0	–25.3	–24.8	–28.3	–31.6	–134.0
Annual building block revenue requirement (unsmoothed)	706.6	759.4	808.1	899.4	973.3	4146.8
Maximum allowed revenue (smoothed)	706.6	763.0	823.8	889.5	960.4	4143.3
X factor (%)	n/a	–5.26	–5.26	–5.26	–5.26	n/a

Source: TransGrid, *Revised revenue proposal*, p. 99.
(a) Includes an allowance for opex efficiency resulting from the carry forward mechanism applied in the current regulatory control period.

Consistent with the approach applied in the draft decision, TransGrid has calculated its expected MAR over the next regulatory control period by setting the first year's MAR equal to the first year's annual building block revenue requirement and applying an X factor of –5.26 per cent to escalate its MAR annually for each of the four remaining years.[463]

TransGrid stated that its revised revenue proposal would result in an average annual increase in transmission charges of 4.4 per cent (real). As TransGrid's costs represent about 6 per cent of the total delivered price for the average energy user, the impact on the price to consumers is estimated to be about $4.90 a year for the typical household in NSW.[464]

460 TransGrid, *Revised revenue proposal*, p. 97.
461 TransGrid, *Revised revenue proposal*, p. 98.
462 While the total value of the annual building block revenue requirement is different to the total value of the expected MAR (smoothed), the two are equivalent in net present value terms.
463 TransGrid, *Revised revenue proposal*, p. 99.
464 TransGrid, *Revised revenue proposal*, pp. 99–100.

9.4 AER assessment of building blocks

9.4.1 Opening asset base and roll forward

The NER requires that the roll forward of TransGrid's RAB, as at the end of each year of the next regulatory control period, be calculated by taking the opening RAB value, adjusting it for inflation, adding any additional capex, and subtracting disposals and depreciation for the year. The closing RAB value for one year then becomes the opening RAB value for the following year.

As discussed in chapter 2, the AER has determined the opening value of TransGrid's RAB to be $4218 million as at 1 July 2009. Based on this opening value, the AER has modelled TransGrid's RAB over the next regulatory control period as shown in table 9.3.

Table 9.3: AER roll forward of TransGrid's regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	4217.5	4705.6	5119.1	5669.7	6175.2
Net capital expenditure	562.6	488.7	617.4	580.9	445.5
Inflation adjustment on opening RAB	179.0	191.6	193.5	215.6	238.2
Straight-line depreciation	104.4	116.5	126.7	140.3	152.8
Closing RAB	4705.6	5119.1	5669.7	6175.2	6535.3

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

9.4.2 Forecast capital expenditure

As discussed in chapter 3, the AER has determined a forecast capex allowance for TransGrid of $2405 million ($2007–08) during the next regulatory control period. In 2008–09 dollar terms the forecast capex allowance is $2468 million.[465] The annual nominal allowance is shown in table 9.3 and is used to calculate the roll forward value of TransGrid's RAB.[466]

9.4.3 Weighted average cost of capital

The AER has determined the annual return on capital allowance by applying the weighted average cost of capital (WACC) to TransGrid's opening RAB for each year of the next regulatory control period.

As discussed in chapter 4, the nominal vanilla WACC of 8.79 per cent is based on a post–tax nominal return on equity of 10.29 per cent and a pre–tax nominal return on debt of 7.78 per cent. Table 9.5 shows the AER's return on capital allowance.

465 The forecast capex allowance in 2008–09 dollar terms includes the equity raising costs allowance.

466 In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes.

9.4.4 Operating expenditure

As discussed in chapter 5, the AER has determined a forecast opex allowance for TransGrid of $758 million ($2007–08) during the next regulatory control period. In 2008–09 dollar terms the forecast opex allowance is $786 million. Table 9.5 shows the annual opex allowance.

9.4.5 Operating expenditure efficiency allowance

As discussed in chapter 6, the AER has determined an opex efficiency allowance under the efficiency carry forward mechanism of $15.1 million ($2008–09) for TransGrid during the next regulatory control period. Table 9.5 shows the annual efficiency allowance.

9.4.6 Depreciation

As discussed in chapter 7 and using the post–tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Table 9.5 shows the resulting figures.

In modelling the applicable straight-line depreciation in the PTRM, the AER has based its calculations on the approved average remaining lives for existing assets and standard lives for new assets (by asset classes).

9.4.7 Estimated taxes payable

Using the PTRM, the AER has modelled TransGrid's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent debt benchmark gearing, rather than TransGrid's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6A.6.4(a) of the NER, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Under the post–tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost–reflective revenue outcomes. The effective tax rate is defined as the difference between pre–tax and post–tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 24 per cent for this final decision. Table 9.4 shows the AER's estimate of the allowance for TransGrid's tax payments.

Table 9.4: AER modelling of net tax allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Tax payable	38.8	40.3	38.4	43.6	48.7	209.8
Value of imputation credits	–19.4	–20.1	–19.2	–21.8	–24.4	–104.9
Net tax allowance	19.4	20.1	19.2	21.8	24.4	104.9

Note: Totals may not add up due to rounding.

9.5 AER determination—maximum allowed revenue

9.5.1 Annual building block revenue requirment

Based on its assessment of the building block components and using the PTRM, the AER determines an annual building block revenue requirement for TransGrid that increases from $633 million in 2009–10 to $832 million in 2013–14 ($nominal). Table 9.5 shows the annual building block calculations.

Table 9.5: AER final decision on annual building block revenue requirement ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Return on capital	370.6	413.4	449.8	498.1	542.6	2274.4
Regulatory depreciation	74.6	75.2	66.8	75.3	85.4	377.3
Opex allowance	162.5	157.8	165.4	178.0	182.9	846.5
Opex efficiency allowance[a]	5.8	4.7	5.8	2.5	–3.0	15.7
Net tax allowance	19.4	20.1	19.2	21.8	24.4	104.9
Annual building block revenue requirement (unsmoothed)	632.8	671.3	706.9	775.7	832.2	3618.9

(a) An allowance for opex efficiency resulting from the carry forward mechanism applied in the current regulatory control period.

The AER's final decision on the total annual building block revenue requirement is lower than that in the draft decision and is largely driven by a lower return on capital building block. The return on capital building block is determined by multiplying the WACC by the opening RAB. In this final decision, the AER has determined a lower opening RAB—updated for actual 2008–09 CPI which is lower than forecast in the draft decision—and a lower WACC largely driven by a fall in the risk–free rate—commensurate with monetary policy and softening in economic growth.

9.5.2 Expected maximum allowed revenue—smoothed

The net present value (NPV) of the annual building block revenue requirement for the next regulatory control period has been calculated to be $2798 million. Based on this NPV amount, the AER determines a nominal expected MAR (smoothed) for TransGrid that increases from $633 million in 2009–10 to $820 million in 2013–14, as shown in table 9.6. The total revenue cap for TransGrid over the next regulatory control period is \$3616 million. TransGrid's MAR for the next regulatory control period is to be calculated using the formula described part 1 of the AER's transmission determination for TransGrid.[467]

Table 9.6: AER final decision on the maximum allowed revenue (\$m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
MAR (smoothed)	632.8	675.1	720.2	768.3	819.6	3616.0
X factor (%)	n/a[a]	–4.10	–4.10	–4.10	–4.10	n/a

(a) The MAR for 2009–10 is set as \$632.8 million and TransGrid is not required to apply an X factor. The MAR in the first year of the next regulatory control period (2009–10) is around 1.8 per cent higher than the MAR in the final year of the current regulatory control period (2008–09).

To determine the expected MAR (smoothed) over the next regulatory control period the AER has set the first year MAR equal to the annual building block revenue requirement for that year and applied an X factor of –4.10 per cent in subsequent years, as shown in table 9.6. The AER considers that this profile of X factors results in an expected MAR in the final year of the regulatory control period that is as close as reasonably possible to the annual building block revenue requirement for that year, and is therefore in accordance with clause 6A.6.8(c)(2) of the NER. The AER's revenue determination for TransGrid is set out in part 1 of the transmission determination.

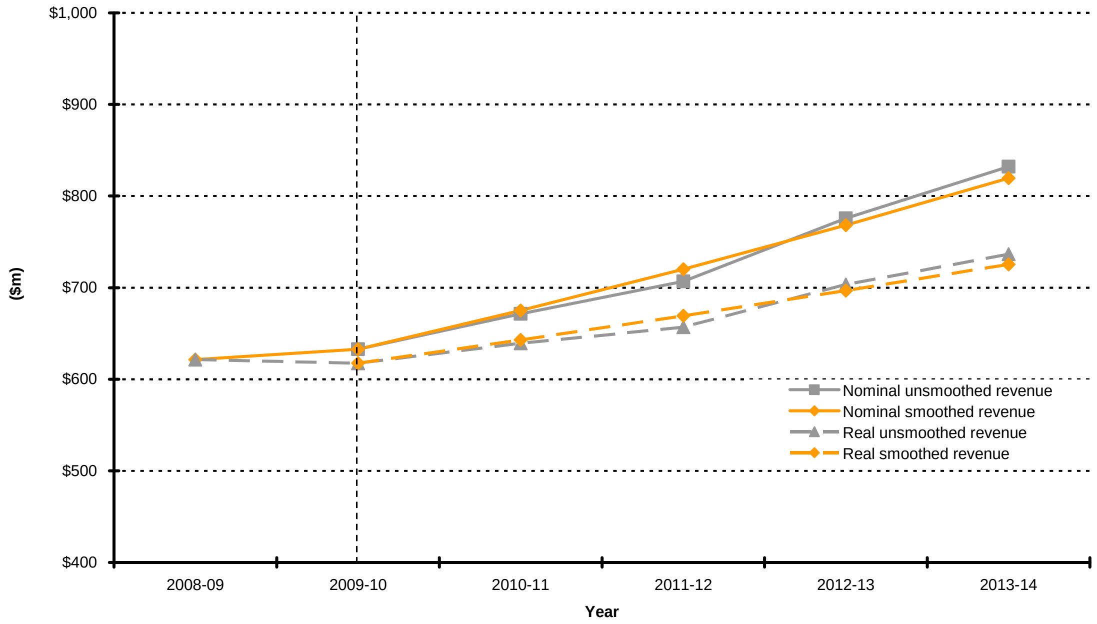
The average revenue increase of 5.7 per cent per annum (nominal) over the next regulatory control period consists of an initial increase of 1.8 per cent from 2008–09 to 2009–10 and a subsequent average annual increase of 6.7 per cent during the remainder of the next regulatory control period.

In real terms (\$2008–09), the average revenue increase of 3.2 per cent per annum over the next regulatory control period consists of an initial decrease of 0.6 per cent from 2008–09 to 2009–10 and a subsequent average annual increase of 4.1 per cent during the remainder of the next regulatory control period.

Figure 9.1 shows the revenue path allowed in this final decision (both smoothed and unsmoothed) in nominal and real terms.

467 The formula is also described in section 9.3 of the draft decision.

Figure 9.1: Revenue path from 2008–09 to 2013–14 ($m)



9.6 Average transmission charges

TransGrid's MAR for the next regulatory control period is established through a building block approach. While the AER assesses TransGrid's proposed pricing methodology, actual transmission charges established at particular connection points are not approved by the AER. TransGrid establishes its transmission charges in accordance with its approved pricing methodology and the NER.

The effect of the final decision on average transmission charges can be estimated by taking the annual MAR and dividing it by forecast annual energy delivered in NSW.[468] Based on this approach, the AER estimates that this final decision will result in a 4.8 per cent per annum (nominal) increase in average transmission charges in the next regulatory control period or an increase of 2.3 per cent per annum in real terms ($2008–09).

The nominal increase in the average transmission charges is greater than the average growth in the level of peak demand in NSW, which is forecast to increase by 2.5 per cent per annum over the next regulatory control period.[469] The increase in average transmission charges is primarily because of:

- a higher opening RAB than was forecast in the ACCC 2005 revenue cap decision
- the higher cost of replacing and maintaining assets
- the need for increased capex associated with maintaining reliability standards
- increased opex due to a growing asset base.

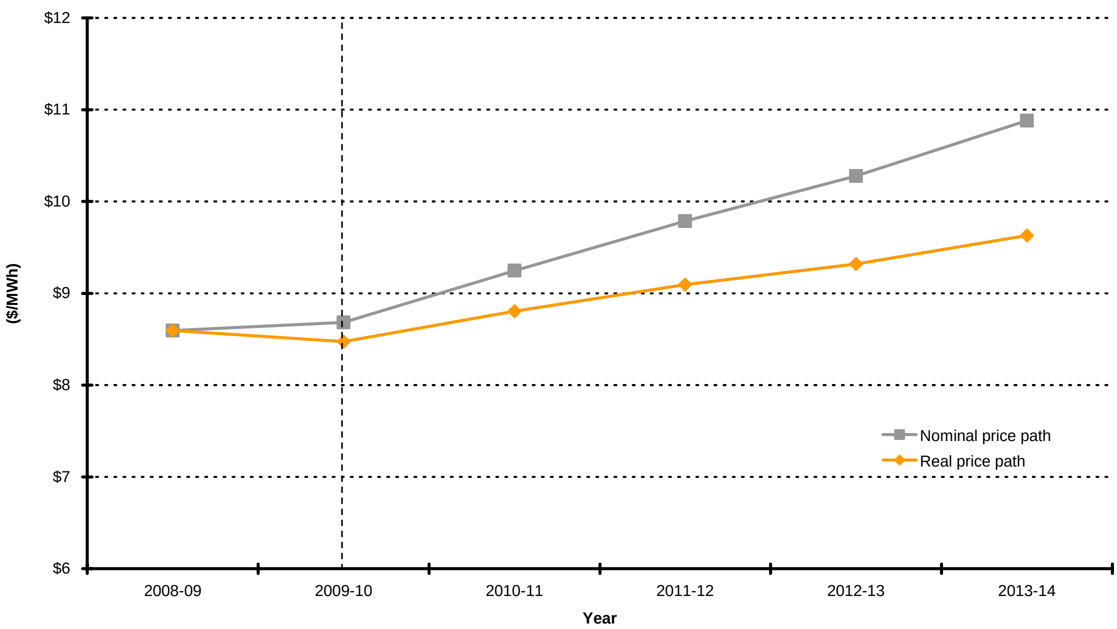
468 The forecast energy delivered (NSW scheduled energy supplied at connection points) figures were obtained from TransGrid, *Annual Planning Report*, June 2008, p. 88.

469 TransGrid, *Annual planning report*, June 2008, p. 89.

Transmission charges represent approximately 6 per cent on average of end user electricity charges in NSW. The AER estimates that the increase in average transmission charges under this final decision will add approximately $2.80 to the average residential customer's annual bill of $983 (0.3 per cent).[470]

Figure 9.2 shows the resulting average price path of this final decision during the next regulatory control period compared with the average price for the final year of the current regulatory control period in nominal and real terms ($2008–09). The average transmission charge in 2008–09 is $8.60 per MWh. Nominal average transmission charges are forecast to increase from around $8.70 per MWh in 2009–10 to $10.90 per MWh in 2013–14. Real average transmission charges are forecast to increase from around $8.50 per MWh in 2009–10 to $9.60 per MWh in 2013–14.

Figure 9.2: Price path from 2008–09 to 2013–14 ($/MWh)



[470] IPART, *Overview of final report and determination on electricity retail prices in NSW—From* 1 July *2007 to 30 June 2010*. The average customer bill was calculated using 2008–09 data for medium residential usage and an average across the three standard retailers in NSW.

10 Negotiating framework for negotiated transmission services

10.1 Introduction

This chapter sets out the AER's decision on TransGrid's negotiating framework, relating to negotiated transmission services. There were no submissions received in response to the draft decision.

10.2 AER draft decision

The AER assessed TransGrid's negotiating framework and considered that the negotiating framework in appendix H of the draft decision complied with the NER.

The AER approved TransGrid's negotiating framework for the next regulatory control period.[471]

10.3 Revised revenue proposal

TransGrid did not amend its negotiating framework in its response to the draft decision.[472]

10.4 AER determination

The AER has assessed TransGrid's negotiating framework and considers that the negotiating framework is compliant with clause 6A.9.5(c) of the NER.

The negotiating framework set out in part 2 of the transmission determination will apply to TransGrid for the next regulatory control period.

---

471 AER, *Draft decision*, p. 196.

472 TransGrid, *Revised revenue proposal*, p. 101.

11 Negotiated transmission service criteria

11.1 Introduction

This chapter sets out the AER's decision on the negotiated transmission service criteria (NTSC) to apply to TransGrid. There were no submissions received in response to the draft decision.

11.2 AER draft decision

In accordance with the NER, the AER published its proposed NTSC for TransGrid in June 2008.

The determination by the AER in appendix I of the draft decision specified the NTSC for TransGrid for the next regulatory control period.[473]

11.3 Revised revenue proposal

TransGrid did not address the NTSC in its response to the draft decision.

11.4 AER determination

The negotiated transmission service criteria set out in part 3 of the transmission determination will apply to TransGrid for the next regulatory control period.

[473] AER, *Draft decision*, pp. 321–322.

12 Pricing methodology

12.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on TransGrid's proposed pricing methodology for the next regulatory control period. No submissions were received on this issue.

In accordance with the NER, TransGrid has been appointed the coordinating network service provider for NSW by EnergyAustralia, Country Energy and Directlink Transmission Company (Directlink). As the coordinating network service provider for NSW, TransGrid is responsible for allocation of the aggregate annual revenue requirement for the provision of transmission services in NSW and calculating transmission prices.

12.2 AER draft decision

The AER assessed TransGrid's proposed pricing methodology against part J of the NER and the pricing methodology guidelines (the guidelines).[474] Based on its assessment, the AER decided not to approve TransGrid's proposed pricing methodology.[475]

The NER requires that if the AER refuses to approve any aspect of a proposed pricing methodology, its draft decision must include details of the changes required or the matters to be addressed before the AER will approve the proposed pricing methodology. The AER stated that the matters that TransGrid must address in its revised proposed pricing methodology were:[476]

- to propose an alternative locational pricing structure which is consistent with clause 6A.23.4(e) of the NER and does not include a measure of energy
- to include additional details on its approach to allocating costs to assets that provide both prescribed entry and prescribed exit services.

The AER also stated that it would be beneficial for TransGrid to specify the points in the transmission network where costs will be allocated and prices determined.[477]

12.3 Revised proposed pricing methodology

TransGrid has implemented the draft decision with the exception of specifying the points in the transmission network where costs will be allocated and prices determined.

TransGrid submitted a revised proposed pricing methodology which included a demand based locational pricing structure which it considered complied with the guidelines.[478]

474 AER, *Final Electricity transmission network service providers, pricing methodology guidelines*, October 2007.
475 AER, *Draft decision*, p. 212.
476 AER, *Draft decision*, p. 212.
477 AER, *Draft decision*, p. 212.
478 TransGrid, *Revised revenue proposal*, p. 105.

TransGrid stated that it did not accept the AER's suggestion to include a list of connection points in its revised proposed pricing methodology as:[479]

- the locations where transmission prices are determined are published annually on TransGrid's website
- the inclusion of these points in its revised proposed pricing methodology would be an additional administrative burden
- there is no current requirement in the NER or the guidelines to do so.

12.4 Issues and AER considerations

12.4.1 Cost allocation

AER draft decision

In the draft decision the AER requested TransGrid provide additional clarification on its proposed approach to allocating costs to assets that provide both prescribed entry and prescribed exit services.[480]

Revised revenue proposal

TransGrid did not respond to this matter in its revised revenue proposal or its revised proposed pricing methodology.

AER considerations

The AER requested TransGrid provide additional clarification on its proposed approach to allocating costs to assets that provide both prescribed entry and exit services.[481] In response TransGrid stated that it had included the following clarification in an updated version of its revised proposed pricing methodology:[482]

> TransGrid's approach to connecting both entry and exit customers using common connection assets is to pro–rata the costs based on the MW capacity available to each customer. A pro–rata of costs based on energy is not useful as generator customers only pay for connection costs and do not pay any energy consumption costs. i.e. no payment for usage or postage stamp energy charges under the Rules unless this is mutually negotiated.

The AER considers the clarification is sufficient to comply with sections 2.1(d) and (e) of the guidelines.

479 TransGrid, *Revised revenue proposal*, p. 104.
480 AER, *Draft decision*, p. 212.
481 AER, *Draft decision*, p. 212.
482 TransGrid, Email response to information request, 2 February 2009.

12.4.2 Locational pricing structure

AER draft decision

The AER rejected TransGrid's proposed locational pricing structure. It considered that the inclusion of an energy based locational price was inconsistent with the intent of the AEMC, as outlined by the AEMC in its transmission pricing rule determination.[483]

Revised revenue proposal

TransGrid submitted a revised proposed pricing methodology as part of its revised revenue proposal. It stated that its revised locational pricing structure is in agreement with the pricing methodology guidelines.[484]

TransGrid's revised proposed pricing methodology outlined its proposed approach to locational pricing as:[485]

> TransGrid's future locational component of its charges and prices will be determined on the basis of a maximum monthly demand charge.
>
> The CRNP methodology outlined in S6A.3 of the Rules describes the process for cost allocation for the locational component of prescribed TUOS services, which results in a lump sum dollar amount to be recovered at each connection point as described in Appendix B.
>
> To calculate rates, TransGrid adopts the level and pattern of usage is the same as in the previous financial year. Specifically the maximum demand charge at each connection point is calculated by dividing the amount by the average of the monthly maximum demands in each month at that connection point in the previous financial year (with adjustment for forecast system load growth from the historical period to the period during which the prices will apply) and express the result as a rate in $/kW/month.
>
> Where there are both customer loads and generator auxiliary loads at a connection point, rates are set on the basis of the full load at the point, even though the generator does not pay usage charges.

AER considerations

The AER requested TransGrid provide additional clarification on the calculation of the locational price and charge in its revised proposed pricing methodology. TransGrid responded and provided the following:[486]

> Additional clarification has been added to the revised Pricing Methodology (attached to this response) to address this issue. The original text in section 6.9.2 on pages 12 and 13 has been replaced with the following:
>
> > The locational prices at each connection point, expressed as a different maximum demand rate for each connection point, are determined by applying the following steps:
> >
> > 1. Calculating the lump sum dollar amount to be recovered at the connection point in the manner described in the previous paragraph on a monthly basis;

483 AER, *Draft decision*, pp. 208–209.
484 TransGrid, *Revised revenue proposal*, p. 104.
485 TransGrid, *Proposed pricing methodology 1 July 2009 to 30 June 2014*, January 2009, pp. 12–13.
486 TransGrid, Email response to information request, 2 February 2009.

> 2. Calculating the average of the monthly maximum demands in each month at that connection point in the previous financial year;
>
> 3. Adjusting the outcome of Step 2 for the forecast system load growth from the historical period to the period during which the prices will apply; and
>
> 4. Dividing the results from Step 1 by the results from Step 3 to produce a locational price at that connection point expressed in $/kW/month.
>
> These prices will be published for each connection point each year prior to the 15 May of that year on TransGrid's website where they are not subject to confidentiality requirements agreed to with specific customers.

The original text referred to by the AER in Section 12.1 at the top of page 19 has been re–expressed for additional clarity, as follows (page 19):

> Under the proposed pricing methodology the locational charges to be recovered monthly from each customer will be determined for invoicing purposes by:
>
> 1. Multiplying the maximum demand rate determined for each connection point with the customer in question by the maximum half hourly average demand to occur at that connection point in that month.
>
> 2. Summating the results of Step 1 for each connection point with the customer in question.

TransGrid also updated its revised proposed pricing methodology with the relevant wording included above.

Clause 6A.23.4(e) of the NER states:

> Prices for recovering the locational component of providing prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated.

The AER notes that TransGrid's proposed locational pricing structure uses maximum monthly demand data from the previous financial year, with adjustment for forecast system load growth, to calculate its locational price. The AER also notes that transmission network investment is likely to be contemplated in response to peaks in demand.

TransGrid has not proposed a locational pricing structure included in the guidelines, however, the guidelines provide scope for a TNSP to propose alternative locational pricing structures provided they:

- are consistent with the pricing principles outlined in the NER
- improve on the permitted pricing structures outlined in the guidelines
- contribute to the NEM objective (now the national electricity objective).

TransGrid's proposed locational pricing structure captures peaks in monthly demand and is therefore consistent with the pricing principles in the NER (including clause 6A.23.4(e)). Its locational pricing structure is relatively simple to apply, includes an adjustment for forecast demand in the next financial year and is at least on par with the two pricing structures provided in the guidelines.

The locational price is intended to reflect the cost of shared transmission assets used to deliver electricity to consumers. A locational pricing structure based on peak monthly demand is likely to promote efficient use of electricity services for the long–term use of consumers by ensuring that those that cause high demand, and therefore transmission network augmentation, pay for the impact of that high demand.

12.4.3 Points in the network where prices and charges are determined

AER draft decision

In response to a submission from the Energy Markets Reform Group (EMRF),[487] the AER recommended that it may be beneficial for TransGrid to specify the points in the transmission network where costs would be allocated and prices determined. It noted that TransGrid was not required to include these details under the NER or the guidelines.

Revised revenue proposal

In its revised revenue proposal, TransGrid stated that it did not accept the AER's suggestion to include a list of connection points in the pricing methodology. It stated the locations where transmission prices are determined are published on TransGrid's website each year and to include these locations in its revised proposed pricing methodology would create an additional administrative burden for the AER and TransGrid whenever there was a change to the billable connection points.[488]

AER considerations

In making the recommendation that TransGrid specify the points in the network where costs are allocated and prices determined, the AER did not intend that TransGrid should list its connection points. Rather, the AER considered TransGrid's pricing methodology would be improved by clarifying that prices would be calculated at transmission connection points as it indicated in its revised revenue proposal.

The AER accepts that under the NER and the guidelines, TransGrid is not required to include these details in its revised proposed pricing methodology.

12.5 AER determination

The AER has considered TransGrid's amended proposed pricing methodology, as submitted on 2 February 2009, and is satisfied that it complies with the NER and the guidelines. The approved pricing methodology is included in part 4 of the transmission determination for TransGrid.

487 EMRF, *A response by the EMRF*, August 2008, p. 30.
488 TransGrid, *Revised revenue proposal*, p. 104.

Glossary

AASB	Australian Accounting Standards Board
ABS	Australian Bureau of Statistics
ACG	Allen Consulting Group
ANZSIC	Australian and New Zealand standard industrial classification
AUD	Australian dollar
bppa	basis points per annum
CAM	cost allocation method
CAPM	capital asset pricing model
CEG	Competition Economists Group
CFC	Construction Forecasting Council
CGS	Commonwealth government securities
CIE	Centre for International Economics
CPRS	Carbon Pollution Reduction Scheme
CRNP	cost reflective network pricing
DMPP	demand management and planning project
DRP	dividend reinvestment plan
EBSS	efficiency benefit sharing scheme
ECFM	Efficiency carry forward mechanism
EGW	electricity, gas and water
EMA	Emergency Management Australia
EMRF	Energy Markets Reform Forum
ESCV	Essential Services Commission of Victoria
EUAA	Energy Users Association of Australia
GIS	gas insulated switchgear
HRC	hot rolled coil
IAA	Institute of Actuaries of Australia
JIA	Joint Industry Association
kV	kilo volt
LCM	labour cost model
LME	London Metal Exchange
market impact component	market impact of transmission congestion component
MITC	market impact of transmission congestion
MM2	Econtech, Murphy Model II
MMA	McLennan Magasanik Associates
MRP	market risk premium

MVA	mega volt amperes
MVAr	mega var, mega volt amperes reactive, (one thousand kilovolt amperes reactive)
MW	megawatt
NPV	net present value
NSP	network service provider
NSW DNSPs	Country Energy, EnergyAustralia and Integral Energy
NTSC	negotiated transmission service criteria
NYMEX	New York Mercantile Exchange
POE	probability of exceedence
PTRM	post–tax revenue model
QNI	Queensland NSW interconnector
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RFM	roll forward model
SAHA	SAHA International Limited
SEO	seasoned equity offer
SFG	Strategic Finance Group Consulting
SKM	Sinclair Knight Merz Pty Ltd
SRP	*Statement of principles for the regulation of electricity transmission revenues*, 8 December 2004
the scheme	the service target performance incentive scheme
STPIS	service target performance incentive scheme
the Award	TransGrid enterprise bargaining agreement
transitional chapter 6 rules	transitional provisions set out in appendix 1 of the NER
TUOS	transmission use of system
Ofgem	Office of Gas and Electricity Markets – UK regulator
USD	United States dollar
WACC	weighted average cost of capital
YTM	yield to maturity

Appendix A: Cost escalators

This appendix presents the AER's final assessment of the methodology and data sources for proposed cost escalators. The values of these escalators have been updated to reflect the latest available information.

Introduction

In recent decisions for electricity TNSPs (including Powerlink, SP AusNet and ElectraNet),[489] the AER has allowed capex and/or opex allowances to be escalated in real terms for input cost increases. This involves the disaggregation of expenditure allowances into specific inputs (e.g. labour, land and materials), which are priced in terms of a base year. These base year costs are increased or decreased for each year of the regulatory control period relative to changes in the nominal price level, which is taken into account when prices and revenues are adjusted at the aggregated level under the CPI–X control mechanism.

The methodology employed to determine the cost escalators generally combines independent forecast movements in the price of input components with 'weightings' for the relative contribution of each of the components to final equipment/project costs. This in turn generates real capex and opex forecasts for the regulatory control period. The weightings are typically specific to each regulated business given differences in composition of their respective expenditure forecasts.

The underlying objective of real cost escalations was to take account of the commodities boom and skills shortages in the engineering field in Australia. In light of these external factors, it was considered that cost escalation at CPI no longer reasonably reflected a realistic expectation of the movement in some of the equipment and labour costs faced by electricity network service providers (NSPs).[490] It was also communicated by the AER at the time of allowing real cost escalations that the regime should symmetrically allow for real cost decreases.[491] This was to allow end users to receive the benefit of real cost reductions as well as facing the cost of real increases.

Given that there is no futures market for the procurement and installation of electrical equipment (e.g. transformers, switchgear), in previous decisions cost escalations have been estimated with reference to the expected growth in key input 'cost factors' such as:

- copper
- aluminium
- crude oil
- construction costs
- electricity, gas and water (EGW) sector labour costs
- land/easement costs.

---

489 AER, *Decision, Powerlink 2007–08 to 2011–12*, pp. 60–70; AER, *Draft decision, SP AusNet 2008–09 to 2013–14*, pp. 87–91, 316–331 and *AER, Final decision, ElectraNet 2008–09 to 2012–13*, pp. 29–48.

490 NER, clause 6A.6.7(c)(3).

491 AER, *Final decision, SP AusNet 2008–09 to 2013–14*, January 2008, p. 80.

Other inputs (such as steel) were escalated at CPI.

AER draft decision

In assessing the escalators recommended by the Competition Economists Group (CEG) and used by TransGrid, the AER considered that its conclusions from the recent ElectraNet decision were still applicable with respect to the methodology used for estimating each of the cost escalators (i.e. copper, aluminium and crude oil). In most cases, it considered that CEG had not presented any new compelling evidence that justified a departure from the approach previously accepted.[492]

At a fundamental level, the AER was concerned with the additional cost factors—producer margins and indirect producer labour— that did not meet the underlying objective for inclusion in forecast costs under clause 6A.6.7(c) of the NER.[493]

In particular, the AER considered that given the inherent uncertainties around the existence of and estimation of real movements in these cost factors, departures from CPI escalation were not warranted. It also noted that it accepted that such costs were likely to be included in base (unit) cost estimates but questioned the extent to which real growth was expected and whether they could be forecast on a reasonable basis.[494]

In the draft decision, the AER also stated that it would update its escalators closer to the time of the release of its final decision.[495]

Revised revenue proposal

TransGrid did not accept the materials cost escalators applied by the AER in the draft decision. It re–engaged CEG to review the draft decision.[496] CEG determined that while the AER's approach was largely reasonable, it was concerned with:[497]

- technical aspects of the AER's modelling, principally timing and the application of lags
- the AER's proposed approach to updating labour cost escalation factors.

TransGrid accepted the the cost escalator for land but proposed revised escalators for the majority of the other escalators.

---

492 AER, *Draft decision*, p. 68.
493 AER, *Draft decision*, p. 68.
494 AER, *Draft decision*, p. 68.
495 AER, *Draft decision*, p. 69.
496 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009.
497 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 2.

Non–labour cost escalators—aluminium, copper, steel and crude oil

AER draft decision

Taking into account the methodology it had developed for the ElectraNet decision,[498] the AER rejected TransGrid's materials cost escalators.[499] It applied the materials cost escalator set out in table A.1 for the next regulatory control period.

Table A.1: AER draft decision on real aluminium, copper, crude oil and steel cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–6.3	–7.0	7.5	9.3	–0.8	–1.3	–1.6
Copper	–6.3	–13.5	0.3	1.4	–5.6	–6.3	–7.0
Steel	53.8	–3.7	0.6	–3.4	–2.5	–3.0	–3.4
Crude oil	43.5	–13.4	1.5	1.7	0.1	–0.6	–0.1

Source: AER, *Draft decision*, p. 69.

The AER forecast aluminium and copper prices by using the London Metal Exchange (LME) futures prices up to 2010 and then long–term Consensus Economics forecast (7.5 years). It interpolated between the two data sources to obtain a data series that covered the next regulatory control period. Since all aluminium and copper prices from LME and Consensus Economics were in nominal US dollar (USD) terms, the projections were also converted into nominal Australian dollars (AUD)[500] (see section: *Exchange rates* of this appendix).

The AER used hot rolled coiled steel prices from Bloomberg for historical steel prices from Europe and the United States and then Consensus Economics forecasts for corresponding future prices. These steel prices were then:[501]

- adjusted from short to metric tonnes for US steel prices
- averaged and adjusted to Australian dollar terms using a methodology consistent with that adopted for aluminium and copper prices.

The AER forecast the real cost escalation for oil using historical average world oil prices sourced from the US Department of Energy and Bloomberg forecast contract prices. The prices were then averaged and adjusted to Australian dollar terms using a methodology consistent with that adopted for aluminium and copper prices. Due to the high volatility of the data, it used a centred moving average to account for prices for each month.[502]

498 AER, *Final decision, ElectraNet transmission determination 2008–09 to 2012–13.*
499 AER, *Draft decision*, p. 69.
500 AER, *Draft decision*, pp. 260–263.
501 AER, *Draft decision*, p. 266.
502 AER, *Draft decision*, pp. 268–269.

The AER also considered that it was not appropriate to apply a lag to commodity input prices in the process of escalating the materials component of capex.[503]

Revised revenue proposal

TransGrid did not accept the materials cost escalators applied by the AER in the draft decision. It re–engaged CEG to review the draft decision and CEG found that while the AER's approach was reasonable, issues surrounding the base period and lag adjustment had not been appropriately considered.[504]

CEG stated that the AER's decision to use June on June escalation factors for materials assumed that all objects were costed and purchased in June rather than spread over the 12 months of a financial year. It suggested that base period prices should be escalated to reflect the change in average prices from the base period to the 12 months to June of each future year.[505]

TransGrid accepted CEG's findings and proposed revised real cost escalators for materials as set out in table A.2.

Table A.2: TransGrid revised real aluminium, copper, steel and crude oil cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–15.9	5.3	7.6	6.6	3.5	–0.8	–1.1
Copper	–6.7	–14.8	–4.1	7.1	5.6	–6.0	–6.4
Steel	5.8	42.9	–8.2	2.1	–3.8	–4.7	–5.0
Crude Oil	29.4	–0.2	0.9	6.8	2.9	0.3	–1.0

Source: CEG, *Escalators affecting expenditure forecasts*, p. 24.

Submissions

The Energy Users Association of Australia (EUAA) noted a changed economic outlook and falls in materials costs both domestically and globally. It welcomed the AER's decision to review input costs prior to the final decision.[506]

Origin Energy, in a submission to the AER on the NSW DNSP draft decision, noted that the concerns it raised in its submission equally applied to TransGrid. Specifically, it noted the economic outlook had changed considerably and that economic data was pointing to reduced materials costs.[507]

503 AER, *Draft decision*, pp. 259–270.
504 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, pp. 3–7, 17–19.
505 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, pp. 3–6.
506 EUAA, pp. 12–13.
507 Origin Energy, p. 5.

AER considerations

Base period adjustment

The AER considers that CEG's recommendation to adopt a 12 month averaging period for materials escalators for each financial year of the next regulatory control period is reasonable.[508] It considers this is appropriate as it:

- removes potential price distortions that may occur during any single month
- recognises that all equipment is not costed and purchased over a single month but over each financial year of the period.

The AER also considers that this approach will permit the development of a robust forecast that reflects all materials cost data for each year.

The AER also considers there is merit in making an adjustment to reflect base period prices, as this allows for more accurate cost escalation to be determined. For TransGrid, this period is the financial year 2006–07. The AER has therefore adjusted the base period for TransGrid to reflect the base cost period of financial year 2006–07 for each financial year of the next regulatory control period.

Adjustment lag

In its revenue proposal, TransGrid used the cost escalators calculated for it by CEG. The AER notes that while CEG recommended that these escalators be lagged by six to 12 months, TransGrid did not incorporate that recommendation in its proposed escalators.

In the material provided to support TransGrid's revised revenue proposal, the AER notes that TransGrid's approach to applying lags appears to have changed. Specifically, the cost escalators calculated for, and accepted by, TransGrid assumed a lag of six months for copper, aluminium, steel and oil.[509]

The AER notes that TransGrid's adoption of CEG's updated methodology represents a fundamental shift in the methodology put forward and accepted in the draft decision. It also notes that TransGrid has 'recognised and acknowledged that there is an inherent six month lag applied as a result of the CEG data'.[510]

Under clause 6A.12.3(b) of the NER, a TNSP may only make revisions to its revenue proposal so as to incorporate the substance of any changes required by, or to address matters raised in, the draft decision (see also 6A.14.3(h)(3)(ii)).

The AER considers that the methodology adopted by TransGrid in its revised revenue proposal differs from that contained in its revenue proposal and that this change was not made to address matters raised in the draft decision. Therefore, the AER need not consider it. The AER has, however, considered the use of lags and considers that TransGrid has not provided any new evidence in its revised revenue proposal to support the suggestion that movement of commodity prices systematically flows through to final

508 This averaging period is centered on December as proposed by CEG as it is reflective of price movements over the entire year.

509 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 19.

510 TransGrid, *Response to information request number 325*, 27 February 2009.

goods prices. In addition, no evidence has been provided to demonstrate the potential impact of other factors, such as other cost inputs and economic conditions, on electrical equipment prices. As a result, the AER has not included lags in the final decision.

Other issues

The AER identified an error in the draft decision model for the calculation of cost escalators for copper and aluminium. In the draft decision, the AER stated that the forecast monthly copper and aluminium prices were determined by interpolating between the LME spot price, the three month LME contract price, the 15 month LME contract price, the 27 month LME contract price and the most recent long–term Consensus Economics forecast price. This process was not, however, correctly reflected in the model and this has been addressed for this final decision.

The AER also identified that with TransGrid having accepted CEG's use of a centred moving average for each series that it should have used the escalators detailed under the 'December to December' table in CEG's second report when determining its capex allowance. The 'December to December' escalators submitted with TransGrid's revised revenue proposal are comparable to the 'June to June' escalators applied in the draft decision. The AER considers using those escalators will result in escalators that are representative of the costs that a reasonable TNSP will incur. The AER engaged with TransGrid on this issue and obtained agreement about which escalators should be applied in its modelling.

The AER's conclusion on materials cost escalations is set out in table A.3.

Table A.3: AER conclusion on TransGrid's real aluminium, copper, steel and crude oil cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–16.13	–17.34	–14.06	9.13	10.55	10.93	9.32
Copper	–6.93	–27.93	–10.83	2.06	2.46	2.32	1.96
Steel	5.57	16.27	–15.32	7.21	5.25	1.03	0.76
Crude oil	28.58	–18.33	–5.19	10.24	5.74	2.16	1.30

Electricity, gas and water wages

AER draft decision

In the draft decision, the AER engaged Econtech to provide advice on labour cost growth forecasts in NSW. The AER was satisfied that Econtech's wage growth forecasts for the electricity, gas and water (EGW) sector were robust and applied these forecasts for the next regulatory control period. In applying Econtech's forecasts, the AER did not accept TransGrid's proposal, which was based on advice from CEG, to apply an average of Econtech (published in 2007) and Macromonitor EGW labour costs growth forecasts.[511]

[511] AER, *Draft decision*, p. 252.

The AER considered the averaging methodology adopted by CEG was not appropriate because the Macromonitor and Econtech EGW labour costs growth forecasts were not comparable and averaging the two forecasts was likely to produce unreliable labour cost escalation forecasts. In addition, the AER did not consider it appropriate to rely on the forecasts presented by Macromonitor because there was no description of the methodology used to forecast EGW wages or productivity adjustments for the AER to make an assessment.[512]

The AER accepted that Econtech's general labour cost growth forecasts were appropriate to escalate direct labour costs (i.e. other than EGW) incurred by TNSPs. The AER, however, did not accept the general wage forecasts applied by TransGrid, sourced from Econtech's 2007 report, due to the change in economic conditions that occurred since the report was released. The AER considered Econtech's latest general wage forecasts were more appropriate as they took account of more recent data, and were based on a more reliable forecasting methodology and robust data source.[513]

The AER's conclusions for TransGrid's EGW and general labour forecasts are set out in table A.4.

Table A.4: AER draft decision on TransGrid's EGW and general labour (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
EGW wages	0.1	2.8	3.9	3.4	3.0	2.8	2.1	1.0
General labour	0.6	1.0	1.1	0.7	0.7	0.8	0.6	0.8

Source: AER, *Draft decision*, pp. 253, 256.

Revised revenue proposal

TransGrid did not accept the EGW wages and general labour escalators applied by the AER in the draft decision. It re–engaged CEG to review the draft decision. CEG considered that while the AER's approach was largely reasonable, it had concerns with the timing calculations applied in the draft decision. Issues raised by CEG are discussed below.

AER analysis of the Macromonitor forecasts

CEG did not accept the AER's reasons for rejecting the Macromonitor labour cost forecasts proposed by TransGrid. CEG advised there were three Macromonitor reports which it relied upon, and considered that it had sufficiently described the basis on which Macromonitor derived the labour cost forecasts.[514] These reports include:

- *Forecasts of Cost Indicators for the Electricity Transmission Sector – New South Wales and Tasmania,* February 2008
- *Forecasts of Cost Indicators for the Electricity Transmission Sector – Forecasting Methodology,* September 2008

512 AER, *Draft decision*, p. 253.
513 AER, *Draft decision*, pp. 253–254.
514 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 27.

- *Australian Construction Outlook 2008,* November 2007.

CEG considered the only major difference between Macromonitor and Econtech's forecasts to be the application of Econtech's econometric model of the Australian economy to derive its forecast. CEG stated that econometric models did not provide superior forecasts and provided a number of quotes from academics to support this view.[515]

CEG stated Econtech has made clear it did not adjust its labour cost forecasts for productivity.[516] CEG also considered that the AER, in accepting Econtech's forecasts, has implicitly accepted that forecast wages growth should not be adjusted for productivity growth.

CEG did, however, acknowledge the professional expertise of Econtech and accepted the use of Econtech's forecasts in the draft decision as reasonable. CEG recommended TransGrid adopt the AER's forecasts in its revised revenue proposal.[517]

Application of EGW wage and general labour escalators

CEG raised issues with applying updated Econtech EGW and general labour escalators after TransGrid had lodged its revised revenue proposal. CEG stated that in the case of wage forecasts, there is a degree of judgement involved in assessing the variables that make up labour cost forecasts. CEG considered that if the AER was to seek an update from Econtech for EGW labour cost growth rates, it would be re–doing a forecast, rather than updating a forecast in accordance with an agreed methodology. CEG stated that the AER should consult with the NSPs if further updates were recommended by Econtech.[518]

Timing

CEG raised a number of concerns with the timing calculations applied in the draft decision. Specifically:[519]

- Econtech's forecasts for EGW and general wages growth were in financial year average terms, and not in June to June terms
- Award rates were not correctly timed to interpolate to EGW rates, resulting in the model double counting inflation for some years.

As a result, CEG proposed revised EGW wages and general labour escalators, based on the Econtech forecasts applied by the AER in its draft decision, to address these concerns.

Submissions

The EUAA submitted:[520]

515 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, pp. 28–29.
516 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 33.
517 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 13.
518 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 13.
519 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, pp. 7–12.

- that the AER should refresh its labour cost escalation assumptions in light of the recent economic collapse and global downturn
- expected real wage increases should ultimately be discounted for normal increases in labour productivity
- that the past commodity boom and labour shortages were no longer realistic assumptions for the next regulatory control period
- cost escalation factors and labour costs be reviewed and updated for the changed economic circumstances that have resulted in the 12 months since TransGrid's capex planning assumptions were developed.

Consultant review

The AER re–engaged Econtech to provide an update on its wage forecasts for the EGW sectors in NSW, ACT, Tasmania and nationally.[521] Econtech's EGW labour cost growth rates for NSW and Australia shown in table A.5.

Table A.5: Econtech's real labour escalation rates for the EGW sector in NSW and Australia (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	1.3	–0.7	3.3	3.6	2.4	1.7	0.6
Australia	–0.7	–1.0	2.8	3.1	2.1	1.5	0.5

Source: Econtech, *Updated labour cost growth forecasts*, pp. 28, 31.

Econtech determined these forecasts using an updated version of its labour cost model (LCM).[522] In particular, the forecasts provided by Econtech reflect the following factors:[523]

- an enhanced approach to labour cost forecasting, which was initially used in the September 2008 report
- national accounts data up to December 2008 (published by the Australian Bureau of Statistics (ABS))
- average weekly earnings data up to November 2008 (obtained by request from the ABS)
- the federal government stimulus package announced in December 2008 and February 2009.

Econtech noted the revisions to the ABS average weekly earnings data series for the August 1996 to May 2008 period, as a result of the ABS quantifying the extent of mis–reporting with data providers.[524]

520 EUAA, pp. 13 and 17.
521 Econtech, *Updated labour cost growth forecasts*.
522 This model was purpose built by Econtech for its report to the AER in August 2007.
523 Econtech, *Updated labour cost growth forecasts*, p. 4.
524 ABS, *Cat. No. 6302.0.553.001, Information paper: revisions to average weekly earnings series*, August 2008.

Econtech acknowledged that its updated labour cost growth forecasts differ considerably to its labour forecasts, published in September 2008. Econtech linked the immediate slowing of labour cost growth projections with the deteriorating global financial situation and anticipated that Australia will slip into recession in 2009. Econtech further noted deteriorating consumer and business confidence, declining dwelling investment, credit markets remaining frozen and expected increases in unemployment rates as contributing factors to Australia's forecast declining economic performance.[525]

Econtech considered that the updated short to medium–term labour growth forecasts will vary the most compared with previous projections in September 2008, as a result of the global financial crisis and downward revisions to business investment during 2008–09 to 2010–11. Econtech further considered that the longer term labour growth projections are largely unaffected as it anticipated that Australia will begin to recover from the recession in late 2010.[526]

Econtech observed that the recent crash in commodity prices has had implications for labour demand in the mining industry and consequently, wages growth in that sector. Specifically, this has had a flow on effect for EGW labour forecasts, where competition for workers with similar skills—namely, electricians and electrical and other engineers from the mining and construction industries—has slowed.[527] This slowing in labour demand has resulted in slowing wage growth in the EGW sector, which has fallen (compared to Econtech's September 2008 forecasts) particularly in the immediate period to 2009–10.[528] This is consistent with the inverse observations by Econtech relating to increases in above average wages growth, due to the recent mining and construction boom, which were exacerbated by a skills shortage and businesses being forced to offer higher wages to attract skilled workers.[529]

At the national level, Econtech considered that the projected growth rate for the EGW sector is expected to perform better relative to the mining and construction industries. This outcome is consistent with Econtech's observations in its September 2008 report, where it noted that given the essential nature of utility services, the EGW sector has a greater imperative to attract and maintain skilled workers.[530]

Econtech made the following observations on the utility sector in NSW:[531]

- the current economic slowdown would particularly affect NSW, given its financial dominance in Australia
- state economic performance is expected to mirror the performance of Australia as a whole
- the slowing wages growth across all sectors/industries is expected to occur in 2008–09 to 2010–11, given general economic conditions have shown the sharpest deterioration in this period

525 Econtech, *Updated labour cost growth forecasts*, pp. 7–8.
526 Econtech, *Updated labour cost growth forecasts*, pp. 8–9.
527 Econtech, *Updated labour cost growth forecasts*, p. 9.
528 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008, p. 25.
529 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, p. 23.
530 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, p. 23; and Econtech, *Updated labour* cost growth *forecasts*, p. 9.
531 Econtech, *Updated labour cost growth forecasts*, pp. 11–12.

- EGW wages, despite having eased in the immediate forecast period, still remain above the national EGW average, which aligns with historical trends
- the forecast EGW average annual real growth rate (at 2.7 per cent) is expected to be higher than the all–industry average (at 1.0 per cent) for the next regulatory control period.

As part of its updated EGW forecasts, Econtech also provided an update on general wage forecasts for all industries for NSW.[532] Econtech's updated general labour cost growth rates are shown in table A.6.

Table A.6: Econtech's real general labour escalation rates for NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	0.9	–1.6	0.7	1.3	0.4	0.1	–0.6

Source: Econtech, *Updated labour cost growth forecasts*, p. 28.

As part of updating its forecasts, Econtech also undertook a review of CEG's report submitted in January 2009, which formed part of TransGrid's revised revenue proposal.[533]

AER considerations

Econtech and Macromonitor forecasts

In the draft decision, the AER reviewed the three Macromonitor reports referred to by CEG. The AER maintains its view that it is not satisfied that they provide sufficient explanation surrounding the basis of the model used to derive Macromonitor's forecasts. The AER notes Macromonitor's discussion of the drivers of unit costs but also notes Macromonitor did not outline any determining factors or key macro–economic variables that it employed to calculate its EGW labour cost growth forecasts.[534] The AER maintains that the Macromonitor reports do not contain sufficient description of the methodology used to forecast wage growth.

The AER notes that Econtech's September 2008 report considered the Macromonitor report did not contain any description of the methodology used to forecast wages growth. Econtech considered that the extent to which Macromonitor's forecasts for EGW wages are consistent with the outlook for broad macro–economic factors nationally, and across industries and states is unclear.[535] Econtech found that upon reviewing CEG's revised escalator report, it remains difficult to assess the forecast results provided by Macromonitor as no new information pertaining to the methodology has been provided.[536]

The AER is satisfied that Econtech's methodology for forecasting labour costs growth is robust given the application of both an economic–wide model (Murphy model II (MM2))

532 Econtech, *Updated labour cost growth forecasts*, p. 28.
533 Econtech, *Updated labour cost growth forecasts*.
534 Macromonitor, *Forecasts of Cost Indicators for the Electricity Transmission Sector – New South Wales and Tasmania*, p. 3.
535 Econtech, *Labour Cost Growth Forecasts 2007/08 to 2016/17*, p. 39.
536 Econtech, *Updated labour cost growth forecasts*, p. 21.

and a purpose–built LCM.[537] Econtech provided, in its report, additional information pertaining to its LCM and MM2 methodology and also advised further information and assumptions are publicly available.[538]

The AER sought a list of exogenous variables, and assumptions, employed by Econtech to produce its labour forecasts.[539] Further, the AER considers these forecasts to be adequately substantiated by Econtech's analysis across states and industries, and is consistent with national data and reflective of Econtech's national outlook based on the current economic climate.[540] The AER is satisfied that Econtech's modelling is transparent and appropriately reflects current economic conditions to produce reliable forecasts.

The AER notes Econtech's response to CEG's concerns regarding Econtech updating its labour forecasts.[541] Econtech stated the procedure used in updating the forecasts does not alter its methodology. Further, the structure of both the MM2 and LCM will remain the same as those applied in its September 2008 labour cost forecasts. Econtech also advised judgemental adjustments are applied in a systematic fashion designed to capture key economic information not contained in historical data. The AER is satisfied that Econtech has updated its forecasts, consistent with the process accepted in the draft decision, to produce robust labour growth forecasts to apply for the next regulatory control period.

The AER agrees with CEG's view that productivity adjustment can be an important factor in forecasting actual business costs.[542] Further, the AER notes that Econtech's forecasts are adjusted for productivity growth. Unlike the Macromonitor forecasts, Econtech's forecasts of wages growth do not remove productivity growth. Rather Econtech's forecasts of wage growth represent the general increases in wages (above CPI) as well as specific compensation to labour for increases in productivity. The AER notes Econtech's labour productivity assumptions are incorporated in its MM2 model through its labour productivity index. Further, MM2 incorporates assumptions regarding the growth in labour efficiency for each industry, enabling separate labour productivity assumptions for each 1–digit ANZSIC.[543] The AER is therefore satisfied with the approach and methodology applied by Econtech to incorporate productivity in its wage growth forecasts.[544]

The AER also notes CEG's acknowledgment of Econtech as a reputable forecaster and that Econtech's forecasts have the advantages of being more recently developed, as they were based on more recent data. The AER further acknowledges CEG's comments that it is for these reasons that CEG accepted the use of the Econtech EGW wages and general labour forecasts applied by the AER in its draft determination as reasonable and has

537 Econtech, Labour Cost Growth Forecasts 2007/08 to 2016/17.
538 Econtech, *Updated labour cost growth forecasts*, 25 March 2009.
539 Econtech, *Updated labour cost growth forecasts*, 25 March 2009, p. 25.
540 The AER and CEG have previously applied Econtech's national forecasts in the SP AusNet and VENCorp revenue resets. See AER, *Draft decision*, p. 250.
541 Econtech, *Updated labour cost growth forecasts*, pp. 20–26.
542 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 33.
543 ANZSIC refers to the Australian New Zealand Standard Industrial Classification. See Econtech, *Updated labour cost growth forecasts*, p. 24.
544 Econtech, Labour Cost Growth Forecasts 2007/08 to 2016/17, pp. 41–42.

recommended the businesses adopt the Econtech forecasts in their revised regulatory proposals.[545]

Updated labour cost escalators

In the draft decision, the AER applied Econtech's general wage growth forecasts for all industries across Australia to escalate direct labour costs incurred by TransGrid.[546] However, the AER notes the application of Econtech's EGW labour growth forecasts, which are based on state/territory specific data, and Econtech's general labour growth forecasts, which are based on national data, are inconsistent. The AER is of the view that NSW specific general labour escalators should be applied to TransGrid's general wages, as it reflects the economic circumstances and performance of NSW and is likely to be a better predictor of future trends in wages growth in NSW. Therefore, for this final decision the AER will apply Econtech's all industries wage growth forecast for NSW as TransGrid's general labour escalator.

For this final decision, the AER has adopted actual wage data increases for 2007–08 provided for under TransGrid's Award. Further, the AER has applied TransGrid's 2008–09 Award rates to its EGW labour escalation. For the next regulatory control period the AER has adopted Econtech's updated the EGW labour cost escalators.

CEG has stated that the AER has indicated it would use future Award labour costs where these are available.[547] To clarify, the AER is using the Award rates, in the current regulatory control period to escalate labour costs from the base period (2006–07) to the end of the current regulatory control period. However, for the next regulatory control period the AER will adopt Econtech's updated EGW labour cost growth forecasts. The AER does not consider it appropriate to use TransGrid's Award rates for the next regulatory control period as this would move TransGrid from an incentive based framework to a cost of service recovery framework. This means TransGrid still has an incentive to negotiate with its employees to obtain productivity savings under its Award.

The AER considers that CEG's recommendations regarding the appropriate timing of the escalators the AER applied in the draft decision are generally reasonable. The AER has implemented CEG's recommendations to EGW and general labour by making refinements to its cost escalations model to ensure:

- inflation was correctly accounted for by only using real wage rates for both Award rates and EGW rates
- the Award rates are appropriately timed with EGW rates. As recommended by CEG the AER has addressed this by creating a quarterly index of real wage rates.

The AER notes that CEG converted Econtech's annualised EGW wage rates into quarterly rates using compounding formulae, however, this appears to cause a distortion of the annual wage rate. Econtech has recommended the AER adopt its approach of using a quarterly disaggregation formula which results in the same annual wage rate.[548] The

545 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 13.

546 AER, *Draft decision*, p. 255.

547 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 8.

548 Econtech, *Updated labour cost growth forecasts*, pp. 23–24.

AER has adopted Econtech's methodology for creating a quarterly EGW wage rate as it does not distort the annual wage rate.

The AER considered CEG's application of compounding formulae when converting the yearly Award wage rates to quarterly terms to be inappropriate as the increase in wage rates in reality are experienced from a single day. Therefore, CEG's approach can move escalations inappropriately between periods using the index approach as it smears the wage rate change over a year instead of being a single yearly adjustment. The AER has applied the whole Award rate increase in the first quarter of the calendar year that corresponds to TransGrid's Award wage rate increase date. This approach maintains CEG's application of the Award rates in quarterly terms but applies the whole wage increase in the first quarter instead of over the year.

The AER has identified an error in CEG's model which mistimes the application of Econtech's EGW wage rates by applying a financial year's data to a calendar year—this effectively means CEG has been using Econtech's labour rates six months before the period where they should be applied. The AER has corrected this error as part of the adjustments made for the appropriate timing of escalators in its model.

The AER notes that TransGrid, based on advice received from CEG, accepted the use of Econtech's forecasts in the draft decision as reasonable, subject to the AER rectifying the specified timing issues.[549] The AER further notes TransGrid's concerns with Econtech updating its forecasts after its revised revenue proposal had been submitted. To ensure a robust and transparent process on updating of labour wage growth forecasts, the AER engaged in a briefing with TransGrid, where Econtech provided an overview of its economic models used to derive the labour wage growth forecasts and the economic assumptions underlying its updated forecasts. The AER also outlined refinements to its cost escalations model from the draft decision.

The AER also notes the submissions relating to labour cost escalators discussed changing economic conditions and the relevance of the labour cost escalators applied in the draft decision. Econtech was engaged by the AER to provide updated labour cost escalators based on most recent available data.[550] The AER considers the updated forecasts take account of the current economic slowdown.

AER conclusion

For this final decision, the AER has adopted Econtech's updated NSW EGW wage growth forecasts for the next regulatory control period. The AER has remodelled the forecasts to address CEG's timing issues and applied these updated forecasts for the EGW sector in NSW for the next regulatory control period. Actual wage data, however, was available for 2007–08 to 2008–09 and therefore, the AER has applied actual wage increases provided for under TransGrid's workplace awards for that year, which have also been remodelled to address the timing issues.

The AER's conclusion on the EGW labour cost growth forecasts to apply to TransGrid for the next regulatory control period is shown in table A.7.

549 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, pp. 7–12.

550 New forecasts incorporate data published by the Australian Bureau of Statistics, including Average Weekly Earnings (released 26 February 2009) and National Accounts (released 9 March 2009).

Table A.7: AER conclusion on TransGrid's real EGW labour growth rates (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Econtech/AER	1.69	0.84	3.27	3.60	2.40	1.70	0.60

For this final decision, the AER has also adopted Econtech's updated NSW general labour cost escalators for 2007–08 to 2013–14. The general labour cost growth forecasts the AER will apply to TransGrid's capex and opex for the next regulatory control period are set out in table A.8.

Table A.8: AER conclusion on TransGrid's real general labour escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Econtech/AER	0.90	–1.60	0.70	1.30	0.40	0.10	–0.60

As a result of the AER's analysis of the revised revenue proposal, the AER is satisfied that the application of the updated EGW and general labour cost escalators for NSW (as set out in tables A.7 and A.8), to TransGrid's capex and opex results in expenditure reasonably reflects the capex and opex criteria, including the capex and opex objectives. In coming to this view, the AER has had regard to the capex and opex factors.

Construction costs

AER draft decision

The AER, for the same reasons set out for EGW wages and general labour forecasts, rejected CEG's approach to averaging construction forecasts from Econtech and Macromonitor. In the draft decision, the AER applied construction cost forecasts sourced from the Construction Forecasting Council (CFC) website[551], which it deflated by CPI[552], to obtain real numbers.

The AER's draft conclusions for construction cost forecasts are set out in table A.9.

Table A.9: AER draft decision on TransGrid's real construction cost forecasts (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Construction costs	–0.3	–1.9	0.4	1.2	1.1	1.0	1.0

Source: AER, *Draft decision*, p. 276.

551 Construction Forecasting Council, website http://www.cfc.acif.com.au/.

552 The CPI figures used to deflate the construction cost forecasts were sourced from: Econtech, *Australian National State and Industry Outlook*, 22 July 2006.

Revised revenue proposal

TransGrid accepted the construction cost escalators applied by the AER in the draft decision, subject to the addressing of the timing issues raised by CEG.[553]

AER considerations

The AER, as per the discussion on EGW wages and general labour forecasts, applies the same approach to construction costs. It maintains the position it took in the draft decision to apply Econtech's construction cost forecast escalators. It does not consider it appropriate to rely on Macromonitor forecasts because there is no description of the methodology used to forecast growth for the AER to make an assessment.

The AER also considers that CEG's recommendation to use an index approach to determining the construction cost escalator is reasonable. Specifically, when used in conjunction with Econtech's yearly to quarterly conversion adjustment, it enables the appropriate base periods to be factored into the calculation of this escalator. This issue is discussed in more detail in the EGW and general labour section of this appendix.

AER conclusion

The AER notes TransGrid[554] accepts the application of its construction cost forecasts, subject to the AER reconciling the timing issues raised by CEG.[555] The AER has adjusted its modelling to reflect the approach taken by TransGrid in its revised revenue proposal.

The AER has applied updated CFC construction cost forecasts to TransGrid's capex proposals, received by the CFC on 6 April 2009. It has deflated these construction costs with updated inflation forecasts to provide real forecasts.[556]

The AER's conclusions on forecast construction cost escalators are set out in table A.10.

Table A.10: AER conclusion on TransGrid's real construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Construction costs	2.75	–1.28	–1.64	1.00	0.65	–0.37	–2.22

Producer margin

AER draft decision

The AER rejected the producer's margin escalator proposed by TransGrid as it did not meet the underlying objective for inclusion in forecast costs under clause 6A.6.7(c) of the NER. Based on the information presented by TransGrid, the AER was not satisfied that

553 TransGrid, *Revised revenue proposal*, p. 36.
554 TransGrid, *Revised revenue proposal*, p. 36.
555 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, pp. 7–12.
556 Econtech, *Australian National State and Industry Outlook*, 23 January 2009.

the associated expenditure reasonably reflected a realistic expectation of cost inputs over the next regulatory control period.[557]

The AER also considered the addition of a producer's margin escalator would represent a movement beyond the AER's obligation to provide a reasonable opportunity to recover efficient costs and that is represented a level of compensation for costs that was inconsistent with the general incentive framework.[558]

The AER allocated the portion of costs assigned to this escalator to the 'other' escalation category, which was escalated by CPI.[559]

Revised revenue proposal

TransGrid accepted the draft decision on producer's margin. It submitted revised cost escalators which removed real cost escalation from this proposed component.[560]

AER considerations

The AER accepts TransGrid's revised revenue proposal to remove real cost escalation from the proposed producer's margin component of its forecast equipment purchase costs.

Indirect (producer's) labour

AER draft decision

The AER did not accept the producer labour cost escalator applied by TransGrid. It considered that this escalator did not meet the underlying objective for inclusion in forecast costs under clause 6A.6.7(c) of the NER. The AER was not satisfied that the expenditure associated with a real escalation of indirect labour costs was required to meet the capex objectives.[561]

The AER also considered that the introduction of a labour component in equipment costs was inappropriate as it:[562]

- represented a movement beyond the AER's obligation to provide regulated businesses a reasonable opportunity to recover efficient costs towards providing compensation for changes in input costs at a very fine level of detail
- was sufficient to monitor whether the cost of finished goods, as opposed to the component parts, needed to be escalated above or below CPI
- was not supported by robust data.

The AER further noted that some amount of producer's labour costs would be embedded in TransGrid's base cost estimates of equipment.[563]

557 AER, *Draft decision*, p. 275.
558 AER, *Draft decision*, p. 275.
559 AER, *Draft decision*, p. 275.
560 TransGrid, *Revised revenue proposal*, p. 38 and appendix E.
561 AER, *Draft decision*, p. 257.
562 AER, *Draft decision*, p. 257.
563 AER, *Draft decision*, p. 257.

Revised revenue proposal

TransGrid accepted the draft decision on indirect producer's labour. It submitted revised cost escalators which removed real cost escalation from this proposed component.[564]

AER considerations

The AER accepts TransGrid's revised revenue proposal to remove real cost escalation from the proposed indirect producer's labour component of its forecast equipment purchase costs.

Exchange rates

AER draft decision

The AER considered that an exchange rate forecast by Econtech at the time of the final decision would represent a realistic expectation of forecast exchange rates over the next regulatory control period. For the purposes of the draft decision, it used the exchange rates set out in table A.11.

Table A.11: AER draft decision on AUD/USD exchange rate forecasts

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AER draft decision	0.85	0.96	0.88	0.84	0.82	0.80	0.79

Source: AER, *Draft decision*, p. 272.

Revised revenue proposal

In its revised revenue proposal, TransGrid applied the cost escalators calculated by CEG. CEG, in its cost escalation model, assumed future exchange rates were equal to those forecast by Econtech in October 2008.[565] This represented the most recent forecasts available to CEG at the time it submitted its report to TransGrid.

AER considerations

Consistent with the draft decision, and TransGrid's revised revenue proposal, the AER has used the most recent available exchange rate forecasts from Econtech to calculate the cost escalators.[566] The exchange rates used are set out in table A.12.

Table A.12: AER conclusion on AUD/USD exchange rate forecasts

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AER's conclusion	0.85	0.96	0.67	0.65	0.63	0.62	0.62

564 TransGrid, *Revised revenue proposal*, p. 38 and Appendix E.
565 Econtech, *Australian National State and Industry Outlook*, October 2008.
566 Econtech, *Australian National State and Industry Outlook*, 23 January 2009, p. 110.

Other issues

Inflation

Revised revenue proposal

CEG largely agreed with the AER's application of inflation in its calculation of cost escalators in the draft decision. However, it suggested a more accurate approach was possible with respect to the handling of inflation prior to June 2009.[567]

AER considerations

The AER undertook a review of its calculation of inflation. The AER considers that the approach to handling inflation proposed by CEG is more accurate than the approach used by the AER in the draft decision, although the difference is relatively minor.

However, the AER also determined that the methodology could be further improved by using the most recent historical monthly inflation figures rather than using yearly inflation figures. The AER therefore amended its methodology to incorporate this change, which also removed the need to amend the calculation of historical inflation as proposed by CEG.[568]

Historical oil data

Revised revenue proposal

In its first and updated report, CEG used an all countries trade weighted spot price for historical oil prices in its modelling.

AER considerations

The AER considers that the most appropriate historical oil series to be used with the New York Mercantile Exchange (NYMEX) oil futures prices is the West Texas Intermediate data series.[569] It considers that for data consistency, the West Texas Intermediate historical series should be used as the NYMEX oil futures prices are for West Texas Intermediate oil. It has amended its approach to correct for this error.

Historical steel data

Revised revenue proposal

CEG proposed using historical carbon steel prices for Europe and the US to enable the use of one more year of historical data and the appropriate application of its proposed methodology.

AER considerations

The AER accepts that the methodology it applied in the draft decision to materials cost escalators could be improved (section: *Non labour cost escalators* of this appendix). It also accepts that TransGrid's proposed use of one year's worth of carbon steel historical

[567] CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 17.

[568] CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 17.

[569] US Energy Information Administration, viewed 18 February 2009, http://www.eia.doe.gov/.

data is appropriate, as this will facilitate the calculating of historical steel prices while maintaining the methodology that it has adopted.[570] It notes, however, that in future determinations (all other things remaining equal), there will be sufficient historic data available to permit the use of hot rolled coiled steel price data to fully determine hot rolled coiled steel escalations.

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the revised revenue proposal, the AER is not satisfied that the proposed cost input escalators reasonably reflects the capex criteria, including the capex objectives. In coming to this view it has had regard to the capex factors.

Table A.13 sets out the AER's conclusions on TransGrid's real escalators over the next regulatory control period.

Table A.13: AER conclusion on real cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–16.13	–17.34	–14.06	9.13	10.55	10.93	9.32
Copper	–6.93	–27.93	–10.83	2.06	2.46	2.32	1.96
Steel	5.57	16.27	–15.32	7.21	5.25	1.03	0.76
Crude oil	28.58	–18.33	–5.19	10.24	5.74	2.16	1.30
EGW wages	1.69	0.84	3.27	3.60	2.40	1.70	0.60
General wages	0.90	–1.60	0.70	1.30	0.40	0.10	–0.60
Construction costs	2.75	–1.28	–1.64	1.00	0.65	–0.37	–2.22

570 This methodology involves calculating the HRC steel prices using European and US steel price indices.

Appendix B: Contingent projects

This appendix sets out the driver(s), scope and trigger(s) for the ten contingent projects included in TransGrid's revised revenue proposal. Under clause 6A.8.2 of the NER, TransGrid must demonstrate that the relevant trigger event in relation to a contingent project has occurred before the AER will make an assessment of any adjustments to TransGrid's maximum allowed revenue (MAR). When a trigger event occurs, the scope of a contingent project must not include any projects (or associated project scope) contained in TransGrid's approved capex allowance.

If TransGrid makes a contingent project application, it is expected to comply with the procedures in clause 6A.8.2(b) of the NER, and develop feasible options and costs that address the need for the project. Generally, the AER expects TransGrid to provide supporting information with its contingent project application that includes:

- the final regulatory test assessment
- tender submissions
- contracts
- other investment appraisals.

The AER's decision on the driver(s), scope and trigger(s) for each of the contingent projects proposed by TransGrid in its revised revenue proposal is set out below.

Hunter Valley – Central Coast 500 kV line

The driver for this project is the possibility of power station development in the Hunter Valley area to help address the increased load in the Newcastle–Sydney–Wollongong load corridor.

The scope of the project involves the development of a double circuit 500 kV line between the Hunter Valley and Eraring and the installation of an additional 500/300 kV transformer at Kemps Creek substation. The indicative cost of this project is $300 million.

The triggers for this project are:

The receipt by TransGrid of an application to:

1. connect a new power station with a generating capacity in excess of 400 MW

   or

2. increase the generating capacity of an existing power station by more than 400 MW in relation to TransGrid's transmission network located in the north or west of NSW

   or

3. agreement with Powerlink concerning the proposed development of the Queensland network interconnection which enables the import capability into NSW to be increased by more than 400 MW

   or

4. the receipt by TransGrid of an application to connect a spot load in the Newcastle area exceeding 200 MW

   or

5. the receipt by TransGrid of an application to increase an existing spot load in the Newcastle area by more than 200 MW

and, in each case,

the relevant application or development causes a network limitation to arise on the 330 kV network between Liddell/Bayswater and Tomago/Newcastle.

Yass–Wagga 500 kV double circuit transmission line

The driver for this project is the possibility that TransGrid will not be able to meet the power transfer capability between the Yass area and Victoria and the Wagga area. This applies in two situations:

- high power flows towards the NSW west area and Victoria
- high import from Victoria and Snowy towards NSW.

The scope of this project involves developing a new double circuit 500 kV (operating at 330 kV) between Yass and Wagga largely on the route on the existing Yass–Wagga 132 kV line. The indicative cost of this project is $329 million.

The triggers for this project are:

1. a set of generators, with a combined output exceeding 200 MW, is committed for connection to the network in the following southern areas of the NSW system south of the Yass/Canberra area:
   - Wagga
   - Jindera
   - Buronga/Broken Hill area
   - Snowy area

   or

2. the Victorian export capability to Snowy and NSW is increased by 200 MW above the present capability

and (for either of these triggers),

the generation development or increased export capability causes a network limitation to arise on the system between Murray and Upper Tumut/Lower Tumut or between Upper Tumut/Lower Tumut and Yass/Canberra.

Bannaby–Yass reinforcement

The driver for this project is the possibility that TransGrid will be unable to transfer the required power from the south at Snowy or from Victoria due to line rating constraints.

The scope of this project involves the uprating of the Bannaby to Yass (No. 39) 330 kV line and the Marulan to Yass (No. 4 and No. 5) 330 kV lines to 100 degree Celsius design conductor clearance. The indicative cost of this project is $45 million.

The triggers for this project are:

1. a set of generators, with combined output exceeding 200 MW, is committed for connection to the network in the following southern areas of the NSW system south of the Bannaby/Marulan area:
   - Yass
   - Canberra
   - Wagga
   - Jindera
   - Buronga/Broken Hill area
   - Snowy area

   or

2. the Victorian export capability to Snowy and NSW is increased by 200 MW above the present capability.

and (for either of these triggers),

the generation development or increased export capability causes a network limitation to arise on the system between Yass and Bannaby.

New 500/330 kV substation at Richmond Vale

The drivers for this project are either major load development in the Newcastle area or generation development in the Newcastle area or upgrading of the Queensland NSW interconnector (QNI). In particular, the need for this project may arise if:

- a significant industrial load is required in the Newcastle area, such as an aluminium smelter, and there is a need to reinforce the 330 kV system supporting the Newcastle area
- the 330 kV supply to the Newcastle area needs supporting due to the 500 kV line development between the Hunter Valley and the coast.

The scope of this project involves the establishment of a 500 / 330 kV substation at Richmond Vale. The indicative cost of this project is $80 million.

The trigger for this project is two fold:

1. the environmental consent authority determines that a 500 kV transmission line between the Hunter Valley and Eraring must utilise the route of an existing 330 kV line that supplies the Newcastle area in order to be approved

   and

2. the power transfer on the remaining 330 kV transmission line between Liddell and Tomago/Newcastle exceeds the contingency rating of the line (1430 MVA) under 'n–1' conditions, either during the construction of the Hunter Valley–Eraring 500 kV line or following its completion.

CBD and inner metropolitan area supply

The driver for this project is continued growth in electricity demand in the Sydney CBD that necessitates the replacement of more than two out of the four 132 kV distribution network cables between Lane Cove and Dalley Street to allow EnergyAustralia to meet its reliability obligations to supply the Sydney CBD.

The scope of this project involves the advancement of the next 330 kV cable to the CBD which is dependent on EnergyAustralia determining that the condition of the cables has deteriorated more rapidly than predicted and as a result, more than two of the four cables have to be removed from service prior to November 2017. The indicative cost of this project is $342 million.

The triggers for this project are the receipt by TransGrid of a written notification from EnergyAustralia that states:

1. it is proposing to retire more than two of the four 132 kV cables (cables 929 or 919/3, 92L/3, 92M/3 and 928/3), two or more years before the predicted November 2017 commissioning date of the next 330 kV cable to be constructed to the Sydney CBD by TransGrid
2. as a consequence, EnergyAustralia will be unable to meet its reliability of supply obligation to the Sydney CBD.

Gadara/Tumut load area

The driver for this project is the development of an industrial plant in the Tumut/Gadara areas that will increase maximum demand in excess of 20 MW. An increase in excess of this amount would overload the current 132 kV supply network and would breach TransGrid's reliability of supply obligations.

The scope of this project involves the construction of an additional 132 kV line from Wagga to either Gadara or Tumut, together with terminal works. The indicative cost of this project is $54 million.

The triggers for this project are:

1. the lodgement with TransGrid of a request to increase the agreed maximum demand for this industrial load by more than 20 MW

   and

2. acceptance by the operator of the industrial load of TransGrid's offer to connect via the execution of the related connection documentation.

Orange 330/132 kV substation

The drivers for this project is the confirmed expectation that the owner of an existing mine in the Orange will expand and would seek to increase the agreed maximum demand for the mine by more than 40 MW. An increase in excess of this amount would overload the current 132 kV supply network and would breach TransGrid's reliability of supply obligations.

The scope of this project involves:

- the construction of a single transformer 330 / 132 kV substation that is connected to TransGrid's Mt Piper to Wellington 330 kV line
- terminal works
- 330 kV and 132 kV line construction and rearrangement.

The indicative cost of this project is $47 million.

The triggers for this project are:

1. the lodgement with TransGrid or Country Energy of a request to increase the agreed maximum demand for the relevant mine by more than 40 MW

   and

2. acceptance by the operator of this mine of TransGrid's or Country Energy's offer to connect via the execution of the related connection documentation.

Reactive support and seven sites

The driver for this project is the need to ensure that the reactive power support required to maintain the power transfer capability from power stations to the main load centres in NSW is secured at the least cost to customers.

The scope of this project involves the installation of shunt capacitor banks at or near various power stations, totalling 1600 MVAr in eight banks. The indicative cost of this project is $36 million.

The triggers for this project are:

1. the sum total of offers from each generator for the provision of the network support services during the next regulatory control period exceeds the total cost of $36 million for installing eight 200 MVAr shunt capacitor banks, which are required to maintain the power transfer capability from power stations to the main NSW load centres and to meet TransGrid's related reliability obligations

   and

2. the determination (via the completion of the clause 5.6.6 process and the regulatory test) that the installation of shunt capacitor banks at or near power stations constitutes a least cost option for meeting TransGrid's specific reliability obligation in relation to the power transfer capability from a power station to the main NSW load centres (as compared to the option of acquiring network support services from that power station at the offered price).

QNI upgrade—line series compensation project

The driver for this project is the need to ensure that the capacity of the QNI is developed in a timely manner so that power transfer capability is optimised relative to transmission service costs. There is no one market development that will cause the current capacity to be considered insufficient. Rather, this requires ongoing assessment as regional demands and power sources evolve, using market simulation tools.

The scope of this project involves the augmentation of the power transfer capacity of QNI by the commissioning of series capacitors in transmission lines within the ownership of both TransGrid and Powerlink. The indicative cost to achieve a 150–200 MW increase in capacity is $120 million, of which $60 million will be incurred by TransGrid. The remainder will be managed by Powerlink. This balance of responsibility might change when cost and performance is optimised at the approvals stage.

The trigger for this project is:

1. the publication by the national transmission planner (or equivalent) of formal advice to the effect that augmentation of QNI to the extent of a capacity increment of 150 MW to 200 MW above the current capacity as determined by NEMMCO constraint equations, should be pursued within a timeframe that would require capex during the next regulatory control period

   or

2. if the introduction of the national transmission planner (or equivalent) is delayed, or if the national transmission planner (or equivalent) arrangements turn out to be different, TransGrid determines that augmentation of QNI, to the extent of a capacity increment of 150 MW to 200 MW above the current capacity as determined by NEMMCO constraint equations, should be pursued within a timeframe that would require capex in the next regulatory control period, including the successful completion of the regulatory test demonstrating that this project would deliver net market benefits.

Victorian interconnector development

The driver for this project is the need to ensure that the capacity of the interconnection between NSW and Victoria is developed in a timely manner, so that power transfer capability is optimised relative to transmission service costs. There is no one market development that will cause the current capacity to be considered insufficient. Rather this requires ongoing assessment as regional demands and power sources evolve, using market simulation tools.

The scope of this project involves:

- installation of series capacitor compensation in the Lower Tumut to Wagga and Wagga to Jindera 330 kV transmission lines
- uprating the Lower Tumut to Wagga transmission line by replacement of terminal equipment
- replacement of other equipment that has insufficient fault level capacity
- installation of a shunt capacitor bank.

The indicative cost of this project is $35 million.

The trigger for this project is:

1. the publication by the national transmission planner (or equivalent) of formal advice to the effect that augmentation of the NSW to Victoria interconnection to the extent of this capacity increment (approximately 180 MW above the current capacity of 1900 MW), should be pursued within a timeframe that would require capital expenditure in the next regulatory control period.

   or

2. if the introduction of the national transmission planner (or equivalent) is delayed, or if the national transmission planner (or equivalent) arrangements turn out to be different, TransGrid determines that augmentation of the NSW to Victoria interconnection to the extent of this capacity increment (approximately 180 MW above the current capacity of 1900 MW), should be pursued within a time frame that would require capital expenditure in the next regulatory control period, based on the successful completion of the regulatory test demonstrating that this project would deliver net market benefits.

Appendix C: Risk–free rate averaging period

The AER concurrently assessed the revised revenue proposals of two TNSPs (TransGrid and Transend) and the revised regulatory proposals of four DNSPs (ActewAGL, Country Energy, EnergyAustralia and Integral Energy). Within this appendix these six regulated businesses are collectively referred to as the network service providers (NSPs). For convenience, within this appendix the term regulatory proposal should be taken to include the term revenue proposal, where the AER is referring to the NSPs. Within this appendix the AER has also used the term draft decision to refer to any and all of the relevant draft decisions affecting the NSPs. Where it has been necessary to refer to a draft decision for just one of the NSPs, within this appendix the AER has identified the specific business when referencing the draft decision, rather than applying the generic term draft decision, as defined in the shortened forms.

The AER's consideration of the substantive arguments put forward by the NSPs in their revised regulatory proposals, submissions and consultant reports are set out below.[571]

Following the withholding of agreement to the averaging periods lodged with the regulatory proposals, the AER in consultation with the NSPs established the risk–free rate averaging periods (agreed averaging periods) prior to the draft decision. The AER views its agreed averaging periods decision as part of its draft and final decisions and has reviewed the further material provided by the NSPs as part of this final decision.

The AER notes that the NSPs' consultants appear to have based their advice on a legal interpretation of the NER.[572] The Competition Economists Group (CEG) stated that it has worked on the basis that when determining the averaging period it is a relevant consideration under the NER that the period should give rise to an estimate of the rate of return that is consistent with:[573]

> …the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non–diversifiable risk.

Although not necessarily agreeing with the NSPs and their consultants' interpretation of the relevant clauses, the AER has considered the key arguments put forward in the revised regulatory proposals and the additional material.

The NSPs' key argument is one that suggests an obligation on the AER to move away from the agreed averaging period if that period is set in abnormal times. The alleged abnormality affecting the agreed averaging period was not manifest at the time of the AER's July 2008 decision to withhold agreement. The issue therefore is whether the averaging periods in the revised regulatory proposals are reasonable compared with the agreed averaging periods.

571 The arguments put forward and consultant reports referred to by each NSP are set out in the cost of capital chapter.

572 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 4; Grundy B., p. 5 and Officer R.R., *Expert report prepared in respect of certain matters arising from the AER's NSW draft distribution determination*, 16 February, 2009, p. 4.

573 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 4.

C.1 Theoretical basis for the averaging period

In setting the averaging period close to the start of the next regulatory control period, the AER is seeking to set an unbiased risk–free rate to be applied in the weighted average cost of capital (WACC) formula, to derive an unbiased estimate of the regulated rate of return over the next regulatory control period.

In theory, the risk–free rate on the day that the regulatory determination comes into effect provides the best expectation of the future rate. This reflects the notion that the on–the–day rate fully reveals all the information available in the market. However, using the on–the–day rate exposes the firm to market volatility on a given day. Therefore, an averaging period is used to address the trade–off between 'volatility driven error' (due to exposure to an aberrant day) and 'old information driven error' (invalid past information) in interest rates. The averaging period also allows a firm to hedge its cost of debt over an extended period and counteracts the potential volatility of a single day's observation.

Professor Officer in his review of the CEG report accepted this theoretical position. He noted that:[574]

> In theory, the task of estimating the $Rf_{,t}$ is made easy because it is assumed constant and 'known for certain' at the time the rate is set. In practice there is no observed $Rf_{,t}$, instead the yield on a 10 year Commonwealth Bond/Security (CGS) is used as surrogate. This yield should theoretically be taken from the CGS as close as practical to the start date of the regulated period.

The AER considers the use of an averaging period as close to the start of the next regulatory control period as practically possible is consistent with the forward looking nature of the capital asset pricing model (CAPM) and is correct in finance theory.

C.2 The market risk premium

CEG stated that, in the NER the market risk premium (MRP) is fixed at 6 per cent but the risk–free rate is set within an averaging period. Therefore, it noted that using the most up to date estimate of the Commonwealth Government Securities (CGS) yield will only result in the most accurate estimate of the cost of equity if investors' cost of equity moves one for one with movements in CGS.[575] CEG also claimed that sampling yields from bond markets at these times (February 2009) and the foreseeable future will result in bond yields being sampled during abnormal market conditions and unreliable estimates of the cost of equity.[576] Further, it noted that in the current global financial crisis returns from holding government bonds have had a negative relationship with returns from holding equity.[577]

Strategic Finance Group (SFG) stated that the CAPM does not specify how to estimate the risk–free rate and asserted that it should be estimated in a way that gives the best

---

574 Officer R.R., p. 6.

575 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 7–12.

576 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 29.

577 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 11.

estimate of the required return on equity when combined with other input parameters.[578] Professor Grundy's underlying argument was that the MRP has increased and therefore an adjustment to the risk–free rate is appropriate. In particular, he stated that CAPM theory does not imply that the best estimate of the return on equity is either obtained by:

- adding 6 per cent to the risk–free rate at the start of the regulatory control period or
- adding 6 per cent to the moving average of the risk–free rate as close as possible to the start of the regulatory control period.[579]

Professor Officer also suggested that the MRP currently is higher than the MRP derived from long–term averages. Therefore, he noted that setting the risk–free rate which is at a 'low level' at current times relative to 'normal' whilst using a MRP from a more 'normal' time period does not result in an unbiased estimate of the cost of capital.

SFG stated that it is not necessarily the case that a fall in equity values must be caused by an increase in the required return on equity because a fall in future profits could also be the reason. However, based on its analysis, SFG noted that implausibly large reductions in expected corporate profits for implausibly long periods would be required to reconcile equity movements with the required return on equity estimated using the approach set out in the draft decision. Therefore, it concluded that the most plausible conclusion was that the required return on equity had risen over this period.[580]

The AER recognises that the CAPM does not state that the CGS is the best proxy for the risk–free rate. However, the CGS is arguably the most commonly used proxy when applying the CAPM in Australia—suggesting widespread acceptance in practice. In addition, the use of the CGS is specified in the NER.

The AER also recognises that the CAPM does not predict that the cost of equity capital necessarily moves one for one with the risk–free rate.

The AER notes that the arguments put forward by the NSPs regarding an insufficient return on equity is based on the view that the MRP of 6 per cent in the NER (based on a historical average) is out of line with the current variations in the MRP. In essence, the NSPs are arguing for a variable MRP to be applied in the CAPM, but given that it is prescribed in the NER they consider it reasonable to account for variations in the MRP via adjustments to the risk–free rate.

The AER considers that any implied (or actual) MRP changes cannot be addressed in this final decision. The AER notes that even if the MRP has increased somewhat over the last 12 months, it is unclear as to the margin of increase or whether there is an accepted theoretically sound methodology to take account of time varying MRP. The AER considers that a reasonable conclusion that can be drawn from current equity prices (if at all) would only be that the investors' perception of risk appears to have changed recently.

The AER notes that adjusting the risk–free rate averaging period as a mechanism to achieve the outcome equivalent to adopting a higher MRP (due to implied or actual

578 SFG Consulting, *Review of TransGrid approach to WACC averaging period*, 14 February 2009, pp. 17–18.
579 Grundy B., pp. 3–4.
580 SFG Consulting, p. 23.

variations to the historical MRP) is an attempt to circumvent WACC parameters prescribed (subject to five yearly reviews) in the NER. It would undermine the intended certainty provided under the regulatory regime which results from these values being prescribed.

Additionally, the AER notes that the NSPs' regulatory asset bases (RAB) are fixed (subject to depreciation and other NER prescribed adjustments) and receive regulated returns that comprise of both returns on equity and debt. Further, the NSPs' regulated cash flows provide significant certainty over earnings, dividends and debt servicing. This fixed RAB coupled with certainty in returns provide significantly more stable shareholder returns for the NSPs than for unregulated businesses whose future cash flows are highly uncertain. The NSPs are therefore insulated to a large degree from the factors that affect equity values during the current economic circumstances. In this context, arguments suggesting that returns provided to NSPs in a significantly more stable regulated environment should be comparable with higher expected returns for unregulated businesses due to the global financial crisis are unreasonable.

C.3 Historically low nominal risk–free rate

CEG stated that the weight of the regulatory precedent from overseas and Australia supports a view that if the most recent averaging period overlaps with abnormal levels of the risk–free rate or periods of economic crisis then such a period should not be adopted.[581]

The AER notes that this is a continuation of the argument for a variable MRP given the alleged abnormally low CGS yields. However, given the dramatic changes in circumstances within the economic environment the AER has considered whether in fact the agreed averaging periods will result in an unreliable estimate of the risk–free rate such that it no longer reflects a reasonable forward looking estimate.

The AER's discretion in setting the nominal rate of return under clause 6.5.2 of the transitional chapter 6 rules and clause 6A.6.2 of the NER is limited to determining the reasonableness of the averaging period used to derive the nominal risk–free rate and the debt risk premium. The proxy for the risk–free rate—based on CGS yield—and the maturity period (10 years), including the requirement to average the observed rates are prescribed in the NER. The debt risk premium is defined in terms of a margin between the CGS yield and a benchmark corporate bond with a credit rating of BBB+. Given the level of prescription, the AER considers that the NER intended for the WACC to vary over time in line with the interest rate cycle as opposed to being fixed.

The fact that CGS bond yields are at (or close to historical lows) does not of itself mean they cannot be used. Interest rates move all the time and reflect the market's assessment of the price of money at the time. Expectations about the prospect for prices and growth will influence this assessment. Brailsford, Handley and Maheswaran show that the nominal 10 year CGS yield averaged 5.7 per cent over 1883 to 2005 and 8.2 per cent over

581 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 64.

1958–2005. In comparison the CGS yield rate based on February 2009 is close to 4.3 per cent being 1.4 per cent below the long–term average.[582]

The AER considers that the material provided by the NSPs in support of their revised regulatory proposals does not reasonably justify that, an averaging period prior to 5 September 2008 or an averaging period of 12 months ending on 20 March 2009 is better than a period that is as close as practically possible to the start of the next regulatory control period. Moreover, the agreed averaging periods do not exclude the downward movement of the CGS yields commensurate with an easing in monetary policy and a softening in economic growth. The AER considers that the agreed averaging periods are not abnormal and setting the risk–free rate using this period is also consistent with the NEL objective of efficient investment. The AER therefore considers that the agreed averaging periods do not represent an abnormal period in relation to the observed CGS yields.

Given that all WACC parameters are prescribed in the NER except for the risk–free rate and debt risk premium, the AER considers that the WACC commensurate with interest rate expectations in the economy—resulting from the agreed averaging periods—is consistent with the NER and the NEL objective.

Professor Grundy referenced a paper by Krishnamurthy and Vissing-Jorgenson and stated that US federal government securities are biased downwards due to unique collateral and liquidity features relative to other assets. In the US market this was estimated at 1 per cent pre–September 2008. EnergyAustralia stated that previously, the ACCC had referenced other industry and accounting practices when making a decision and noted that the Institute of Actuaries of Australia (IAA) noted that the CGS yields were not necessarily a perfect proxy for the risk–free rate. EnergyAustralia stated that if the CGS yields were to be used—given the current market conditions and the liquidity premium paid for CGS—the IAA recommended an upward adjustment.[583]

The paper by Krishnamurthy and Vissing-Jorgensen (2008) considers the most appropriate indicator of the risk–free rate. Similarly, the IAA also appears to be considering the appropriate proxy for the risk–free rate. The AER notes that it has no discretion on using a proxy other than the CGS for the risk–free rate as it has been specified in the NER and therefore considers this reference irrelevant.

Professor Grundy noted that as the global financial crisis gathered, the gap between CGS and other zero beta debt securities has grown, as seen by the widening gap between NSW Treasury and CGS yields.[584] CEG also stated that the nominal CGS yields are depressed as evident by the high premium long–term state debt is attracting over the CGS yields and noted that this was due to the heightened demand for the liquidity of the CGS in a financial crisis.[585]

The AER understands CEG's argument as one suggesting that the CGS yield is an inappropriate proxy for the risk–free rate. The argument is based on the margin between

---

582 Tim Brailsford, John C Handley, Krishnan Maheswaran, *Re-examination of the historical equity risk premium in Australia*, Accounting and Finance 48 (2008), pp. 73–97.

583 EnergyAustralia, *Further submission on the AER's draft decision*, p. 9.

584 Grundy, pp. 10–11.

585 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 36–39.

CGS and state debt yields which is interpreted by CEG as evidence of the heightened demand for the liquidity of CGS.

The AER notes that Associate Professor Handley argues that it is unclear whether a premium should be paid for CGS or whether a discount should be applied to non–CGS assets due to their relative liquidity characteristics.[586] The AER therefore considers that it is unreasonable to conclude that the CGS yield is downwardly biased due to a heightened demand for the CGS liquidity.

The AER considers that the difference between the yields of state debt and the CGS does not diminish the suitability of the CGS as the best proxy for the risk–free rate. Moreover, the NER prescribes the use of the CGS as the risk–free rate. Additionally, the AER notes that the margin between state debt and CGS can also be attributed to a number of factors bearing on state government finances, including their debt servicing capacity.

C.4 Inconsistency between nominal and indexed bond yields

CEG stated that the AER should address the issue that an averaging period post September 2008 is likely to result in the adoption of CGS yields depressed in absolute terms as well as relative to the indexed CGS yields.[587]

The AER acknowledges that CGS yields have declined post September 2008 but notes that, as discussed above, this decline is not abnormal but consistent with changes in economic conditions.

CEG stated that since the global financial crisis the 'flight to safety' has resulted in such a high liquidity premium being paid for CGS that this now exceeds the 'peace of mind' premium being paid for indexed CGS. Therefore, CEG considered that if the AER's inflation estimates are applied in the current circumstances then it will make the estimate of the real risk–free rate less accurate rather than more accurate.[588]

The AER maintains its view that indexed CGS yields are not set in a well functioning market and therefore do not reflect informed market opinion or can be relied upon for deriving the future expectations of inflation (section 4.5.3). This issue was previously considered by the AER in the 2008 SP AusNet transmission determination and also referred to in the 2008 ElectraNet transmission determination. No evidence has been provided to the AER that these inefficiencies have now been addressed. Given the inefficiencies of the indexed CGS market, the AER considers that very little weight (if any) can be placed on outcomes derived by comparing relative movements between nominal and indexed CGS yields.

The AER considers that CEG's conclusions based on relative movements between nominal and indexed CGS yields are unreasonable because any such conclusion will be tainted with the inefficiencies in the indexed CGS market.

586 John C. Handley, *Comments on the CEG report: establishing a proxy for the risk–free rate, Report prepared for the AER*, 12 November 2008, p. 4.

587 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 40–46.

588 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 42.

C.5 Cost of debt

CEG stated that the best averaging period to estimate the cost of debt is the period that results in the best estimate of the cost of debt obligations actually entered into by the NSPs (or alternatively, obligations entered into by an efficient benchmark firm). Therefore, it stated that the best estimate of the cost of debt should be analysed based on whether debt is refinanced/hedged during the agreed averaging period or outside the period. CEG's view is that cost of debt will never be determined by a single averaging period and therefore, efficiently incurred debt will reflect debt market conditions over an extended period of years.[589]

The AER considers that the expected cost of debt over the regulatory control period should equal an estimate of the cost of debt at the start of the regulatory control period (as this is what the market at that time is requiring to invest in debt securities over the regulatory control period). As a proxy for the expected cost of debt, the yield to maturity (YTM) on an efficient benchmark firm's debt (prescribed by the NER as BBB+) at the start of the regulatory control period is adopted, irrespective of when the NSP issued the debt or the YTM on the debt it issued. The debt financing strategies of the NSPs are not prescribed by the AER. Even if firms could not hedge over an averaging period this does not imply that an estimate based on an averaging period close to the start of the regulatory control period is not the best forward looking unbiased estimate of the cost of debt over the regulatory control period or that it will systematically under compensate the regulated firm. The AER does not agree with CEG's underlying assumption that the best estimate of the cost of debt under the NER is an estimate set in an averaging period that a regulated business (or efficient benchmark business) is able to hedge/refinance its debt.

On the basis that the best estimate should be used, Professor Grundy stated that although the return on debt is independent of the risk–free rate, an estimate of the cost of debt ending on 5 September 2008 is appropriate.[590]

As discussed before, the AER notes that interest rates have reduced since September 2008 consistent with current monetary policy and growth expectations in the Australian economy. The AER therefore considers that an averaging period ending on 5 September 2008 is likely to result in expected over compensation of the regulated firm relative to the cost of the efficient benchmark. The RBA recently noted that average business lending costs on outstanding loans have declined by around 230 basis points since the start of the monetary policy easing cycle.[591]

The expected return on debt appears to have increased relative to the benchmark risk–free rate due to tightening in credit markets and the perception of increased risks in these markets. This could explain a narrowing of the difference between the required return on debt and the required return on equity. Debt is a fixed nominal cash flow claim while equity has a residual claim that is insulated against inflation. Therefore, the risks facing debt and equity are different and the required returns will be different. The AER considers that to the extent there is a narrowing of the difference between the required

---

589 CEG, Rate *of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 18–21.

590 Grundy, p. 4.

591 RBA, *Statement on monetary policy*, February 2009. Available: http://www.rba.gov.au/PublicationsAndResearch/StatementsOnMonetaryPolicy/Feb2009/domestic_financial_markets.html, viewed 13 February 2009.

return on debt and equity, it is driven primarily by the increased debt risk premiums. Such a change is consistent with the current global financial crisis which is primarily driven by a crisis in credit markets.

Comments regarding the accuracy of the Bloomberg data for calculating the cost of debt are considered by the AER in section 4.5.2 of this final decision.

C.6 Certainty and the averaging period

In its April 2008 report (prior to the draft decision), CEG noted that the main reason for the WACC parameters being set in the NER was the need for early certainty by the NSP about the rate of return to be earned and extending this logic to the averaging period would suggest an early period—even one that may be set before the AER's draft determination.[592] CEG reiterated the need for business certainty in its January 2009 report.

The AER does not agree that the main consideration for setting the WACC parameters was to provide the NSPs early rate of return certainty as interpreted by CEG. The AEMC's aim was to provide short–term stability regarding the WACC determination by reducing an important source of potential differences between regulatory decisions.[593] Contrary to CEG's interpretation, logically extending the AEMC's objective suggests that the averaging period should be consistent with the current AER practice as this would extend the intended regulatory certainty. Consistency with current regulatory practice is discussed in section C.7.

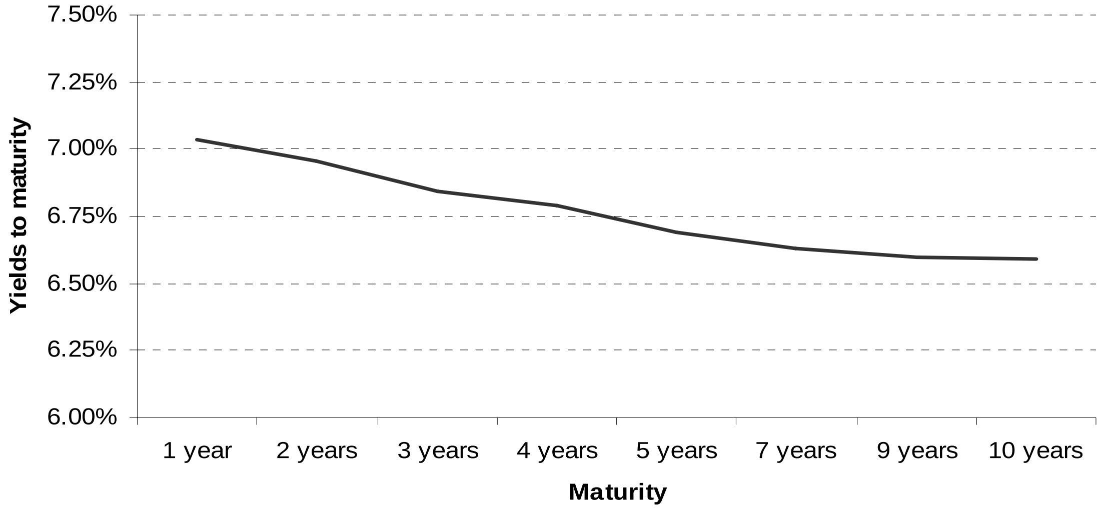
In the event that CEG's interpretation about early certainty is adopted, then it is akin to the regulator agreeing to set the regulated rate of return at whatever time the NSPs decide that is in their best interest to refinance debt/raise capital. This could create opportunities for 'gaming' the regulator. For example, an NSP can lock in an averaging period that it considers achieves the most advantageous rate of return early in the regulatory process based on its view of future interest rate movements but if its view transpires to be disadvantageous, expect the regulator to accept a different period later on in the regulatory process. As shown in figure C.1, in June 2008 when the AER received the NSPs' regulatory proposals, the interest rate yield curve was downward sloping. The downward sloping yield curve at that time reflects market expectations of lower interest rates in the future. Therefore, setting the risk–free rate based on an averaging period at that time would have lead to systematic ex ante overcompensation of firms relative to the efficient cost of capital and inconsistent with the forward looking nature of CAPM—that is, it would not result in an unbiased risk–free rate.

---

592 CEG, *Nominal risk–free rate, debt risk premium and debt and equity raising costs*, April 2008, p. 5 and CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 27.

593 AEMC, *Rule determination*, Rule No 2006 No. 18, p. 82.

Figure C.1: June 2008 yield curve for CGS



Source: Bloomberg data and AER analysis.
Note: Yield curve is based on a simple average of daily yields during June 2008.

EnergyAustralia argued that the AER did not specify proximity of the proposed averaging period to either the final determination or commencement of the regulatory control period in its 2007 Powerlink decision and that Powerlink's proposal was premised on the consideration of business certainty.[594]

The AER notes that the 2007 Powerlink final decision was originally targeted for completion in December 2006. On this basis, the averaging period proposed by Powerlink upfront at the start of the regulatory process was intended to be consistent with the AER/ACCC practice of setting the period as close as practicable to the start of the next regulatory control period.[595] However, the final decision was delayed to June 2007. As the averaging period was agreed early in the review process, consistent with standard practice, the AER did not change the averaging period to take account of the delay with the final decision date.

The AER considers that the additional material put forward by the NSPs does not support the view that its decision on the agreed averaging periods was inconsistent with the NER.

C.7 Consistency with regulatory practice

The AER considers that given the evidence at the time, the additional material contained in the revised regulatory proposals do not justify a conclusion that the AER's decision to withhold agreement to the proposed averaging periods and consequently the agreed averaging periods were inconsistent with regulatory precedent. The AER notes the following:

---

594 EnergyAustralia, *Revised regulatory proposal*, attachment 8A, p. 4.
595 Powerlink, Letter to AER – risk–free rate — confidential, 7 December 2005.

- The approach is consistent with recent transmission determinations made under chapter 6A of the NER for ElectraNet and SP AusNet.[596]
- The AEMC's National Electricity Amendment (*Economic regulation of transmission services*), Rule 2006 No. 18, rule determination recognised the need for consistency with the ACCC's WACC methodology and parameters contained in the ACCC's 2004 Statement of Regulatory Principles.[597]
- The AEMC's transmission rule (noted above) was adopted by the Standing Committee of Officials of the Ministerial Council on Energy for the WACC in the transitional chapter 6 rules.[598]
- The AER's approach was recently enunciated in its WACC review issues paper released in August 2008.[599] It was noted that:[600]

  > The AER's current approach is to accept a proposed starting date to the averaging period which is as close as practically possible to the commencement of the regulatory control period, to ensure an unbiased estimate of the risk–free rate (and the corporate bond rate).

- In the WACC review issues paper, the AER specifically asked whether the practice of accepting any averaging period of between 5 and 40 days and commencing as close as possible to the start of the regulatory control period should be reconsidered. In response, the Joint Industry Associations (JIA) stated that:[601]

  > The businesses are of the view that the current regulatory practice of averaging contained in the NER is acceptable.

- JIA also submitted that the regulated businesses should have the discretion to select the start date and noted that continuing the current practice:[602]
  - provides consistency with regulatory precedent thereby minimising regulatory risk
  - provides consistency with existing practices arising from this in tapping and accessing debt and equity markets
  - provides regulated electricity transmission and distribution businesses with an opportunity, but not an obligation, to raise a portion of the debt during the averaging period

---

596 AER, *Final decision ElectraNet 2008–09 to 2012–13*, and AER, *Final decision SP AusNet 2008–09 to 2013–14*.

597 AEMC, *National Electricity Amendment (Economic regulation of transmission services) Rule 2006 No. 18, Rule determination*, November 2006, pp. 85–86 and AEMC, *Draft rule determination, Draft national Electricity Amendment (Economic regulation of transmission services)*, 26 July 2006, pp. 56–57.

598 SCO, *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution*, Explanatory Material, p. 44. Available: www.ret.gov.au/Documents/mce/emr/governance; and EnergyAustralia, *Supplementary submission on NER exposure draft*, 31 May 2007, attachment 1. Available: www.ret.gov.au/Documents/mce/emr/governance.

599 AER, *Issues paper, Review of the WACC parameters for electricity transmission and distribution*, August 2008.

600 AER, *Issues paper*, *Review of the WACC parameters*, p. 36.

601 JIA, *Network Industry Submission, AER issues paper–Review of the WACC parameters for electricity transmission and distribution*, September 2008, pp. 76–77.

602 JIA, pp. 76–77.

- allows regulated electricity transmission and distribution businesses to build a debt profile of multiple debt financing to minimise risks.

- The AER's WACC review draft decision formalised its current approach and proposed to retain the current NER methodology subject to only accepting an averaging period commencing as close as practically possible to the start of the regulatory control period.[603] This formalisation of the current approach was not objected to by JIA in its submissions on the WACC review draft decision.

C.8 NEL revenue and pricing principles

Revenue and pricing principles in the NEL state that an NSP should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control services and complying with a regulatory obligation or making a regulatory payment.[604]

The NSPs submitted that the AER should have regard to whether the selection of the averaging period in determining the rate of return provides a reasonable opportunity to recover at least the efficient costs.[605]

Clause 6.5.2(b) of the transitional chapter 6 rules and clause 6A.6.2(b) of the NER prescribe the WACC methodology (including the CAPM) for calculating the regulated rate of return. The AER considers that the agreed averaging periods are consistent with finance theory. Moreover, the determined WACC is consistent with the NER and as intended moves commensurate with interest rate changes in the Australian economy which is also consistent with the NEL objective of promoting efficient investment. The fact that the risk–free rate is at (or close to) historical lows does not by itself mean that the resulting WACC does not provide a reasonable opportunity to recover the efficient costs of capital.

The AER notes that the WACC parameters are based on benchmarks and are part of the incentive framework. Therefore, the NSPs have an opportunity to achieve a higher rate of return by better managing their operating costs.

Under incentive regulation, firms generally receive the benefits and incur the cost of deviating from the efficient benchmark. Rewarding firms for losses incurred when they deviate from the efficient benchmark may encourage firms to act in this manner as they will expect to incur any upside from taking on risk and not suffer from the downside. An incentive mechanism with such expectations built in may encourage excessive risk taking inconsistent with the revenue and pricing principles in the NEL that require incentives to promote economic efficiency.[606]

Given the significant future capex programs and the evolving changes in the Australian economy in 2009, the AER requested confirmation from the NSPs on whether they are

603 AER, *Explanatory statement, Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters*, December 2008, p. 133.
604 NEL, clause 7A(2).
605 EnergyAustralia, *Revised regulatory proposal*, p. 58.
606 NEL, clause 7A(3).

able to fund their respective capital programs. In response, the NSPs confirmed their ability to fund the capital programs for the next regulatory control period.[607]

Generally, the AER does not place much weight on WACC comparisons across regulatory control periods. However, in the absence of information supporting the NSPs' assertion that the agreed averaging period for setting the risk–free rate will result in inconsistency with the NEL revenue and pricing principles, a comparison was undertaken.

The IPART and the ICRC determined a pre–tax real WACC of 7.0 per cent applicable to the NSW DNSPs and ActewAGL respectively for the current regulatory control period.[608] This compares with an equivalent pre–tax real WACC of about 6.8–6.9 per cent for the next regulatory control period under this final decision.[609] For TransGrid's/ EnergyAustralia's (transmission) and Transend's current regulatory control period the ACCC determined a nominal vanilla WACC of 9.08 and 8.80 per cent respectively and these compare with a nominal vanilla WACC of 8.79 per cent and 8.80 per cent for the next regulatory control period.[610] The AER notes that during the period December 2003 to March 2005 the RBA's cash rate was between 5.00–5.25 per cent whereas during the agreed averaging period it was at 3.25 per cent.[611] Noting this reduction in the cash rate commensurate with a softening in economic growth, the AER considers that the NSPs' WACC for the next regulatory control period (although lower) is reasonable compared to the WACC in the current regulatory control period.[612]

Overall, the AER considers that the NSPs are not being deprived of a reasonable opportunity to recover their efficient cost of capital.

C.9 Conclusion

Based on the above reasons the AER considers that its decision to withhold agreement to the averaging periods nominated in the NSPs' regulatory proposals is reasonable and that its agreed averaging periods are consistent with finance theory, regulatory practice, the NER and NEL.

607 Country Energy, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 18 February 2009; EnergyAustralia, letter to the AER, *Deliverability of capital expenditure program*, 17 February 2009; Integral Energy, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 18 February 2009; TransGrid, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 27 February 2009; and Transend, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 17 February 2009.

608 IPART, *NSW electricity distribution pricing 2004/05 to 2008/09, final report*, June 2004, pp. 217–218 and ICRC, *Investigation into prices for electricity distribution services in the ACT, final decision*, March 2004, p. 70.

609 This varies depending on the effective tax rate modelled for each NSP.

610 ACCC, *Tasmanian transmission network revenue cap, 2004 – 2008/09, final decision*, December 2003 and ACCC, *Final decision TransGrid 2004–05 to 2008–09.*

611 RBA, Cash rate target, viewed 23 March 2009. Available: <http://www.rba.gov.au/Statistics/cashrate_target.html>

612 On 7 April 2009 the RBA further reduced the cash rate to 3.0 per cent.

Appendix D: Self insurance

This appendix sets out the AER's assessment of TransGrid's proposed self insurance allowance in its opex forecast for the next regulatory control period.

AER considerations

AER approach to assessing self insurance premiums

The AER considers that its approach to the assessment of TransGrid's self insurance claims and the proposed alternative self insurance amounts is consistent with the requirements of the NER.

Clause 6A.6.6(c) of the NER states that the AER must accept TransGrid's forecast of opex if it is satisfied that the total of the forecast opex reasonably reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives. Clause 6A.6.6(d) of the NER requires that if the AER is not satisfied, it must not accept the forecast opex.

Further, clause 6A.14.1(3)(ii) of the NER states that where the AER does not accept the forecast opex, the AER must set out its reasons for that decision and an estimate of the total of the TNSP's required opex for the regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

The opex factors which must be taken into account in deciding whether or not the AER is satisfied with the proposed costs or in determining a substitute amount are set out in clause 6A.6.6(e) of the NER. In determining the prudence and efficiency of TransGrid's self insurance claims, the AER considered that the following opex factors, outlined in the NER, were of most relevance:

- clause 6A.6.6(e)(1)—the information included in or accompanying the revenue proposal
- clause 6A.6.6(e)(3)—analysis undertaken by or for the AER and published prior to or as part of the draft decision or the final decision
- clause 6A.6.6(e)(4)—benchmark opex that would be incurred by an efficient TNSP over the regulatory control period
- clause 6A.6.6(e)(5)—the actual and expected opex of the TNSP during any preceding regulatory control periods.

Each of these opex factors and their application is discussed below.

In assessing TransGrid's self insurance under clause 6A.6.6(c) of the NER the AER notes that it must have regard to the information included in or accompanying the revenue proposal as outlined in clause 6A.6.6(e)(1) of the NER. Therefore, the NER implies that the revenue proposal should include sufficient information to justify TransGrid's self insurance cost forecasts, or in the event that the AER does not accept the forecasts, that there is sufficient information for which the AER may substitute an alternative forecast. This interpretation is supported by clause 6A.13.2(a) of the NER which states that:

> If the AER's final decision is to refuse to approve an amount or value referred to in clause 6A.14.1(1), the AER must include in its final decision a substitute amount or value which, except as provided in paragraph (b), is:
>
> (1) determined on the basis of the current Revenue Proposal; and
>
> (2) amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

The AER considers that it is not the intent of the NER that the AER generate forecasts on behalf of TransGrid where it has not provided adequate information in its revenue proposal. Instead, the AER considers that the onus is on TransGrid to provide the necessary information to support its forecasts.

TransGrid noted that an actuarial review of the AER position on self insurance was not undertaken.[613] Clause 6A.6.6(e)(3) of the NER states that the AER may have regard to analysis undertaken by or for the AER. The AER notes that it is not required by the NER to engage an expert (for example an actuary) to review any opex forecast proposed by TransGrid. Further, it is not always necessary to seek the assistance of an expert to decide whether an opex forecast is reasonable. Depending on the level of information provided, the AER may be able to satisfy itself that the forecast expenditure is reasonable or unreasonable, without the need of an expert.

In considering clause 6A.6.6(e)(4) of the NER, the AER notes that benchmarking of self insurance costs could potentially provide an indication of the reasonableness of a self insurance claim. However, the AER notes that there:

- is no agreed definition of the individual events that should be included in a self insurance claim—the included events are at the discretion of the individual TNSP
- appears to be no agreed definition on what each of those events is to cover.

Since self insurance events and their associated costs are not readily comparable across businesses, it is unlikely that benchmarking will provide a reasonable self insurance cost for an individual TNSP.

In considering clause 6A.6.6(e)(5) of the NER, the AER notes that self insurance was provided for TransGrid in the current regulatory control period.[614] The AER considers that this previous self insurance allowance may provide a basis on which to consider the self insurance claim in the next regulatory control period. However, the AER notes that:

- TransGrid did not refer to the existing allowances in developing its forecasts for the next regulatory control period
- based on the benchmarking discussion above, the self insurance events included and the definition of these events is at the discretion of the individual TNSP—there is no reason for these to be consistent between regulatory control periods
- the calculation of premiums may differ from one period to the next due to issues such as greater or lesser attention to risk mitigation strategies.

---

613 TransGrid, *Revised revenue proposal*, p. 75.

614 ACCC, *NSW and ACT Transmission Network Revenue Cap, TransGrid 2004–05 to 2008–09: Decision*, April 2005.

Based on its assessment of the relevant opex factors, the AER considers it necessary to rely on the information provided in the revenue proposal (consistent with clause 6A.6.6(e)(1) of the NER) in determining whether the proposed self insurance allowances reasonably reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives. Consequently, where the information concerning an individual self insurance claim was inadequate—that is, it did not appear to support the claim—the AER has not accepted the forecast (consistent with clause 6A.6.6(d) of the NER).

Similarly, in determining a substitute self insurance value, the AER relied on the information included in the revenue proposal (as required by clauses 6A.14.1(3)(ii) and 6A.13.2 of the NER). For a number of risks, based on the information provided to the AER in TransGrid's revenue proposal and revised revenue proposal, the only value that the AER could assign to an event was zero because there was no, or inadequate information on which to base an alternative amount. Such a value is not meant to indicate that the self insurance event may or may not occur, rather, the AER has assigned a cost of zero due to the (lack of) information provided in the revenue proposal.

Generally, the self insurance premiums proposed by TransGrid were accepted where the business was able to provide historical data related to the incidence and cost of an event in order to calculate the premiums. In the absence of such information, the AER accepts that a self insurance premium may be derived on the basis of information from other sources, including qualitative information. However, in such circumstances, as with any opex forecast, the onus is on the business to provide a compelling rationale for the use of that information or set of assumptions and to explain how such information has been used to derive the cost forecast (self insurance premium).

In a number of instances, SAHA justified its probability calculations on the basis that the assumed probability is a much more reasonable assumption. It stated its assumed probability produces an outcome that more reasonably reflects the efficient cost that a prudent operator is likely to incur in the next regulatory control period, compared with the AER's approach of excluding the proposed cost in its entirety. The AER does not consider that such an assertion represents an appropriate justification for the probabilities and associated self insurance premiums presented by SAHA.

Further, it is not sufficient for SAHA to simply state that a self insurance premium is reasonable without providing evidence in support of this claim. It is not adequate, for example, to suggest that since an event has impacted another electricity business that it is also likely to impact TransGrid.[615] Nor is it sufficient to apply a probability to the occurrence of such an event based on the occurrence in another business. The onus is on the business to provide the necessary information to support its forecasts to allow the AER to determine whether the forecast opex reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the opex objectives. Such supporting information should reasonably include:

- the rationale used to determine the reasonableness of the forecast

[615] For example, the nature of the operations and assets, location of the network and risk mitigation programs to protect assets and income can influence the likelihood of an event occurring and the financial impact of that event.

- the process that the business underwent in determining the probability and cost estimates
- the factors that led the business to believe that the experience in another business can be applied to the business in question and how these factors have been translated into a premium
- why one value for the forecast risk is preferred over another.

SAHA indicated that its self insurance estimates were reviewed by an independent actuary. Based on this review, the reviewing actuary concluded that '…the approach adopted by SAHA is sensible given the nature of the risks involved and the assumptions are not unreasonable' and suggested that '…the self insurance figures presented in the report are suitable for recognition as an operating expense.'[616]

In relation to the review the AER notes that:

- the scope of the review was limited to an examination of the methodology used by SAHA for determining risk and assessing the assumptions for reasonableness
- the review was restricted to the information supplied by SAHA, and the supporting information and data was not sighted by the actuary
- the review did not include identification of the risks which are self insured
- the review states that '…a wide range of assumptions can be made which may be considered reasonable but may result in significantly different risk premiums'[617]
- no details of the actuary findings were provided in the review and the actuary did not review the final SAHA report to determine if its suggestions and recommendations were incorporated.[618]

The AER is concerned that, in relation to the self insurance premiums, SAHA indicated that '…supporting data used to derive those figures were approved and signed off by an independent actuary'[619], whereas the review indicates that supporting information and data was not sighted by the actuary.[620] Accordingly, it is not clear that SAHA's statement that its self insurance estimates have been approved by an independent actuary can be relied upon.

Notwithstanding the above, given the limitations in scope and analysis, the AER is unsure of the usefulness of the review. In particular, without a robust assessment of the entire self insurance premium calculations, including an examination of the underlying data used to calculate the premiums, it is not clear what information the AER is supposed to derive from such a review. Based on the scope and analysis presented, the review simply represents an assessment of the process applied by SAHA to the data provided by SAHA—it provides no assurance to the AER that the resultant premiums are appropriate.

616 TransGrid, *Revised revenue proposal,* confidential, Appendix K.
617 TransGrid, *Revised revenue proposal,* confidential, Appendix K,
618 The actuary noted, however, that these are relatively minor in nature and would not materially affect the assessment. TransGrid, *Revised revenue proposal*, confidential, Appendix K.
619 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 6.
620 TransGrid, *Revised revenue proposal,* Appendix K, confidential,.

Similarly, the review provides no information on whether the premiums were derived on the same or similar basis to that which would be used by the actuary (if these were derived by the actuary from the bottom up) or that the proposed premiums are the same or similar to those that the actuary would have produced.

While the AER accepts that an actuary reviewed SAHA's self insurance estimates, the review is not equivalent to an actuarial preparation of self insurance estimates. Based on its previous assessment of self insurance proposals, the AER notes that the preparation of self insurance estimates by an actuary typically involves the collection of historical and other relevant information, the application of quantitative techniques to obtain frequency and severity factors for identified risk categories and the use of risk modelling to obtain simulated distribution parameters.[621]

SAHA stated that where the AER has decided to reject a self insurance premium for a particular risk it should allow TransGrid to mitigate such risks in another way.[622] The AER notes that it is not required under the NER to propose alternative means of mitigating risks that TransGrid may face during the next regulatory control period. Rather, it is required to assess the forecast opex put forward by TransGrid, either accept or reject the forecast opex, and propose a substitute value based on the requirements set out in the NER.

Revised self insurance premiums

Environmental contamination

Self insurance is sought in relation to aspects of TransGrid's business that could potentially expose it to the risk of unintentionally polluting its surrounding environment, which could lead to a range of legal and financial consequences. SAHA proposed a self insurance premium for environmental contamination of $500 000 per annum.[623]

SAHA calculated the premium based on historical observations over the last 5 years. SAHA chose to exclude from these observations incidents under the direct control of TransGrid and also made an adjustment for future remediation work.

In the draft decision the AER rejected TransGrid's proposed self insurance premium on the basis that TransGrid's potential exposure to such events was not clear and there was insufficient information regarding historical incidents.

In response, SAHA noted that the five years of historical data presented in SAHA's original report was the only data available to support any quantification of this risk. Further, SAHA indicated that its original report included a reduction in the self insurance

621 See for example *ElectraNet Transmission Network Revenue Proposal 1 July 2008 to 30 June 2013 - Appendix K*, May 2007 at http://www.aer.gov.au/content/item.phtml?itemId=712378&nodeId=3c71ef78e74a8f7eb396ac3f60a70d95&fn=Appendix%20K%20ElectraNet%20Self%20Insurance%20Risk%20Quantification%20Report%202006.pdf.

622 SAHA, *Response to the draft decision – Self insurance*, confidential, p. 53.

623 SAHA, *TransGrid – Self Insurance Risk Quantification, supplementary report–response to AER/PB*, confidential, p. 8.

premium to account for a one off incident under the direct control of TransGrid and the future remediation of the worst affected sites.[624]

SAHA suggested that its approach to determining the self insurance premium was a much more reasonable approach when compared with the AER's approach of excluding the cost associated with this risk in its entirety.[625]

SAHA also included a recalculation of the self insurance requirements for environmental contamination to recognise the fact that some costs associated with environmental contamination were likely to be subject to a time lag before being incurred by the business. A discount factor was then applied to the anticipated costs to reflect the effect of this time lag. Accordingly, the self insurance premium was revised from \$500 000 per annum to \$200 000 per annum.[626]

The AER acknowledges the points raised by SAHA, but notes that the self insurance premium was originally rejected on the basis that the potential exposure to such events was not clear.[627] As noted in the draft decision, the AER's uncertainty regarding TransGrid's potential exposure to such events stems from the following statements in the original SAHA report:[628]

> SAHA is assuming that (the current external insurance) only covers personal property belonging to the insured. Therefore, it appears that TransGrid might be fully exposed to any third party liability claims stemming from gradual pollution events.

The AER was unable to determine the validity of the self insurance claim on the basis of *assumed* external insurance coverage and the fact that TransGrid *might* be exposed to third party claims.

In addition, the AER indicated in the draft decision that there was insufficient information regarding the historical incidents of pollution.[629]

The AER has since received additional information from TransGrid confirming that TransGrid does not have external insurance coverage for gradual pollution events and is therefore exposed to third party claims associated with such incidents. In addition, TransGrid provided information concerning the historical incidents of gradual pollution on its network.[630]

Based on the information provided, the AER is satisfied with the assumptions used by SAHA to calculate the self insurance premium for environmental contamination. As a result, the AER accepts the proposed self insurance premium of \$200 000 per annum.

---

624 SAHA, *Response to the AER's Draft Decision – Self insurance*, confidential, p. 53.
625 SAHA, *Response to the AER's draft decision – Self insurance*, confidential, p. 32.
626 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 53.
627 AER, *Draft decision*, p. 284.
628 SAHA, *TransGrid Self Insurance Risk Quantification*, confidential, p. 42.
629 AER, *Draft Decision*, p. 284.
630 TransGrid, *Response to Issue 324 – Environmental Contamination Self Insurance Allowanc*e, 24 February 2009.

Summary

The AER accepts the self insurance premium of $200 000 per annum for TransGrid for environmental contamination.

Bomb threat and terrorism

TransGrid proposed a self insurance premium for the cost impact of a bomb threat, hoax or terrorism event.[631] The proposed self insurance premium for this risk is $23 500 per annum which is made up of the self insurance component for the impact of a bomb threat, hoax or extortion ($5200) and a component for acts of terrorism ($18 300).

In the draft decision, the AER accepted TransGrid's self insurance premium for the impact of a non–terror related bomb threat, hoax or extortion. However, the AER did not accept the self insurance premium for the risk of a terrorist event on the basis that calculating a self insurance premium is difficult and that a terrorist event is listed as a defined pass through event under the NER.[632]

In its response, SAHA suggested that the materiality threshold associated with any cost pass through application means that the affected regulated business would not be compensated for bearing this risk when the net impact does not pass the materiality threshold.[633] SAHA therefore considered that the risk of a terrorism event is best addressed through self insurance rather than as a cost pass through and recommended that the original self insurance estimate for TransGrid be reinstated by the AER.[634] SAHA did not provide additional information in support of its original self insurance premium.

The AER considers that the choice between managing an event through self insurance or cost pass through should reflect the nature of the event. For example, such a decision should rely primarily on whether the frequency and cost associated with an event can be robustly determined and whether the event would result in catastrophic losses to the business. The materiality threshold applied to a cost pass through event is not a relevant consideration in this context.

Further, the AER reiterates that a terrorism event is included as a defined pass through event in the NER. The AER therefore maintains its position in the draft decision and rejects the claim for self insurance of a terrorism event. If a terrorism event occurred TransGrid would be able to submit a pass through application to cover the reasonable costs associated with the event under the NER. The AER would assess any such application, in accordance with the NER and any relevant guidelines, at the time the application was lodged.

Summary

The AER maintains its draft decision and accepts the premium of $5200 per annum for TransGrid for the bomb threat, hoax or extortion risk. The AER does not accept the self insurance premium for terrorism event on the basis that such an event is included as a defined pass through event in the NER.

---

631 TransGrid, *Revised revenue proposal*, p. 74.

632 AER, *Draft decision*, p. 285.

633 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 26.

634 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 26.

Earthquake risk

TransGrid proposed self insurance premiums for the cost impact of earthquakes of magnitude five and six impacting on its network. The proposed self insurance premium for the impact of an earthquake on TransGrid's assets is $165 000 per annum. This premium is made up of an amount for the impact of an earthquake of between magnitude five and magnitude six ($146 000) and an amount for the impact of an earthquake above magnitude six ($19 000). The self insurance premium reflects the costs associated with repairing TransGrid's assets and an amount for public liability in the event of an earthquake.

In the draft decision, the AER accepted the self insurance premium proposed by TransGrid for the impact of an earthquake between magnitude five and six. However, the AER did not accept the premium in relation to above magnitude six earthquakes for TransGrid on the basis that SAHA had not provided a reasonable basis for the adoption of a 1 in 166 year probability of an above magnitude six earthquake in NSW.[635]

In response to the draft decision, SAHA suggested that the AER has made the decision to exclude a self insurance risk allowance that is not supported by historical data.[636] SAHA argued that:[637]

> such an approach is generally inconsistent with good risk management practices—namely that just because such an event has not occurred historically, does not mean that there isn't a risk of it occurring sometime in the future.

The AER agrees that an above magnitude six earthquake in NSW is possible, however, the AER is not required to determine if an event is possible or not. Rather, the AER is required (under the NER) to assess the associated opex—in this case, the self insurance premium. In doing so, the AER notes that SAHA's analysis acknowledged that there have been no above magnitude six earthquakes recorded in NSW since records have been kept. However, SAHA indicated that, given that other such earthquakes have occurred in Australia over that period, it '…has assumed that there is a potential for at least one magnitude 6 earthquake to occur' and has assumed an expected value of 1 in 166 years for TransGrid.[638]

The AER notes that SAHA provided no further information in relation to this proposal or for the derivation of the probability including any comment from an actuary who reviewed its report. The AER considers that the argument presented by SAHA does not constitute a satisfactory examination of the risks of such an earthquake in NSW. SAHA has not demonstrated that this probability is any more reasonable than, for example, 0 in 166 years or 1 in 300 years. The AER requires supporting information from SAHA to understand how it derived this probability and to determine whether the probability actually represents a reasonable value or that some other probability is not preferred.

In the absence of such supporting information, the AER is unable to determine if the probability is reasonable. Accordingly, the AER is not satisfied that the proposed self insurance allowance reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.

---

635 AER, *Draft decision*, p. 286.
636 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 27.
637 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 27.
638 SAHA, *TransGrid Self Insurance Risk Quantification*, confidential, p. 56.

The AER notes that it is unable to derive a substitute efficient premium for this risk due to the lack of supporting information provided in the revenue proposal and the revised revenue proposal.

Summary

The AER maintains its draft decision and does not accept the proposed self insurance allowance for TransGrid for an above magnitude six earthquake. The AER maintains its draft decision and accepts the self insurance premium of $146 000 per annum for TransGrid for earthquakes of between magnitude five and six.

Bushfire risk

SAHA's original assessment of bushfire risk was separated into two types of bushfires—those ignited by TransGrid's own assets, and those ignited by a third party. Further, SAHA originally calculated self insurance premiums in relation to:

- very minor bushfires—that is, bushfires causing damage below $1 million
- minor bushfires—that is, bushfires causing damage above $1 million
- major bushfires—that is, bushfires causing more than $10 million damage.

Bushfires ignited by TransGrid's own assets

The self insurance premium for bushfires ignited by TransGrid's own assets consists of a premium associated with 'very minor' bushfires ($3000), a premium for minor bushfires ($50 000) and a premium for major bushfires ($8000).

In the draft decision, the AER accepted the self insurance premium for very minor bushfires.[639]

In the case of minor bushfires, TransGrid indicated that its assets have not started a bushfire that has lead to damage of greater than its $1 million insurance deductible. However, SAHA considered it reasonable to adopt a probability of 1 in 20 years for such an event.

In the draft decision, the AER rejected the claim for self insurance, indicating that SAHA has not provided robust basis for the adoption of a 1 in 20 year probability of a minor bushfire.[640]

The AER notes that SAHA has provided no further evidence in support of the proposed 1 in 20 year probability. SAHA's argument for the adoption of a 1 in 20 year probability for such an event consisted of a statement that, notwithstanding that there have been no previous claims, SAHA considered it '…reasonable to assume that TransGrid can potentially ignite one minor bushfire once every 20 years…'.[641]

While this risk may well exist for TransGrid, based on the limited information provided by SAHA, the AER is unable to accept that the 1 in 20 year probability adopted by SAHA is reasonable. SAHA has provided no rationale for the adoption of this particular probability or explained why the probability should be considered reasonable. The AER

639 AER, *Draft decision*, p. 287.
640 AER, *Draft decision*, p. 287.
641 SAHA, *TransGrid Self Insurance Risk Quantification*, confidential, p. 77.

therefore rejects the associated self insurance premium on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to determine a self insurance allowance.

Based on the assessment above, the AER is not satisfied that the self insurance premium for a minor bushfire ignited by TransGrid's own assets reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute efficient premium for this risk due to the lack of supporting information provided in the revenue proposal and the revised revenue proposal.

In relation to a major bushfire ignited by TransGrid's assets:

- SAHA determined the number of bushfires in NSW caused by electricity assets (8 per annum over the past 13 years).[642] SAHA indicated that this translated to approximately 104 (i.e. 8 × 13) bushfires caused by electricity assets over the past 13 years since the inception of TransGrid.
- SAHA noted that over this (13 year) period, only one major bushfire had occurred–the Appin fire started by Integral Energy. SAHA therefore calculated the probability of a minor bushfire ignited by electricity assets becoming a major bushfire as 1 in 104 (or 1 in 13 years).
- SAHA then applied the average annual number of very minor bushfires caused by TransGrid's assets to the expected probability of a bushfire (of any size) becoming a major bushfire (i.e. 1 in 104) to determine the individual probability of a major bushfire for TransGrid.
- SAHA then reduced this probability to reflect the fact that TransGrid's operating region covers both NSW and the ACT.
- SAHA calculated the cost of a major bushfire ignited by TransGrid's own assets on the basis of information from the Centre for International Economics (CIE)[643] and TransGrid's asset data.

In the draft decision, the AER rejected the claim for self insurance, noting, in particular, that:[644]

- SAHA provided no rationale for the application of a 13 year historical period.
- The fact that 1 bushfire has occurred since the inception of TransGrid (in Integral Energy's network) does not provide a basis for assuming that another major bushfire will occur every 13 years—there are other factors that impact on the probability of such an event.
- The SAHA data concerning the number of bushfires in NSW caused by electricity assets includes those caused by both transmission and distribution assets. Given the differences in coverage between the transmission and distribution networks, it is not

642 Based on information concerning minor bushfires provided to SAHA by the NSW electricity businesses.
643 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, November 2000.
644 AER, *Draft decision*, pp. 287–288.

clear that the combined total can be used as the basis for determining the probability of a bushfire caused by TransGrid's assets.

- It is not clear that TransGrid's experience with very minor bushfires can be used to predict the possibility of a major bushfire.
- The functional relationship between damage costs and area burnt proposed by CIE cannot be relied upon.
- The explanatory power of the proposed CIE functional relationship is poor. The coefficient of determination is reported as 0.39, implying that only 39 per cent of the variation in bushfire damage cost can be explained by the amount of hectares burnt.[645]

SAHA responded to the draft decision by indicating that:[646]

- the inception date signified the period where SAHA was able to collect meaningful data recorded by the businesses and therefore able to derive estimation for the probability
- SAHA believed that it was logical to assume that any minor bushfire may become a major bushfire and therefore, considers the use of minor bushfire to predict the possibility of a major bushfire reasonable
- SAHA used the Appin fire (in the Integral Energy network) to derive the probabilities of the businesses starting a major bushfire and did not assume this occurrence as a basis of the probability. SAHA indicated that if that was not the case, the probability of Integral Energy starting a bushfire would be 1 in 11 years[647] but instead, SAHA had estimated it to be 1 in 30 years.[648]

While the AER acknowledges the above points, it notes that the response from SAHA does not address the previous point that the calculated probability for TransGrid is based on an assumption that a major bushfire will occur in NSW every 13 years (the value of the resultant calculated probability for Integral Energy, 1 in 30 years, is not relevant in this respect).[649] The key point is that the basis of the calculated probability for TransGrid—that is, the assumption that a major bushfire occurs every 13 years—has not been adequately justified. As previously indicated, SAHA has provided no information in support of the 1 in 13 year assumption.

As justification for its probability calculations, SAHA attempted to demonstrate that the calculated return period for a major bushfire for Integral Energy, 1 in 30 years, was correct. SAHA provided additional information from the Emergency Management Australia (EMA) Disaster Database showing that there were two major bushfires ignited by electricity assets in NSW over the past 68 years (consistent with the 1 in 30 year probability of a major bushfire calculated by SAHA).[650]

645 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 113.
646 SAHA, *Response to the AER's draft decision – Self insurance*, confidential, p. 30.
647 The AER notes that the probability estimate used in the case of the NSW DNSPs was 1 in 11 years as opposed to the 1 in 13 years reported in the case of TransGrid.
648 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential,, p. 30.
649 The AER notes that, in relation to the calculation of self insurance premiums for the NSW DNSPs, SAHA used a probability of 1 in 11 years.
650 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 31.

The AER notes, however, that in relation to one of these bushfires (in EnergyAustralia's network), there was no information to support SAHA's contention that this was a major bushfire—that is, greater than $10 million damage. The event resulted in damage to 950 hectares (substantially below the 80 000 hectares that SAHA suggested is associated with a major bushfire and the 44 000 hectares associated with a minor bushfire[651]) and the event was not previously identified by EnergyAustralia as a major bushfire.[652] Accordingly, it is not clear that this event was in fact a major bushfire as defined by SAHA. Based on the information provided by SAHA, it appears that there has only been one major bushfire ignited by electricity assets in NSW in the past 68 years. This appears to contradict the application of a 1 in 13 year probability previously used to determine major bushfires started by electricity assets in NSW and the 1 in 30 year return period associated with a major bushfire in the Integral Energy network.

While the AER appreciates that the information regarding major bushfires may not have been reported in sufficient detail in the EMA Disaster Database to identify the cause of those bushfires, SAHA has provided no further information to support a more frequent occurrence than that observed in the information provided. The AER therefore rejects the probability of a major bushfire ignited by TransGrid's own assets, as derived by SAHA, on the basis that the information provided by SAHA does not support its conclusions.

In the draft decision, the AER indicated that SAHA relied on information from the CIE to calculate the costs associated with a major bushfire ignited by TransGrid's own assets. The AER identified a number of issues associated with the use of this information by SAHA including that the functional relationship between damage costs and area burnt proposed by CIE could not be relied upon.[653]

SAHA responded by indicating that it did not use the costs identified in the CIE report to determine damage area.[654]

The AER notes that SAHA did not indicate that it used the costs in the CIE report, rather that SAHA used the functional relationship in the CIE report to establish costs for TransGrid.[655] As indicated in the draft decision, and confirmed by SAHA in its response to the draft decision[656], SAHA used the functional relationship from the CIE report to establish:

- the value of minor bushfires (and from this the ratio of major to minor bushfires)
- the average hectares of land burnt during a minor and major bushfire.

SAHA then applied the average hectares of land burnt during a minor and major bushfire to TransGrid's average value of assets per square kilometre to determine the value of damage caused by a minor or major bushfire.[657]

---

651 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.
652 Further, it is not clear that this bushfire was caused by distribution assets rather than transmission assets.
653 AER, *Draft decision*, pp. 288–289.
654 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.
655 AER, *Draft decision*, p. 288.
656 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.
657 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.

Clearly, if the functional relationship developed in the CIE report is not robust, then the value of damage caused by a minor (or major) bushfire calculated by SAHA (based on this functional relationship), cannot be relied upon. As indicated in the draft decision, the AER identified a number of issues with the functional relationship derived in the CIE report. In particular:

- based on an examination of the historical data underpinning the CIE modelling, the AER is unable to unambiguously match the values provided in the CIE report with those in the base data[658]
- for those values that can be identified, it appears that the damage costs used by CIE to forecast the relationship have not been converted to constant dollars. As such, the observations are not comparable over time[659]
- the explanatory power of the proposed CIE functional relationship is poor. The coefficient of determination is reported as 0.39, implying that only 39 per cent of the variation in bushfire damage cost can be explained by the amount of hectares burnt.[660]

Notwithstanding these issues, the AER notes that SAHA appears to have incorrectly applied the information in the CIE report in deriving the damage area associated with a major bushfire ignited by TransGrid's own assets. SAHA used the CIE report (the functional relationship) to derive the average hectares of land burnt during a major bushfire, indicating that a major bushfire would cause damage to 80 000 hectares.[661] However, the AER notes that the CIE report advises against the use of this relationship, stating that '(f)or other cost items, such as injuries, fatalities and damage from major events, it is more appropriate to base damage costs on event frequencies rather than areas burnt'.[662] Notwithstanding this point, the AER notes that if the CIE report was to be used for this purpose, the average area of land burnt by a major bushfire would be 800 000 hectares not 80 000 hectares as proposed by SAHA.[663]

In support of its cost calculations, SAHA provided additional information related to hectares burnt by major bushfires in Australia over the past 80 years.[664] SAHA stated that the information indicated that the area burnt by a major bushfire '…is more than 6 times the figure used for the quantification'[665]—that is, the 80 000 hectares derived from SAHA's analysis above. The AER notes that SAHA has not explained why this information differs so significantly from that derived by SAHA from the CIE report and relied upon to determine the costs associated with major bushfires. Further, SAHA has not indicated the source of this additional information and has not explained how it defined the major bushfires listed—SAHA previously used costs to define a major bushfire, but no cost information is provided.

658 This assessment is based on an examination of the data source in its current format. Given the historical nature of the data, the AER would not expect any deviation between this data set and that used by CIE over the observed timeframe. See: http://www.ema.gov.au/ema/emadisasters.nsf/webEventsByCategory?OpenView&Start=1&Count=30&Expand=1#1.

659 The AER notes that the CIE acknowledges this point and suggests, therefore, that the derived relationship is conservative.

660 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 113.

661 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.

662 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 110.

663 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 113.

664 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 34.

665 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 34.

SAHA also provided information from the Council of Australian Governments (COAG) report—*National Inquiry on Bushfire Mitigation and Management*—dated December 2004, which listed all the main bushfires that have occurred in each State and Territory in Australia. SAHA suggested that this data supported the damage areas calculated by SAHA (44 000 hectares and 80 000 hectares for minor and major bushfires respectively).[666] Similar to the previous additional information provided by SAHA, the AER notes that SAHA has not clarified how a major bushfire is defined in the data. Nor has SAHA explained the distinction between a minor and major bushfire provided in this additional information. It is therefore not possible from the additional information to determine the damage area associated with a major bushfire.

Based on the above assessment, the AER considers that it is not appropriate to use the CIE report as proposed by SAHA and furthermore, that even if the data were appropriate, SAHA has incorrectly interpreted the information in the CIE report to determine costs associated with a major bushfire ignited by TransGrid's own assets.

On this basis, the AER does not consider that the proposed self insurance premium for the risk of a major bushfire ignited by TransGrid's assets reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.

The AER notes that the information provided by SAHA is contradictory, making it difficult to determine the appropriate information to use in determining the costs associated with a major bushfire. While it may have been possible for the AER to refer to cost information in relation to the Appin fire in the Integral Energy network to estimate these costs, the AER notes that this cost information also utilises the CIE report. Accordingly, based on the information provided in the revenue proposal and the revised revenue proposal, the AER is unable to calculate a value for the self insurance premium.

Bushfires ignited by a third party

The self insurance premium for bushfires ignited by a third party consists of a premium for minor bushfires ($200 000) and a premium for major bushfires ($6000).

In its original report, SAHA noted that there is no history of a (minor or major) bushfire ignited by a third party impacting on TransGrid's network. However, SAHA suggested that the sheer number of minor bushfires per annum ignited by a third party—around 300 per year—indicated that there was a considerable chance that one such minor bushfire could cause damage to TransGrid's asset base.[667] Accordingly, SAHA suggested that it was reasonable to assume that TransGrid would be impacted by a minor bushfire incident caused by a third party once every 15 years.

In addition, SAHA used the information from the CIE report to determine the damage area associated with a minor (and major) bushfire and from that information and TransGrid's asset data, the costs associated with a bushfire ignited by a third party.

In the draft decision, the AER noted that the NSW bushfire data referred to by SAHA reflects bushfire incidents in only one year (2002−03) and represented one of the worst

666 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 34.
667 SAHA obtained this information from a 2002−03 NSW Rural Fire Services report.

bushfire seasons in NSW history.[668] Notwithstanding this issue, the AER considered that SAHA had not established a robust relationship between the incidence of bushfires in NSW and the adoption of the associated probabilities. The AER also identified issues associated with the use of the CIE report as previously discussed. As a result, the AER rejected the self insurance premium in relation to minor bushfires ignited by a third party.[669]

In response, SAHA defended the use of bushfire information from the NSW Rural Fire Services, indicating that it does not believe that the percentage of bushfires ignited by different sources (electrical power lines and third parties) is likely to change significantly, even when the data was from the worst bushfire season.[670]

The AER notes the above point, however, consistent with the draft decision, the AER considers that SAHA has not established a robust relationship between the incidence of bushfires in NSW and the adoption of the 1 in 15 year probability that TransGrid would be affected by such a fire. SAHA has provided no explanation concerning the relationship between bushfires in NSW and the potential for damage to TransGrid's assets. Further, there is no explanation of how the 1 in 15 year probability associated with damage to TransGrid's assets has been derived. The only discussion on this issue is provided in SAHA's original report where SAHA indicated that, despite no recorded incidents of asset damage caused by such fires, the number of third party fires suggests that '…it (is) reasonable to assume TransGrid will be impacted by a minor bushfire incident caused by a third party once every 15 years'.[671] SAHA has provided no further information to demonstrate that such an assumption is reasonable. Based on the limited information provided, the AER is unable to satisfy itself that such an assumption is reasonable.

In determining the costs associated with a minor bushfire ignited by a third party, SAHA used information from the CIE report. As discussed above, the AER identified a number of issues associated with the use of the information provided in the CIE report.

Further, the AER has identified issues associated with SAHA's application of the CIE report to determine the damage area associated with a minor bushfire. SAHA suggested that minor bushfires cause $58.5 million damage.[672] This value can be derived from the average annual area burnt by small to medium bushfires in Australia[673] and the functional relationship between damage costs and area burnt for major bushfires.[674] Based on this approach, the resultant value of $58.5 million represents the total cost associated with all minor bushfires in Australia in a single average year.

---

668 AER, *Draft decision*, p. 289.

669 AER, *Draft decision*, p. 290.

670 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 39.

671 SAHA, *TransGrid Self Insurance Risk Quantification*, confidential, p. 80.

672 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.

673 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, table 7.5, p. 112. Note the CIE indicates that these refer to small to medium bushfires i.e. minor bushfires. See CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 108.

674 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, chart 7.7, p. 113. The cost function in the CIE report predicts a damage cost of $133 000 for every 1 000 hectares burnt by wildfire. According to the CIE report, the average annual area burnt by small and medium bushfires in Australia = 440 000 hectares. Hence the damage cost = 440 × $133 000 = $58.5 million.

SAHA used this value to determine a ratio of major to minor bushfires.[675] SAHA then used this ratio to derive damage associated with a single minor bushfire—SAHA indicated that a single minor bushfire would damage 44 000 hectares.[676]

However, the AER notes SAHA has incorrectly used 80 000 hectares as the amount of area burnt by a major bushfire (rather than 800 000 hectares[677]) and that the ratio derived by SAHA actually represents all minor bushfires in a single year in Australia rather than a single bushfire and therefore cannot be used to calculate the damage associated with a single minor bushfire.[678]

Based on the above, the AER is not satisfied that the premium associated with minor bushfires caused by third parties reflects the efficient costs of a prudent operator in the circumstances of TransGrid to achieve the opex objectives and rejects the self insurance premiums.

The AER is unable to develop an alternative probability for such bushfires or to determine an appropriate average cost, based on the lack of supporting information provided in the revenue proposal and the revised revenue proposal.

In the case of a major bushfire ignited by a third party, SAHA used the CIE report to derive the probability of a major bushfire in NSW. SAHA combined this information with the previously derived probability of a third party causing a bushfire incident in NSW—that is, 1 in 15 years—to calculate the probability of a major bushfire being ignited by a third party in NSW. SAHA used the information from the CIE report and TransGrid's asset data to determine the cost associated with a major bushfire ignited by a third party.

In the draft decision, the AER did not accept the self insurance premium associated with a major bushfire ignited by a third party on the basis that:

- the proportion of major bushfires accounted for in NSW (from the CIE report) appears to relate to minor rather than major bushfires as proposed by SAHA[679]
- SAHA provided no explanation for the assumed probabilities of a minor bushfire incident caused by a third party impacting TransGrid
- SAHA's forecast costs were derived on the same basis as those for a major bushfire ignited by TransGrid's assets—that is, based on the CIE proposed relationship between damage costs and damage area. The AER noted that it had identified a number of issues associated with the functional relationship used by the CIE.

In its response, SAHA defended the use of data from the NSW Rural Fire Services for the 2002–03 year and provided further explanation on the use of the CIE report in developing the cost forecasts (as discussed above).[680]

675 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.
676 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.
677 See the section on major bushfires ignited by a DNSPs own assets for a discussion of this value and its appropriateness to the analysis.
678 The AER notes that, using the ratio in its corrected format results in a final value for area burnt by all minor bushfire in Australia of 440 000 hectares (consistent with the value provided in table 7.5 of the CIE report).
679 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 108 and table 7.5.
680 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 39.

The AER maintains that the proportion of major bushfires accounted for in NSW (from the CIE report) appears to relate to minor bushfires. It is not clear to the AER that this same proportion can be applied to the incidence of major bushfires. Notwithstanding this issue, the AER considers that SAHA has not established a robust relationship between the incidence of bushfires in NSW and the adoption of the 1 in 15 year probability that TransGrid would be affected by such a fire. Further, as discussed above, the AER has identified issues associated with the use of the CIE report in developing cost estimates associated with a major bushfire.

On the basis of this analysis, the AER concludes that it is not satisfied that the self insurance premiums associated with minor and major bushfires caused by third parties reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute efficient premium for this risk due to the lack of supporting information provided in the revenue proposal and the revised revenue proposal.

Summary

The AER maintains its draft decision and does not accept the self insurance allowances for TransGrid for minor and major bushfires caused by TransGrid's own assets or a third party. Accordingly, the AER has reduced TransGrid's proposed self insurance allowance for bushfires from $267 000 per annum to $3000 per annum.[681]

Towers, lines and cables

This category of self insurance covers the cost of damage to towers, lines and cables from an exogenous event (other than earthquake, bushfire, terrorism and impact of aircraft). Damage in this category is generally caused by events such as storms, falling trees and ground subsidence affecting cables.

The proposed self insurance premium for damage to TransGrid's towers, lines and cables is $1.3 million per annum. This self insurance premium includes amounts for towers and wires ($208 000), conductors ($172 000), underground cables ($918 000) and an amount for third party damage ($12 000).

In the draft decision, the AER accepted the premiums associated with towers and wires ($208 000) and conductors ($172 000), but rejected the self insurance premiums in relation to damage to underground cables and third party damage.[682]

In the draft decision, the AER noted that SAHA's self insurance premium for damage to underground cables relied upon two historical observations over a four–year period with a cost of $4309 for one incident involving a low voltage cable and $3.7 million for the other relating to damage to a high voltage cable.[683] SAHA assumed the cost of a future underground cable incident to be the average of these two observations, that is, $1.8 million.

681 $267 000 less $50 000 for minor bushfires ignited by TransGrid's assets, less $8000 for major bushfires ignited by TransGrid's own assets, less $200 000 for minor bushfires ignited by a third party, less $6000 for major bushfires ignited by a third party.

682 AER, *Draft decision*, pp. 292–293.

683 AER, *Draft decision*, p. 292.

The AER rejected the premium on the basis that there were too few observations and too much variance in the costs associated with these observations for a reasonable future cost estimate to be determined. The AER also noted that it was not clear that the costs associated with the larger of the two events have been incurred by TransGrid.[684]

In response, SAHA indicated that the period of observation is actually 13 years rather than the four years originally reported.[685] In addition, based on an inventory of TransGrid's underground cables, SAHA confirmed that the majority of underground cables are high voltage. As such, SAHA proposed to refine its original calculation, namely to focus its self insurance quantification on TransGrid's high voltage underground cables. SAHA suggested that such an approach is appropriate since these cables:

- are the most significant to TransGrid, in terms of its overall inventory of cables
- have the highest consequence when impacted by third parties
- are the most exposed to third parties.[686]

SAHA therefore recalculated the self insurance premium based on the revised time period (13 years) and based on the one high voltage underground cable incident over that period (resulting in a cost of $3.7 million).[687] Based on this calculation, SAHA proposed a revised self insurance premium for the risk of damage to high voltage underground cables of $284 615 per annum.

The AER is satisfied with the explanation provided by TransGrid and accepts the self insurance premium for damage to high voltage underground cables of $284 615 per annum.

TransGrid also sought self insurance in relation to third party damage as a result of damage to its towers and wires. TransGrid indicated that it had not experienced any third party claims in relation to damage to its towers and wires. Notwithstanding this, SAHA considered it reasonable to assume that once every 20 years, a large scale incident involving TransGrid's towers and lines could lead to consequential third party damage in excess of TransGrid's current $250 000 deductible.

In the draft decision, the AER rejected the claim for self insurance on the basis that SAHA has provided no information in support of its 1 in 20 year probability or the potential cost.[688]

In response, SAHA suggested that there is a real risk that such an event could occur and result in third party claims. SAHA further indicated that its probability assessment of 1 in every 20 years is reasonable, based on the fact that there have been numerous occurrences of towers collapsing in other jurisdictions.[689]

684 SAHA indicated that it had assumed that TransGrid self insures for underground cables and the cost of this incident is unrecoverable from (a) third party.

685 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 54.

686 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 55.

687 SAHA omitted the cost associated with the one low voltage underground cable incident ($4309).

688 AER, *Draft decision*, p. 292.

689 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 57.

The AER notes that, while the additional information provided by SAHA indicates that tower collapses have been recorded in other jurisdictions, SAHA has provided no information to indicate that these collapses resulted in third party claims. Further, while this risk may well exist for TransGrid, based on the limited information provided by SAHA, the AER is unable to accept that the 1 in 20 year probability adopted by SAHA is reasonable. SAHA has provided no rationale for the adoption of this particular probability or explained why the probability should be considered reasonable. The AER therefore rejects the associated self insurance premium on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to determine a self insurance allowance.

The AER notes that it is unable to derive a efficient substitute premium for this risk due to the lack of supporting information provided in the revenue proposal and the revised revenue proposal.

Summary

Based on the information provided, the AER maintains its draft decision and accepts the proposed self insurance premium associated with towers and wires ($208 000) and conductors ($172 000). In addition, based on SAHA's revised calculation, the AER accepts the self insurance premium for damage to high voltage underground cables of $284 615 per annum.

The AER maintains its draft decision and does not accept the self insurance allowance for TransGrid in relation to third party damage as a result of damage to TransGrid's towers and wires ($12 000).

In total the AER has reduced the self insurance premium for towers and wires from $677 000 million per annum[690] to $665 000 per annum.[691]

Key assets

TransGrid sought self insurance for costs associated with the failure of power transformers and circuit breakers, including consequential damage/liability to a third party's property as a result of failure of these assets.

In the draft decision, the AER accepted the self insurance premium for costs associated with the failure of power transformers and circuit breakers, but rejected the claim associated with third party claims.[692] The AER rejected the self insurance premium in relation to third party damage on the basis that the probability of occurrence had not been reasonably determined.[693]

In response, SAHA suggested that the AER rejected the self insurance allowance for third party claims on the basis that TransGrid had never experienced such an event.[694] SAHA indicated that it is difficult to quantify this risk, but believed that its probability and

---

690 Based on the revised values provided in: SAHA, *Response to the AER's Draft Decision – Self Insurance*.

691 $208 000 for towers and wires, $172 000 for conductors and $285 000 for high voltage underground cables.

692 AER, *Draft decision*, p. 293.

693 AER, *Draft decision*, p. 293.

694 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 47.

consequence estimates were reasonable, and moreover, that its estimates were more reasonable than a zero self insurance allowance as proposed by the AER.[695]

The AER notes that it did not reject the proposed premium on the basis of a lack of historical information, rather, the AER rejected the premium on the basis that there was no information provided in the revenue proposal on which to determine that the premium was reasonable. In its original report, SAHA's argument for the adoption of a 1 in 20 year probability for such an event consisted of a statement that, notwithstanding that there have been no previous claims:

> SAHA considers it reasonable to assume that such an incidence could occur, even if there is a low probability of occurrence. On balance, SAHA believes that assuming a 1 in 20 year probability of consequential third party damage occurring is reasonable.[696]

The AER agrees that this risk may well exist for TransGrid, however, based on the limited information provided, the AER is unable to accept that the 1 in 20 year probability adopted by SAHA is reasonable. SAHA has provided no rationale for the adoption of this particular probability.

In response to SAHA's argument that the calculated premium is more reasonable than the zero premium provided by the AER in the draft decision, the AER does not consider that this constitutes a sufficient rationale in support of the 1 in 20 year probability adopted by SAHA.

Based on the assessment above, the AER is not satisfied that the self insurance premium for third party claims arising from key asset failure reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute efficient premium for this risk due to the lack of supporting information provided in the revenue proposal and the revised revenue proposal.

Summary

The AER maintains its draft decision and does not accept the forecast self insurance allowance for TransGrid for third party claims arising from key asset failure. Accordingly, the AER has reduced the self insurance premium for key assets from $672 000 per annum to $660 000 per annum.

Contractual risk

This self insurance claim refers to a situation where the terms or conditions of a contract made between a third party and TransGrid exposes TransGrid to some residual risk—that is, TransGrid does not have mitigation mechanisms within the contract itself for a risk that would be reasonably expected to occur in relation to the provision of the service in question. The proposed self insurance premium for this risk is $11 500 per annum.

SAHA identified two scenarios of contractual risk for TransGrid:

---

695 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 47.
696 SAHA, *TransGrid Self Insurance Risk Quantification*, p. 100.

- the risk that a major design and construction contractor defaults, incurring transition costs
- the risk that TransGrid's current IT provider defaults, and as such, TransGrid incur unforseen transition costs when transferring to a new provider.

In the draft decision, the AER rejected the proposed self insurance premium. The AER considered that the onus was on TransGrid to ensure that the contractual arrangements between itself and a third party are sufficient to mitigate against contractual risk. To the extent this is not the case, the AER suggested that TransGrid, rather than its customers, should bear the associated costs.[697]

In response, SAHA indicated that the AER's decision implies that in every contract that TransGrid enters into, and for every conceivable risk within that contract, TransGrid is the party best placed to manage that risk.[698] In addition, SAHA indicated that, in certain circumstances, contractors or suppliers may place an excessive premium on bearing certain risks. In both of these situations, the cost to TransGrid of mitigating that risk within the contract may be greater than the cost to TransGrid of self insuring against that risk.[699]

Notwithstanding the above, SAHA indicated that its analysis only focussed on the probability of default and the cost of transitioning to a new contractor. SAHA suggested that implicit within the AER's decision to reject this risk is that:

- there is zero probability that a contractor or supplier will ever default on TransGrid
- even if they did default, there will always be a zero cost to TransGrid associated with engaging another contractor to do that work.[700]

The AER did not intend to imply that there is a zero probability of a contractor or supplier defaulting on TransGrid. Rather, the AER considers that the onus is on TransGrid to ensure that its contractual arrangements are sufficient to protect against contractor default. In relation to an example of costs TransGrid incurred due to a tunnelling contractor going into administration,[701] the AER would expect that such costs would be covered under the contractor's insurance. The AER expects that TransGrid would not engage a contractor without the contractor maintaining similar insurance arrangements. Further, it is not clear to the AER that costs involved in transitioning to a new contractor as a result of default would not also be covered by such insurance.

In relation to the cost associated with engaging another contractor, SAHA provided an example of voluntarily engaging (rather than as a result of default of a previous provider) an alternative IT provider and the consequent 'unforseen' transition costs.[702] While the AER accepts that transitioning costs were incurred, it is not clear to the AER that the 'unforseen' costs do not reflect a failure of the due diligence process in deciding to move from one provider to the next. If this were the case, it would not be appropriate for these costs to be covered under self insurance (since these are under TransGrid's control). In

697 AER, *Draft decision*, pp. 294–295.
698 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 57.
699 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 57.
700 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 58.
701 SAHA, *TransGrid Self Insurance Risk Quantification*, confidential, p. 107.
702 SAHA, *TransGrid Self Insurance Risk Quantification*, confidential, p. 107.

addition, SAHA has provided no evidence to support the claim that similar costs (i.e. $1 million) would again be incurred if the current IT provider was to default and TransGrid was forced to engage an alternative provider. Further, in the event that the current IT provider defaults, it is not clear to the AER that TransGrid would not be able to recoup transitioning costs as part of any legal claim against the defaulting business.

SAHA suggested that transitioning costs in the event of a contractor or supplier defaulting would be one per cent of the project value.[703] The AER notes that TransGrid has not provided details of transition costs incurred by TransGrid where a contractor or supplier has defaulted (or whether in fact there have been any such transitioning costs). Further, as mentioned above, it is not clear to the AER that such costs would not be recouped as part of any legal claim against the defaulting contractor or supplier.

Based on the above, the AER is not satisfied that the self insurance premium for contractual risk reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute efficient premium for this risk due to the lack of supporting information provided in the revenue proposal and the revised revenue proposal.

Summary

The AER maintains its draft decision and does not accept the forecast self insurance allowance for contractual risk for TransGrid. Accordingly, the AER does not accept the proposed self insurance premium of $11 500 per annum for TransGrid.

General public liability

General public liability risk covers incidents where TransGrid is liable for injuries or other losses suffered by member(s) of the general public as a result of its (or its employees) negligence or fault. TransGrid sought self insurance of $12 500 per annum in relation to general public liability for claims above the existing external insurance deductible.

In its original report, SAHA indicated that, while TransGrid had no experience with such events, SAHA considered it reasonable to assume that a large scale general public liability event, with a consequence in excess of TransGrid's current $250 000 deductible, could occur 1 in every 20 years.[704]

In the draft decision, the AER rejected the claim for self insurance on the basis that SAHA had not provided sufficient rationale for the proposed probability and cost estimates associated with general public liability risk.[705]

In its response to the AER, SAHA suggested that general public liability is a credible risk that could affect each business at some point in the future, and therefore should be included as a self insured risk premium.[706]

703 SAHA, *TransGrid Self Insurance Risk Quantification*, confidential, p. 108.
704 SAHA, *TransGrid Self Insurance Risk Quantification*, confidential, p. 112.
705 AER, *Draft decision*, p. 295.
706 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 50.

The AER has not concluded that TransGrid could never be exposed to such risks, but rather, has concluded that it cannot accept the self insurance premium based on the information provided. As previously discussed, the AER's role is not to identify potential risks faced by TransGrid, but is to assess the proposed operating costs (self insurance premiums). Accordingly, the AER is not concerned whether or not an event is possible, but rather, whether the premium is reasonable based on the evidence provided.

SAHA indicated that the 1 in 20 year probability of occurrence of such an event for TransGrid represented a discount on that applied to the NSW DNSPs given differences in the individual networks.[707] The AER notes that SAHA has suggested that the probability of occurrence of claims is a function of the size of a business' workforce and its exposure to the general public.[708] However, the AER notes that, if this were the case, it is not clear why Integral Energy would have experienced two such events in the past five years, while Country Energy and EnergyAustralia (with larger workforces and similar exposure to third parties) have experienced no events in 11 years. Similarly, on this basis, it is not clear how the 2 in 11 year probability applied to both Country Energy and EnergyAustralia can be reconciled to the Integral Energy experience.

The AER considers that, in seeking to apply the experience of Integral Energy to TransGrid, it is necessary for SAHA to identify the relevant risk factors inherent in TransGrid vis–à–vis Integral Energy, and explain the application of this relationship in developing the 1 in 20 year probability. In the absence of such information, it is not clear to the AER how the reasonableness of the resultant probability calculation can be verified.

Based on the above, the AER is not satisfied that the self insurance premium for general public liability for claims above the existing external insurance deductible reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute efficient premium for this risk due to the lack of supporting information provided in the revenue proposal and the revised revenue proposal.

Summary

The AER maintains its draft decision and does not accept the forecast self insurance allowance for general public liability risk for TransGrid. Accordingly, the AER does not accept the proposed self insurance premium of $12 500 per annum for TransGrid.

Failure to supply

This represents the risk that TransGrid will be unable to supply electricity to the NEM, or that it will be unable to make its network available to generators and will therefore be subject to a compensation claim. The self insurance premium proposed for this risk is

707 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 51. SAHA calculated a probability for general public liabilities claims for Country Energy and EnergyAustralia of 2 in 11 years based on claims in the Integral Energy network (2 in 5 years). SAHA suggested that, whilst neither Country Energy nor EnergyAustralia had experienced such an event, the 2 in 11 year probability represented a discount on the 2 in 5 year probability applied to Integral Energy.

708 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 51.

$19 000 per annum ($2500 associated with below deductible claims and $16 500 associated with above deductible claims).

SAHA identified 3 below deductible events that were the responsibility of TransGrid. Further, SAHA indicated that the cost in claims for each of these has been less than $5000. SAHA indicated that TransGrid had not recorded any failure to supply incident that resulted in a cost above the deductible. However, SAHA considered it reasonable to assume at least 1 occurrence of an above deductible failure to supply incident every 15 years.

In the draft decision, the AER rejected the self insurance claim for failure to supply. The AER noted that no information concerning the period over which the 3 below deductible events occurred was provided and SAHA provided no information in support of the 1 in 15 year probability applied to above deductible claims.[709]

In response, SAHA indicated that the 3 below deductible events occurred in the current regulatory control period. As a consequence, SAHA applied a probability of 1 in 2 years.[710] Based on this information (and the associated historical cost of claims), the AER accepts the proposed self insurance premium associated with below deductible claims of $2500 per annum.

SAHA indicated that TransGrid had not recorded any failure to supply incident that resulted in compensation claims above the deductible.[711]

While SAHA acknowledged that the data set is not long enough to ascertain the probability with a high degree of certainty, SAHA believed that the AER's approach of adopting a zero self insurance risk allowance for such risks was unlikely to reasonably reflect the efficient costs that a prudent operator would incur.[712]

The AER does not deny that such an event is possible, rather, under the requirements of the NER, the AER concluded that it could not accept the self insurance premium based on the information provided. Similarly, based on the lack of supporting information provided in the revenue proposal, the AER was unable to determine an alternative value.

SAHA indicated that, while TransGrid had not recorded any major incidences of failure, there are a number of incidences throughout Australia, and abroad that have occurred. SAHA identified 3 events from New Zealand, Victoria and Queensland and suggested that these examples show that there is a likelihood that similar events may occur in NSW.[713] SAHA noted that all three events have occurred within the last 10 years, implying that SAHA's original estimation of the probability of 1 in 15 years applied to TransGrid 'reasonably reflects' a logical estimation of such an event's occurrence.

The AER notes that the additional information provided does not indicate whether compensation claims were made in relation to these incidents. Notwithstanding this, the AER considers that, in seeking to apply the experience of other businesses to TransGrid, it is necessary to identify the relevant risk factors inherent in TransGrid vis–à–vis these

709 AER, *Draft decision*, p. 295.
710 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 60.
711 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 59.
712 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 59.
713 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 60.

other businesses, and explain the application of this relationship in developing the 1 in 15 year probability. In the absence of such information, it is not clear to the AER how the reasonableness of the resultant probability calculation can be verified.

Based on the above, the AER is not satisfied that the self insurance premium for claims above the existing external insurance deductible resulting from failure to supply reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute efficient premium for this risk due to the lack of supporting information provided in the revenue proposal and the revised revenue proposal.

Summary

The AER accepts the proposed self insurance premium associated with below deductible claims of $2500 per annum. However, the AER maintains its draft decision in relation to claims above the insurance deductible and does not accept the associated forecast self insurance allowance. Accordingly, the AER has reduced the self insurance premium for claims associated with failure to supply from $19 000 per annum to $2500 per annum.

Risks which should be treated as pass through events

The AER considers that there are a number of risks proposed by TransGrid that would best be accommodated through a cost pass through mechanism rather than through self insurance. For a number of risks, including earthquakes above magnitude six and major bushfires the AER notes that it is particularly difficult to derive a self insurance premium because of the low frequency of these events and the potential for catastrophic losses. The recent Victorian bushfires provide ample evidence of the potential for catastrophic losses to network businesses associated with such events.

While the AER considers that such events may typically be accommodated through a cost pass through mechanism, the AER notes that the pass through arrangements in chapter 6A of the NER do not provide for such force majeure events to be included.

Administrative arrangements

The AER notes that TransGrid's current administrative arrangements for self insurance were approved by the ACCC in the 2005 revenue cap decision. In line with accounting treatment, TransGrid incorporates self insurance expense within the opex line as part of overall opex for the year in its regulatory accounts.[714] TransGrid also discloses in its statutory accounts the main area of self insurance where it considers it is cost effective to carry the risk internally.

The AER notes that self insurance events are similar in nature to contingent liabilities which are defined under Australian Accounting Standards Board 137 *Provisions, Contingent Liabilities and Contingent Assets* (AASB 137) as a possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non occurrence of one or more uncertain future events not wholly within the control of an entity.[715] The standard describes contingent liabilities as liabilities that are not recognised

[714] TransGrid, *Response to issue number 331*, confidential, 16 March 2009.
[715] AASB 137 *Provisions, Contingent Liabilities and Contingent Assets*, paragraph 10.

as they are either a possible obligation which is yet to be confirmed or a present obligation which cannot be reliably estimated or is not probable.[716]

AASB 137 does not require that contingent liabilities are recognised,[717] but it does require that certain disclosures are made in the financial accounts of the entity which are responsible for bearing the risk of these liabilities.

As part of the administrative arrangements for self insurance, the AER considers it is prudent practice for a TNSP to disclose self insurance events each regulatory year and provide a brief description of the nature of the self insurance event in accordance with AASB 137. The standard also requires, where practical, disclosure of:

- an estimate of the financial effect of the liability
- an indication of the uncertainties relating to the amount or timing of the outflow
- the possibility of any reimbursement.[718]

The AER expects TransGrid to continue with its disclosure practice over the next regulatory control period, including further disclosure on other material risks it has self insured for.

AER conclusion

For the reasons set out above, the AER considers that the proposed self insurance allowances do not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to meet the opex objectives. Accordingly, under clause 6A.6.6(d) of the NER, the AER has not accepted the forecast self insurance allowances. Further, consistent with the requirements of clause 6A.14.1(3)(ii) of the NER, the AER has provided substitute values for the associated self insurance premiums.

For the reasons discussed and as a result of the AER's analysis of the revised revenue proposal, the AER is satisfied that the amended estimate of the total self insurance allowance for the next regulatory control period set out in table D.1, based on the above accepted self insurance premiums and substitute values, reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

Table D.1: AER conclusion on self insurance allowance for TransGrid ($m, 2007−08)

	Revised revenue proposal	AER final decision
Total self insurance	11.0	9.2

716 AASB 137, paragraph 13(b).
717 AASB 137, paragraph 27.
718 AASB 137, paragraph 86.

Appendix E: Benchmark debt and equity raising costs

The AER concurrently assessed the revised revenue proposals of two TNSPs (TransGrid and Transend) and the revised regulatory proposals of four DNSPs (ActewAGL, Country Energy, EnergyAustralia and Integral Energy). Within this appendix these six regulated businesses are collectively referred to as the network service providers (NSPs). For convenience, within this appendix the term regulatory proposal should be taken to include the term revenue proposal, where the AER is referring to the NSPs. Within this appendix the AER has also used the term draft decision to refer to any and all of the relevant draft decisions affecting the NSPs. Where it has been necessary to refer to a draft decision for just one of the NSPs, within this appendix the AER has identified the specific business when referencing the draft decision, rather than applying the generic term draft decision, as defined in the shortened forms.

Debt raising costs

Rationale for joint consideration

The NSPs have proposed the same unit rate to determine the allowance for debt raising costs, a total of 15.5 basis points per annum (bppa) to be applied to the debt component of the regulatory asset base (RAB) each year.[719] This total unit rate is comprised of 3.0 bppa for indirect debt raising costs and 12.5 bppa for direct debt raising costs.

The shared position of the NSPs is reinforced by reliance on substantially the same consultant reports. In the regulatory proposals submitted by five of the six NSPs (excluding ActewAGL), variants of a Competition Economists Group (CEG) consultancy report were submitted.[720] In the revised regulatory proposals, a report by CEG is referenced and submitted by all six NSPs—that is, all submitted versions are identical.[721] TransGrid and EnergyAustralia both submitted an additional report by Tony Carlton, from the University of NSW, although there are some variations between the two versions.[722] Further, EnergyAustralia's submission requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and

---

719 TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 107; Integral Energy, *Revised regulatory proposal*, p. 43; and ActewAGL, *Revised regulatory proposal*, p. 33.

720 CEG, *Nominal Risk Free Rate, Debt Risk Premium and Debt and Equity Raising Costs for TransGrid*, May 2008; CEG, *Nominal Risk Free rate and Debt and Equity Raising Costs for Transend*, May 2008; CEG, *Nominal Risk Free Rate, Debt Risk Premium and Debt and Equity Raising Costs for Country Energy*, May 2008; CEG, *Nominal Risk Free Rate, Debt Risk Premium and Debt and Equity Raising Costs for EnergyAustralia*, May 2008; CEG, *Nominal Risk Free Rate, Debt Risk Premium and Debt and Equity Raising Costs for Integral Energy*, April 2008.

721 CEG, *Debt and Equity Raising Costs: A response to the AER 2008 draft decisions for electricity distribution and transmission*, January 2009. Cited by TransGrid, *Revised revenue proposal*, p. 77; Transend, *Revised revenue proposal*, p. 57; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 105; Integral Energy, *Revised regulatory proposal*, p. 43 and ActewAGL, *Revised regulatory proposal*, p. 33.

722 Carlton, T., *Indirect Costs of Equity and Debt Raising: Report prepared for EnergyAustralia*, 12 January 2009; and Carlton, T., *Indirect Costs of Equity and Debt Raising: Report prepared for TransGrid*, 12 January 2009.

revised regulatory proposal be considered by the AER in making its final determination for all the NSPs.[723]

Other relevant submissions were also received by the AER, from the following organisations:

- TransGrid—a report by the Strategic Finance Group (SFG)[724]
- Powerlink—regarding aspects of the draft decision for TransGrid[725]
- Joint Industry Association (JIA)—including a report by CEG that merges parts of the May 2008 and January 2009 CEG reports with new analysis (note that this report was additionally submitted as an attachment to EnergyAustralia's revised regulatory proposal).[726]

Due to the consistency between the opex provisions of the NER under which the debt raising cost proposals are assessed, the NSPs' revised regulatory proposals and the supporting consultancy reports, the AER jointly assessed the debt raising costs of the NSPs. The AER's analysis and conclusions are contained in this appendix, which is reproduced in each of the AER's final decisions for the NSPs.

The AER considers that it is important for a consistent methodology to determine the appropriate allowance for benchmark debt raising costs to be applied in its final decisions for the NSPs.[727]

Rationale for draft decisions

In making the draft decisions, the AER's consideration of debt raising costs took account of the requirements of the NER. This includes the requirement that forecast opex for the NSPs reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant NSP would require to achieve the opex objectives.[728]

The draft decisions were consistent with the relevant parameter values specified in the NER, including that the benchmark firm maintains a 60 per cent gearing ratio and issues debt at a BBB+ credit rating.[729]

Using the parameters specified in the NER, the AER constructed a model of the methodology by which a benchmark firm issues debt. Throughout this appendix the benchmark firm is a reference to a benchmark efficient NSP that is a pure play regulated electricity network operating in Australia without parent ownership. Assumptions about how such a benchmark firm issues debt were stated in the draft decisions. For example:

---

723 EnergyAustralia, *Submission on other network service providers*, 16 February 2009.
724 SFG, *Debt and equity issuance costs for a benchmark transmission business*, 20 March 2009.
725 Powerlink, 16 February 2009.
726 JIA, *Network Industry Submission: Debt and Equity Raising Costs*, 11 November 2008 and CEG, *Debt and equity raising costs: A report for the APIA, ENA and Grid Australia*, 11 November 2008.
727 This approach is essentially the same as that employed by the AER for its draft decisions.
728 For DNSPs, see clause 6.5.6(c)(2) of the transitional chapter 6 rules. For TNSPs, see clause 6A.6.6(c)(2)of the NER.
729 AER, *TransGrid draft decision*, p. 137; AER, *Transend draft decision*, p. 190; AER, *NSW DNSP draft decision*, p. 186 and AER, *ACT draft decision*, p. 107.

- the benchmark firm was assumed to issue public debt in the Australian market, in order to maintain consistency with the domestic capital asset pricing model (CAPM) that is applied to determine the regulated rate of return.[730]
- the debt was assumed to be raised in order to fund organic growth, rather than acquisitions or non–core investments, as the benchmark firm does not undertake such activities.[731]

The NSPs challenged the AER's assumption regarding the issuance of public debt in the Australian market and consistency with the domestic CAPM framework in their revised regulatory proposals. This is discussed below. Other assumptions (stated above) made by the AER in its modelling of the benchmark debt issue were not challenged by the NSPs, and accordingly, the AER considers that these assumptions remain valid for this final decision.

Indirect costs of debt raising

The AER rejected the proposed 3 bppa allowance for indirect debt raising costs (also known as underpricing) in the draft decisions.[732] All of the NSPs rejected the draft decision on this issue and resubmitted[733] the 3 bppa indirect cost allowance in their revised regulatory proposals.[734] The NSPs referred to consultant reports submitted as part of their revised regulatory proposals to justify the claim for indirect costs of debt raising.

Interpreting the NER prescribed BBB+ credit rating

The AER notes that the NER specifies:[735]

> The debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the 10 year commonwealth annualised bond rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity of 10 years and a credit rating of BBB+ from Standard and Poor's.

730 AER, *TransGrid draft decision*, p. 137; AER, *Transend draft decision*, p. 191; AER, *NSW DNSP draft decision*, p. 186 and AER, *ACT draft decision*, p. 105.

731 AER, *TransGrid draft decision*, p. 136; AER, *Transend draft decision*, p. 188; AER, *NSW DNSP draft decision*, p. 185 and AER, *ACT draft decision*, p. 105.

732 AER, *TransGrid draft decision*, pp. 137–138; AER, *Transend draft decision*, pp. 189–190 and AER, *NSW DNSP draft decision*, pp. 185–187. Note that indirect costs were not included as part of the original ActewAGL proposal, and so were not rejected in the ACT draft decision.

733 In the case of ActewAGL, this was not a resubmission but rather submission for the first time. The AER notes that the NER restricts the presentation of material in a revised regulatory proposal to matters addressed in the draft decision, and that this would ordinarily prevent ActewAGL from making such a methodological shift between regulatory proposal and revised regulatory proposal. However, the AER considers that regulatory consistency is paramount on this issue, such that the decision made for all other NSPs will be applied to ActewAGL as well.

734 TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 107; Integral Energy, *Revised regulatory proposal*, p. 43 and ActewAGL, *Revised regulatory proposal*, p. 33.

735 The clause cited here applies to DNSPs, see clause 6.5.2(e) of the transitional chapter 6 rules. For TNSPs, the relevant clause is almost identical; see clause 6A.6.2(e) of the NER: 'The debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the annualised nominal risk–free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a BBB+ credit rating from Standard and Poor's and a maturity equal to that used to derive the nominal risk–free rate.'

The AER observes this clause when it determines the debt risk premium associated with assumed debt issuance of the benchmark firm. To estimate the BBB+ benchmark corporate bond rate, the AER applies an established methodology based on the use of Bloomberg fair yield curves. CEG examined this methodology, and endorsed its use in its report accompanying the regulatory proposals:[736]

> In our opinion this approach is reasonable and the AER has shown that it does not result in a material error or an obvious bias (at least when measured against recent history).

CEG also tested the AER's methodology against an alternative approach and found the AER's methodology to be superior. In the draft decisions, the AER considered that the Bloomberg fair yield curves were therefore accepted as the best estimate of the cost of debt for the benchmark BBB+ debt issue.[737]

The AER notes that, in the revised regulatory proposals, issues have been raised in relation to the Bloomberg and CBASpectrum data sources used for establishing the debt risk premium. The AER's consideration of these issues is set out in section 4.5.2 of this final decision.

The AER notes that, although there is general agreement on the existence of direct costs of raising debt, CEG claim that additional indirect debt raising costs exist. CEG defined indirect costs in terms of underpricing, stating that:[738]

> Underpricing is a cost to all businesses who, in order to ensure the success of a debt issue, need to issue debt at a discount to the price it subsequently trades. This is true for all firms irrespective of their credit rating.

This explanation for underpricing—that it is required to sell debt—was explicitly mentioned by the NSPs in their revised regulatory proposals.[739]

For debt issues, CEG stated that there is a simple relationship between yield and price:[740]

> In the case of debt, a lower price implies a higher interest rate.

The AER further notes that Associate Professor Handley highlighted the key issue that distinguishes debt underpricing from equity underpricing:[741]

> …if a firm issues debt securities at a discount to the fair market price then there is a [sic] immediate gain to the new investors (who acquire the securities at a lower price) and an immediate cost to the firm in the form of lower proceeds received from the issue. In other words, unlike with equity securities, the higher the underpricing the lower the proceeds raised at the time of issue.

---

736 CEG, May 2008 (TransGrid), p. 7, paragraph 13; CEG, May 2008 (Transend), p. 7, paragraph 14; CEG, May 2008 (Country Energy), p. 7, paragraph 14; CEG, May 2008 (EnergyAustralia), p. 4, paragraph 14 and CEG, April 2008 (Integral Energy), p. 7, paragraph 13.

737 AER, *TransGrid draft decision*, pp. 93–94; AER, *Transend draft decision*, pp. 150–151; AER, *NSW DNSP draft decision*, pp. 225–226 and AER, *ACT draft decision*, pp. 137–138.

738 CEG, January 2009, p. 45, paragraph 150.

739 For example, see EnergyAustralia, *Revised regulatory proposal*, p. 106 and TransGrid, *Revised revenue proposal*, p. 78.

740 CEG, January 2009, p. 44, paragraph 149.

741 Handley, J. C., *A note on the costs of raising debt and equity capital*, 12 April 2009, p. 15.

That is, Associate Professor Handley considered that if such underpricing exists, it will be included in measures of yield, in the manner of all other costs of debt. The AER therefore considers that the key issue is whether its approach to estimating the cost of debt for the benchmark regulated firm encapsulates the 'underpricing' effects.

The AER considers that the use of fair yield curves represent the best estimate of the expected cost of debt. Systematic underpricing, such as that proposed by CEG as applying to all firms irrespective of credit rating, should be readily detected and included in the fair yield curves. The AER considers that on these grounds, no allowance for underpricing is justified, taking into account the views of Associate Professor Handley:[742]

> In summary, assuming allowed revenues are determined using an appropriate estimate of the cost of debt, and noting that both the AER and CEG believe this to be the case, then it is my view that, underpricing should not be allowed as a cost of raising debt capital.

This is consistent with the draft decisions, which stated that:[743]

> If firms effectively issue at a higher yield than BBB+, for example due to underpricing the debt, the firms are effectively issuing higher yielding lower grade debt. The proposed underpricing premium is therefore inconsistent with the assumed BBB+ benchmark.

The AER considers that granting an indirect cost allowance on top of an efficient benchmark measure of the BBB+ cost of debt would be double counting, and systematically allowing a higher rate of return than that required by the NER. Accordingly, the AER considers that to the extent indirect debt raising costs represent a rate of return in excess of NER requirements, the proposed allowance for indirect debt raising costs is inappropriate.

Absence of supporting empirical evidence

TransGrid stated that there is a 'significant body of empirical evidence demonstrating that underpricing is a cost to businesses raising debt.'[744] CEG stated in similar terms that:[745]

> The finance literature we have referred to has demonstrated that the answer to this empirical question is that underpricing does exist. **This empirical fact cannot be assumed away**. [emphasis in original]

The AER does not consider that the NSPs or their consultants on this issue (SFG,[746] Carlton and CEG) have submitted reliable evidence that debt underpricing exists.

SFG discussed conceptual issues relating to indirect equity raising costs at length, and then argued that these reasons 'apply equally to the issuance of debt and equity

742 Handley, April 2009, p. 17.
743 AER, *TransGrid draft decision*, p. 137; AER, *NSW DNSP draft decision*, p. 186; and AER, *Transend draft decision*, p. 190.
744 TransGrid, *Revised revenue proposal*, p. 78.
745 CEG, January 2009, p. 45, paragraph 150.
746 The AER notes that the SFG report was received on 21 March 2009, more than one month after submissions closed on 16 February 2009. In this instance, the AER was able to consider all material within the SFG report on debt raising costs despite the late submission of this report. However, the AER notes that it has the right to reject late submissions, particularly where there is insufficient time to afford due consideration to the arguments therein.

capital'.[747] The AER considers that such a claim is not supported, in that the mechanistic difference between equity raising and debt raising is sufficient to invalidate such a combined approach.[748] The AER observes that for empirical measures of the cost of raising debt, SFG referred directly to the CEG report, and provided no independent analysis.[749]

Carlton noted several theoretical reasons for indirect debt raising costs. He also mentioned two research papers on the subject, and argued that there are differences between the US and Australian debt markets.[750] However, the CEG reports encompass all of Carlton's arguments, and present greater detail on most aspects. The AER therefore considers that thorough consideration of the CEG reports adequately addresses the issues covered by Carlton.

CEG's argument on indirect debt raising costs relied on a working paper by Saunders, Palia and Kim.[751] The authors of this paper do not find empirical evidence of underpricing in debt issues, stating:[752]

> …given the difficulty of generating one–day returns [a measure of underpricing] for a sufficient number of debt IPOs [initial public offerings], we did not directly calculate one–day returns.

That is, Saunders et al did not examine the existence of debt underpricing, as they did not possess the data to investigate this question.

The AER notes that Saunders et al referred to an earlier paper, by Datta, Datta and Patel as an anecdotal aside on debt underpricing.[753] CEG cited the Saunders et al working paper in its first report, stating:[754]

> Nevertheless, for a very small sample of 50 firms, Datta, Datta and Patel (1997) estimate first day returns on corporate debt to be close to zero (0.15%).

This 15 basis point return is the foundation of CEG's suggestion of an allowance of 3.0 bppa for indirect costs (spread across the life of a 5–year bond). The AER notes that the Saunders et al working paper also states:[755]

> Datta, Datta and Patel (1997) show in a small sample of 50 firms that first day (short term) returns on corporate bond issues were **insignificantly different from zero**. [emphasis added]

747 SFG, March 2009, p. 12.
748 This point is also made by Handley, April 2009, p. 4.
749 SFG, March 2009, p. 17.
750 Carlton, January 2009 (EnergyAustralia), pp. 32–33 and Carlton, January 2009 (TransGrid), pp. 39–41.
751 Kim, D., Palia, D., and Saunders, A., *The Long–Run Behaviour of Debt and Equity Underwriting Spreads*, Draft Paper, January 2003.
752 Kim, Palia and Saunders, January 2003, p. 5.
753 Datta, S., Iskandar–Datta, M. and Patel, A. *The Pricing of Initial Public Offers of Corporate Straight Debt*, Journal of Finance, Vol. 52(1), March 1997, pp. 379–396.
754 CEG, May 2008 (TransGrid), p. 20, paragraph 63; CEG, May 2008 (Transend), p. 20, paragraph 64; CEG, May 2008 (Country Energy), p. 20, paragraph 63; CEG, May 2008 (EnergyAustralia), p. 15, paragraph 57 and CEG, April 2008 (Integral Energy), p. 20, paragraph 63.
755 Kim, Palia and Saunders, January 2003, p. 3, footnote 2.

This quote refers to analysis by Datta et al, using the standard statistical methodology to investigate the significance of a data point, which concluded that the first–day returns were equivalent to zero. Datta et al did not find empirical evidence of underpricing for debt issues.

Alternative empirical evidence presented by CEG included a paper by Cai, Helwege and Warga.[756] This paper found that offerings[757] of investment grade bonds (those rated BBB or better) demonstrate overpricing of 1 basis point—that is, the lender pays a premium, lowering the rate of interest paid by the borrower.[758] Cai et al did, however, find underpricing for high–yield, speculative grade bonds (those rated BB or lower, including unrated bonds) of 14.9 basis points. CEG argued in its first report that BBB debt, being at the 'edge of investment grade', would be more underpriced than the average investment grade debt and therefore lie somewhere between 0 and 14.9 basis points.[759]

In the draft decisions, the AER stated that there was no evidence that such a trend existed.[760] If such a trend was present, Cai et al would likely have detected it via regression analysis. However, the study did not present such analysis.

In the CEG report, submitted by the NSPs with their revised regulatory proposals, CEG responded to the draft decision on this issue by repeating two points made in the May 2008 CEG report.[761]

First, CEG cited the Livingston and Zhou (2002) finding that BBB rated private debt is issued at a higher yield (measured by the spread over Treasury bonds) than public debt.[762] The AER considers this does not provide a strong rationale for consideration of the existence of underpricing. The existence of a different yield between private and public debt neither confirms nor denies the existence of underpricing when issuing either form of debt.

Second, CEG referred to its earlier statement regarding the Cai et al paper. CEG offered that the 'common sense observation that the lower a firm's credit rating the harder it will be to market new debt issues because of the increasing uncertainty associated with the value of that debt'.[763] The AER considers that there are other equally plausible explanations consistent with the observed data that do not involve the existence of

[756] Cai, N., Helwege, J., and Warga, A. (2007) *Underpricing in the Corporate Bond Market,* The Review of Financial Studies I, 20(5), pp. 2021–2046.

[757] The figures quoted here are for non–initial offerings of debt—that is, all debt offerings excluding the very first offering of debt by a firm. Although Cai et al also investigated (and separately report) initial offerings, CEG did not consider that these findings were relevant to the benchmark firm. The AER agrees that non–initial debt is the appropriate data point for consideration.

[758] CEG, May 2008 (TransGrid), p. 20, paragraph 65. Note that the overpricing is incorrectly reported by CEG as .01 of a basis point, rather than 1 basis point. See also CEG, May 2008 (Transend), p. 20, paragraph 66; CEG, May 2008 (Country Energy), p. 20, paragraph 65; CEG, May 2008 (EnergyAustralia), p. 16, paragraph 59 and CEG, April 2008 (Integral Energy), p. 20, paragraph 65.

[759] CEG, May 2008 (TransGrid), p. 20, paragraph 66; CEG, May 2008 (Transend), p. 20, paragraph 67; CEG, May 2008 (Country Energy), pp. 20–21, paragraph 66; CEG, May 2008 (EnergyAustralia), p. 16, paragraph 60 and CEG, April 2008 (Integral Energy), pp. 20–21, paragraph 66.

[760] AER, *TransGrid draft decision* p. 137; AER, *Transend draft decision*, p. 190 and AER, *NSW DNSP draft decision*, p. 186.

[761] CEG, January 2009, pp. 45–46, paragraphs 151–154 (which cite paragraphs 56 and 66 of the May 2008 (TransGrid) CEG report).

[762] CEG, January 2009, p. 45, paragraph 152.

[763] CEG, January 2009, pp. 45–46, paragraphs 153–154.

underpricing of BBB grade debt. For example, it may be that the uncertainty of debt value increases dramatically once the investment/speculative threshold is crossed, but remains constant prior to reaching this threshold. Alternatively, it may be that the higher compensation provided by the direct yield of lower rated debt offsets the increased debt marketing difficulties, such that no indirect cost is incurred. In other words, a higher yield may be sufficient to attract investors to lower grade debt.

The AER does not consider the material cited by CEG in support of this argument to be empirical evidence. The interpolation of bond underpricing between investment grade bonds and speculative grade bonds assumes a known relationship between credit ratings and issuance prices relative to the face value of the debt issued. No theoretical basis or empirical evidence has been provided by CEG to support this relationship. Accordingly, the AER maintains its position that adequate empirical evidence on BBB underpricing has not been provided by the NSPs, within their regulatory proposals, revised regulatory proposals or associated consultant reports.

Finally, the AER considers there are substantial problems with concluding that the benchmark firm issuing debt in Australia will incur underpricing costs, on the basis of an overseas study. No evidence that BBB+ debt is sold (on average) at a discount in Australia has been provided to support the NSPs' arguments on underpricing. The NSPs have argued that there are significant differences between debt raising costs in the United States and Australia, and that the debt raising costs in the United States were lower than in Australia. For example, EnergyAustralia stated:[764]

> It is more than likely that the cost of raising debt in the US is lower than the cost of raising debt in Australia because of the depth of the US financial market. This is consistent with [sic] recent paper by Bortolotti, Megginson and Smart (cited in the Carlton report) which found that the US has the lowest cost of raising equity in the world.

The AER does not consider that the Bortolotti et al paper, which deals solely with equity raising costs, is relevant to debt raising costs.[765] Further, the AER does not consider that Carlton provided any empirical evidence of debt underpricing in Australia, but instead presented anecdotal statements from market practitioners that the Australian market is illiquid and therefore a more expensive place to issue debt.[766] Carlton also stated:[767]

> Anecdotally we would consider that foreign issuers would pay a premium; the "first time issuers" premium of 6 bp per annum to 12 b.p. [sic] per annum may be a useful estimate of this premium.

The AER notes that there is no empirical support for the existence of a foreign issuer premium, or that it would be equivalent to a first–time issuer premium. Most importantly, the AER notes that the Carlton report does not present empirical evidence of underpricing on Australian debt, or empirical evidence of a relationship between Australian and US debt raising costs.

764 EnergyAustralia, *Revised regulatory proposal*, p. 106. A similar statement is made in TransGrid, *Revised revenue proposal*, p. 42, paragraph 141.

765 Bortolotti, B., Megginson, M. and Smart, S., *The Rise of Accelerated Seasoned Equity Underwritings,* Journal of Applied Corporate Finance, 2008, vol. 20(3), pp. 35–57.

766 Carlton, January 2009 (EnergyAustralia), pp. 32–33; and Carlton, January 2009 (TransGrid), p. 40.

767 Carlton, January 2009 (EnergyAustralia), p. 33; and Carlton, January 2009 (TransGrid), p. 40.

The AER has not 'assumed away' empirical evidence. Rather, the empirical evidence presented by the NSPs and their consultants does not support the claims made. The AER considers that it has not been provided with empirical evidence of debt underpricing for BBB+ rated bonds in any country, or evidence of debt underpricing in Australia.

Relationship between indirect and direct debt raising costs

The NSPs submitted that the direct and indirect debt raising costs are interdependent and cannot be considered in isolation.[768] TransGrid stated that an increase in direct debt raising costs leads to a decrease in indirect debt raising costs, and vice versa.[769] The key argument made by CEG for this substitutability is that direct debt raising costs are related to the marketing of the debt—if the debt itself becomes cheaper (via an increase in indirect cost), then it is easier to sell and marketing costs will drop.[770]

While several studies were cited by CEG for equity issues, the AER considers that no conclusive empirical evidence was presented linking direct and indirect debt raising costs for BBB+ debt.

The AER notes that when the Saunders et al working paper (which formed the basis of much of the CEG report on this issue) was accepted for publication in 2008, all comments regarding underpricing had been removed.[771] The explanation offered by Saunders et al is as follows:[772]

> An analysis of the relationship between direct and indirect costs is an interesting issue. It is plausible that issuers and underwriters bargain over both the direct and indirect costs of issue, resulting in these two costs being jointly endogenously determined. However, difficulties in identifying suitable instrumental variables for IPOs, SEOs, and debt issues are significant enough that we leave tests of this relationship to future work.

This indicates that no empirical relationship had been established between these two cost categories by Saunders et al, which was the primary source of academic material cited by CEG.

In conclusion, the AER has considered the evidence presented by TransGrid and its consultants on the relationships between indirect and direct debt raising costs. The AER has not been provided with any peer–reviewed empirical evidence to support the claim that indirect and direct debt raising costs must be considered jointly. Moreover, the AER is mindful of the absence of evidence for indirect costs (as discussed above). On this basis, the AER considers there is no need to account for any interaction effects between indirect and direct debt raising costs.

---

768 For example, EnergyAustralia, *Revised regulatory proposal*, p. 107.

769 TransGrid, *Revised revenue proposal*, p. 78.

770 CEG, May 2008 (TransGrid), pp. 11–12, paragraphs 26–30; CEG, May 2008 (Transend), pp. 11–12, paragraphs 27–31; CEG, May 2008 (Country Energy), p. 11–12, paragraphs 26–30; CEG, May 2008 (EnergyAustralia), pp. 8-9, paragraphs 24–27 and CEG, April 2008 (Integral Energy), pp. 11–12, paragraphs 26–30.

771 Kim, D., Palia, D., and Saunders, A., *The Impact of Commercial Banks on Underwriting Spreads: Evidence from Three Decades*, Journal of Financial and Quantitative Analysis, December 2008, vol. 43(4), pp. 975–1000.

772 Kim, Palia and Saunders, December 2008, p. 977.

AER conclusion—indirect debt raising costs

The AER has considered the evidence presented by the NSPs and their consultants on indirect debt raising costs. In conclusion, the AER considers:

- an indirect cost allowance would be inconsistent with the BBB+ credit rating specified in the NER
- there is no empirical evidence to support the claim that BBB debt is underpriced
- there is no need to account for any interaction effects between indirect and direct debt raising costs.

On this basis, consistent with its draft decisions, the AER considers it inappropriate to include an allowance for indirect debt raising costs.

Direct debt raising costs

Regulatory precedent—the Allen Consulting Group approach

To determine direct debt raising costs for the draft decisions, the AER adopted the methodology established by the Allen Consulting Group (ACG) in its 2004 report.[773] In developing its methodology, ACG considered evidence from a wide range of sources on international debt raising costs, regulatory practice in Australia, and domestic and international bond markets.

To ensure relevance to the context in consideration, ACG assessed actual debt issued by Australian utility and infrastructure companies, including domestic bonds, term loans and international bonds. ACG broke down the direct debt raising costs into gross underwriting fees, legal and road show fees, company credit rating fees, issue credit rating fees, registry fees and paying fees.[774] A recommendation was made for the costs of each of these categories, based upon available evidence including Bloomberg and Standard and Poor's data. Since a proportion of these costs are fixed, the number of bonds issued in a regulatory control period has a material effect on debt raising costs. The ACG methodology determines the number of standard–size issues that are required to fund the debt portion of the opening RAB of each regulated firm, and apportions fixed and variable costs on this basis. This gives a benchmark percentage, which is applied to the debt portion of the RAB each year to determine the debt raising cost allowance.

Consistent with previous transmission determinations, the AER applied this approach to calculate the allowance for direct debt raising costs in the draft decisions.[775]

Alternative to the ACG approach

The NSPs disputed the draft decision on direct debt raising costs, and proposed allowances of 12.5 bppa in their revised regulatory proposals.[776] The NSPs, through CEG, relied on a working paper by Saunders, Palia and Kim as an alternative estimate of direct

[773] ACG, *Debt and Equity Raising Transaction Costs*, December 2004, pp. 27–53.
[774] ACG, December 2004, p. 52.
[775] AER, *TransGrid draft decision*, p. 139; AER, *Transend draft decision*, pp. 191–192; AER, *NSW DNSP draft decision*, p. 188 and AER, *ACT draft decision*, p. 106.
[776] TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57 and EnergyAustralia, *Revised regulatory proposal*, p. 107.

debt raising costs.[777] In the draft decision, the AER considered that this work was not relevant as it measured debt issued by non–regulated US firms. Further, the AER considered that the high variance in debt issuance costs presented in the paper suggested that use of the market–wide average debt raising cost was not appropriate.[778]

In reiterating the Saunders et al working paper as providing an appropriate estimate, TransGrid and EnergyAustralia responded to the draft decision in the following three ways:[779]

- the AER sample contained the same biases as the Saunders et al sample, including US firms and excluding regulated utilities[780]
- the use of US–based data would produce a lower estimate than Australian–based data, since the market there was more liquid[781]
- 'the private debt market has ceased to exist in the wake of the global financial crisis', and so could not be used as an estimate.[782]

The AER refutes the NSPs' claims and notes:

- the ACG data is exclusively based on Australian firms operating in the utilities and infrastructure sectors.[783] It is incorrect for TransGrid to state that this is not the case, or that 'such data is not publicly available'[784]
- no empirical evidence has been presented by any NSP or consultants to support the claim that liquidity issues cause a debt premium in Australia relative to the USA. Regardless, the AER considers numerous factors in addition to liquidity must be considered
- CEG consider that the private debt market still exists, and note anecdotal evidence of a private–placed NAB debt issue 'at the time of writing'.[785]

The AER considers that the key question is which of the two methodologies best estimates the direct costs incurred by a benchmark firm issuing debt under the regulatory framework in Australia. The AER considers that if the desired target cannot be measured directly, the closest matching alternative should be selected. This is analogous to CEG's statement:[786]

> If one is attempting to estimate the cost of something it is preferable to use data on the cost of that thing rather than data on the cost of something else.

---

777 Kim, Palia and Saunders, January 2003.
778 AER, *TransGrid draft decision*, p. 138.
779 CEG included a fourth argument; that the AER was inconsistent in taking one portion of a study and ignoring other portions of the same study. This issue is not relevant to the choice between Kim, Palia & Saunders and ACG, and is dealt with later in this appendix.
780 TransGrid, *Revised revenue proposal*, p. 77; EnergyAustralia, *Revised regulatory proposal*, p. 106. See also CEG, May 2009, p. 43, paragraph 142.
781 TransGrid, *Revised revenue proposal*, p. 77; EnergyAustralia, *Revised regulatory proposal*, p. 106. See also CEG, May 2009, p. 43, paragraph 141.
782 TransGrid, *Revised revenue proposal*, p. 77.
783 The full list of companies is included at appendix A of the 2004 ACG report, and includes energy sector companies Australian Gas Light, United Energy, ETSA Utilities and SPI Australia.
784 TransGrid, *Revised revenue proposal*, p. 77.
785 CEG, January 2009, pp. 40–41, paragraphs 135–136.
786 CEG, January 2009, p. 36, paragraph 119.

A comparison of the main characteristics of the two approaches is included in table E.1, with areas of difference from a benchmark firm shaded on the table.

Table E.1: Comparison of study characteristics with the benchmark scenario

	Firm Location	Debt Market	Firm Type	Debt Type
Benchmark firm[a]	Australian	Australian[b]	Regulated electricity network	Public
ACG (Bloomberg/ S&P)	Australian	USA[c]	Regulated utility and infrastructure	Private
Saunders, Palia & Kim (2003)	USA	USA	Excludes all regulated firms	Public

Source: Compiled from ACG (2004) and CEG (2008).
(a) For clarity, the AER restates that the benchmark efficient NSP is a pure play regulated electricity network operating in Australia without parent ownership.
(b) While the benchmark debt issue is in the Australian market (consistent with the cost of debt being based on Australian corporate bond yields); in practice, a firm may choose to establish a debt portfolio that includes foreign bonds where it believes this is more efficient, bearing the risk and rewards of this action.
(c) Although the ACG methodology estimates underwriting spread from the US market, it does include Australian estimates for other components of debt raising costs.

The AER observes that neither measure of direct debt raising costs is a perfect match for the benchmark firm. Both the ACG methodology and the Saunders et al approach are based on US market data, not Australian market data. The ACG sample differs from the benchmark in one additional way; it measures private debt rather than public debt. However the Saunders et al sample differs from the benchmark in two additional ways; it is based on US firms (not Australian) and its sample excludes all regulated firms.

Given that the two approaches vary from the benchmark scenario in differing ways, the closest match will be that approach whose differences have the smallest combined impact. The common difference arising from measurement of US debt markets rather than Australian debt markets can be discounted as equally impacting upon both approaches.

The ACG approach uses private debt issuance costs rather than public debt issuance costs. The AER considers that this difference will exert limited (if any) systematic bias on the measurement of direct debt raising costs. It makes this inference on the basis of the Livingston and Zhou study that found no significant difference between public and private debt raising costs.[787] The AER is aware that this study was based on US firms and that it used a range of firms (based on market distribution) rather than exclusively regulated utilities. Nonetheless, the AER considers that Livingston and Zhou does not provide evidence of any difference between public and private debt issuance costs. To exclude this study from application to the benchmark firm, the NSPs would have to argue that the public/private difference exists for regulated firms but not for the market as a whole. No theoretical rationale for such a statement exists, and no empirical evidence has been presented to support such a statement. Accordingly, the AER considers that the

787 Livingston, M. and Zhou, L. (2002) *The Impact of Rule 144A Debt Offerings Upon Bond Yields and Underwriter Fees,* Financial Management, Winter 2002, pp. 5–27.

ACG methodology provides a very close proxy to the benchmark scenario (except for the shared imperfection of measuring US market data).

The Saunders et al approach excludes all regulated firms from analysis, rather than using a sample that consists entirely of regulated utilities.[788] The AER considers that this will have a significant systematic influence on the measurement of direct debt raising costs. The AER observes that although the Saunders et al working paper finds average direct debt raising costs of 68 basis points, the fifth percentile direct costs lie at 23 basis points, while the 95th percentile lie at 353 basis points.[789] The AER considers that given this large range, it is inappropriate to take the sample average and apply it to a set of firms that do not intersect with the original sample. Saunders et al find that firm–specific characteristics account for the majority of variation (51.7 per cent) in direct costs.[790] The AER considers that this further supports the inference that regulated utilities would significantly deviate from the sample average direct debt raising costs. Finally, research papers that compare regulated firms and utilities to other firms find that their status has a significant influence on direct debt raising costs.[791] The AER therefore considers that exclusion of regulated firms is a significant departure from the benchmark scenario.

The Saunders et al approach also differs from the benchmark as it is based on US firms rather than Australian firms. The AER considers that although cross–country differences are numerous, the effect of firm location will be overshadowed by the effect stemming from debt market location. Since both the ACG and Saunders et al approaches issue debt in the US, the additional difference stemming from the firm being located in the US is not expected to be of great significance.

Overall, the AER considers that the appropriate benchmark should be determined according to the ACG approach, which is based upon the cost of Australian regulated utilities issuing private debt in the United States. The AER considers this to be closer to the benchmark scenario than the Saunders et al approach, which is based on American non–regulated firms issuing public debt in the United States.

Consideration of components from one report

CEG stated the AER was inconsistent to take one proposition from the Livingston and Zhou study—that public debt has the same issuance costs as private debt—and reject another proposition from the same study, that gross underwriter spread is between 8.8 bppa and 9.6 bppa.[792]

The AER considers that the joint acceptance of two propositions from one research paper depends upon the degree to which the two propositions are linked in that paper. Research papers may include chains of logic that develop serially across the paper, but frequently include several investigative approaches, each of which stands in isolation. There may be no relationship between the two propositions, in which case the AER considers it is appropriate for a party to accept one and reject the other on merit. Inconsistency would

788 Kim, Palia and Saunders, 2003, p. 7. The AER notes that a sample consisting purely of regulated electricity networks would be the best match for the benchmark firm.

789 Kim, Palia and Saunders, 2003, p. 35, table 1.

790 Kim, Palia and Saunders, 2003, p. 40, table 6.

791 See Eckbo and Masulis, *Adverse selection and the rights offer paradox*, Journal of Financial Economics, 1992, vol. 32, pp. 293–332; and Livingston and Zhou, 2002, p. 25, table VIII.

792 CEG, January 2009, p. 39, paragraph 129. Note that gross underwriting spread is not the total direct costs; this point is further elaborated later in this discussion.

only occur where it is shown that the relevant propositions in the paper are dependent on each other. Even if the two propositions are part of one chain of reasoning, then it is still logically defensible to accept the earlier proposition, but reject the latter on the grounds that an error of fact, logic or relevance occurred after the first proposition (and before the second). However, it would be inconsistent to accept a later proposition that was wholly dependent upon an earlier proposition, where the earlier proposition had been rejected as incorrect.

In considering CEG's claim, the two propositions may be summarised as follows:

1. the Livingston and Zhou regression supports that the issuance costs of public debt and private debt do not differ
2. the issuance costs projected from the full Livingston and Zhou regression will be equal to issuance costs of the benchmark firm.

However, proposition one is not dependent on proposition two. Therefore the AER considers that it is entitled to use its own estimate of direct debt raising costs. The AER considers that these propositions are part of the same logic chain, flowing from the same regression analysis. However, as the first proposition is made earlier in the Livingston and Zhou argument, an acceptance of this proposition by the AER does not infer that the second proposition must also be accepted. The AER considers that there is no inconsistency in rejecting the second proposition if the AER is convinced that the logic of argument breaks down after the first proposition. The two propositions are considered below.

Interpretation of the Livingston and Zhou regression

CEG stated that the Livingston and Zhou study found a gross underwriter spread of between 8.8 bppa and 9.6 bppa.[793] The underwriter spread is not the total direct debt raising cost as it does not include other relevant fixed costs or rating costs. This range is derived from a regression that investigated the relationship between gross underwriter spread (as the dependent variable) and a range of independent variables.[794]

The AER notes that the widely accepted scientific framework emphasises the need for caution when applying a regression projection to new data points that differ substantially from the data used in its derivation. For example, there will generally be a significant difference between the debt risk premium of the Livingston and Zhou sample of public firms,[795] and the debt risk premium on the public bond issued by the benchmark firm.[796] The AER notes that the full regression was conducted to observe the impact of Rule 144A placements relative to other placement methods, and that this purpose does not match the purpose for which CEG applied the regression results. In particular, the AER observes that Livingston and Zhou chose not to include the presence or absence of industry regulation as an independent variable, and that such a variable would be particularly pertinent to CEG's interpretation and projection.

793 CEG, January 2009, p. 38, paragraph 127.
794 Livingston and Zhou, 2002, p. 25, table VIII.
795 Livingston and Zhou, 2002, p. 12, table I. The rule 144A bonds had average debt risk premium of 351 basis points, which mitigates but does not eliminate this risk.
796 The AER notes that although debt risk premiums change over time, the benchmark firm debt risk premium is currently more than three times the Livingston and Zhou public bond average.

The AER notes that CEG derived an upper bound for direct debt raising costs, and that CEG stated this calculation followed the generally accepted best practice of using all independent variables for a projection, regardless of statistical significance. However, the AER observes that CEG omitted two variables, *Log of Proceeds*[797] and *Percentage of Years of Call Protection*,[798] and miscalculated another, *Log of Issue Frequency*.[799] The inclusion and correction of these variables in the regression projection[800] would result in the range of underwriting spreads presented in table E.2.[801]

Table E.2: Corrected regression projections of gross underwriter spread for each NSPs

Issuer	TransGrid	Transend	Country Energy	Energy Australia	Integral Energy	ActewAGL
Total cost (bp)	56.1	60.9	56.1	54.0	56.7	62.2
Annual cost (bppa)[a]	7.46	8.10	7.46	7.18	7.54	8.27

Source: AER analysis, based on Livingston and Zhou (2002).
(a) Annual figures have been derived using the CEG amortisation methodology.

The gross underwriter spreads range from 54.0 to 62.2 bppa, which is between 4.8 and 13 basis points lower than the CEG–quoted best estimate of 67 bppa. If amortised over 10 years (as per the CEG methodology, using a real weighted average cost of capital (WACC) of 6.99 per cent) this equals an allowance of between 7.18 and 8.27 bppa.

The AER notes that gross underwriter spread is not the only type of direct cost. Direct costs also include legal fees, rating fees and other costs. In the latest update of the AER methodology, a gross underwriter spread of 6.0 bppa was applied to all NSPs with other costs adding between 3.2 and 2.0 bppa. While the correction of CEG errors reduces the difference, the Livingston and Zhou regression projection remains at least 1.18 bppa higher than the underwriting allowance of 6.0 bppa which was included in the draft decision.

The AER notes that marked differences in approach have resulted in a material difference between the two estimates of underwriting costs. The Livingston and Zhou regression analysis is based upon amortised 10–year debt, rather than straight division of five–year debt as per the ACG methodology.[802] The ACG methodology was based on Australian

797 Log of proceeds is expressed in $US dollars, so the $AU 200 million benchmark bond size was converted to ln(150).
798 Call protection refers to the inability of the issuer of the bond to 'call back' (i.e. force redemption) earlier than the maturity of the bond. Since the regulated benchmark firm can predict its cash flow and gearing, it can safely issue 100 per cent call protected bonds to reduce borrowing costs.
799 The January 2009 CEG report considered only the case of Integral Energy, which would make 11 issues in 10 years (and therefore 3.3 issues in the 3 years of the study). Figures relevant for other NSPs can be derived using reasonable assumptions (60 per cent of RAB is debt, issue size of $AU 200 m, $AU/$US exchange rates of $0.72).
800 The AER notes that seven other significant variables, including six rating variables and the *First Time Debt Dummy*, would have no impact on the projection and were also omitted from the CEG table.
801 The regression is dependent on the number of debt issues made by the firm; since this varies across NSPs, a range of gross underwriter spreads results.
802 Separate consideration of the amortisation/straight division issue is provided later in this appendix.

utility and infrastructure companies issuing debt that closely matches the benchmark firm. In contrast, the Livingston and Zhou estimate is impaired by the difficulties in projecting from regression analysis, as detailed above, and is based on US firms issuing debt in the US market.

Accordingly, the AER concludes that the underwriting estimate of 6.0 bppa, based on ACG's methodology, is most appropriate for determining the level of direct debt raising costs that would be incurred by the benchmark efficient entity. Other direct debt raising costs must be added to this gross underwriting spread such as legal and roadshow, company credit rating, issue credit rating, registry and paying fees. The AER notes that no estimate of these figures is made by CEG (or Saunders et al), and that therefore the ACG methodology remains the only viable approach for estimating these costs.

AER conclusion—direct debt raising costs

The AER notes the view of Associate Professor Handley, who concluded that an appropriate range for total direct debt raising costs was between 8 and 12 bppa.[803] The AER views the upper end of this range, derived from Saunders et al (~12 basis points) and the Livingston and Zhou full regression (~10 basis points) as being unreliable, for the reasons detailed earlier in this appendix.

In conclusion, the AER considers that:

- the exclusion of regulated firms from the Saunders, Palia and Kim working paper makes it an inferior estimate of direct debt raising costs when compared to the ACG methodology
- the problems associated with applying a regression projection and the incorrect firm location makes the full Livingston and Zhou regression projection an inferior estimate of direct debt raising costs when compared to the ACG methodology
- an individual component of the Livingston and Zhou paper (namely the equivalence of public and private debt raising costs) can be accepted separately to the full Livingston and Zhou regression projection.

On this basis, consistent with its draft decisions, the AER concludes that the ACG methodology is the most reliable and accurate method for setting direct debt raising costs, and that it will be applied for all NSPs.

Other issues

Current market conditions

CEG argued that the cost of issuing debt is likely to be at historically high levels and that an estimate from the top end of any historical range is appropriate.[804] CEG base this claim on the rapid change in the global economy in the past year.

The AER notes that this issue was not addressed in the draft decisions, as the likely impact of the global financial crisis was not yet evident. The AER notes the change in the

803 Handley, April 2009, p. 30.

804 CEG, January 2009, p. 42, paragraph 140. Note that the effects of current market conditions on the cost of debt (in contrast to the cost of issuing debt) are considered in detail in section 4.5.2 of this final decision.

economic outlook for the Australian economy since mid–2008 has been reflected in official forecasts by Treasury.[805] The rapid change in the economic outlook is closely linked to the global financial crisis which manifested itself in the second half of 2008. The global financial crisis has been portrayed as being the most serious economic event affecting developed economies since the great depression of the 1930s.[806]

Given this extraordinary change in circumstances within the economic environment, the AER has decided to consider the updated information relating to debt raising costs in making its final decision.

Pursuant to the ACG methodology, the AER sets debt raising costs on the basis of a long–term benchmarking approach. The benchmark debt raising costs applied in the draft decision reflect a 2008 update of the ACG 2004 findings on debt raising costs. The standard debt issuance costs are set based on a benchmarked sample of debt issues over the time period 2000–2008.

While there will always be volatility in debt markets and variation in the cost of raising debt, the AER approach, consistent with the NER framework, takes a long–term view of debt raising costs. The AER's update, based on benchmarked data over 2000 to 2008, found that the appropriate gross underwriting fee for issuing debt remains at 6.0 bppa. The 2008 update included three additional bond issues by BHP on 26 March 2007 as set out in table E.3. The average underwriting fees on these bonds were consistent with the 2006 update benchmark.

Table E.3: BHP Billiton international bond issues, 26 March 2007

Issuer	Years to maturity	Issue size ($millions)	Total gross underwriting fees
BHP Billiton	2	$1080.4	0.10% or 5.0 bppa
BHP Billiton	5	$771.7	0.35% or 7.0 bppa
BHP Billiton	10	$926.0	0.45% or 4.5 bppa

Source: AER analysis, based on data from Bloomberg.

The only evidence put forward by CEG that an estimate from the top end of the historical range is appropriate was the bond issue from National Australia Bank (NAB) in the US private placement market. CEG argued that NAB's issue costs of 7.6 bppa indicates the AER's estimate of 6 bppa is too low.

The AER notes that the NAB issue was for a tenor of 3 years while the benchmark estimate by the AER used a tenor of 5 years.[807] Further, the underwriting cost observed for one bank debt issue is not, in isolation, an appropriate benchmark for setting debt raising costs.

805 The Treasury, *Updated Economic and Fiscal Outlook*, February 2009. Available: http://www.budget.gov.au/2008-09/content/uefo/html/index.htm.

806 IMF, *World Economic Outlook*, October 2008.

807 The AER notes that, as a number of costs are likely to be one–off fixed costs, going from three to five years maturity will reduce the basis points per year cost.

The AER does not consider the evidence in relation to one bond issue is sufficient to justify choosing a figure from the top end of historical range and depart from the AER's methodology of a long–term benchmarking approach to setting debt raising costs.

Amortisation of debt raising costs

In its report, CEG argued that the current debt issuance methodology used by the AER is biased as it fails to take into consideration the time value of money.[808]

The AER's methodology involves dividing total issuance costs by the debt maturity to obtain an annual allowance, rather than equating the net present value of the yearly payments with the total debt issuance cost using an appropriate discount rate.

The AER notes that this issue was not raised by the NSPs in their regulatory proposals, but was raised for the first time in their revised regulatory proposals. This issue was not raised in response to a matter addressed in the draft decision. As such the AER considers it need not review the variation to the methodology as requested by the NSPs.[809] Notwithstanding this aspect, the AER has undertaken a review of the NSPs' proposed variation to the methodology.

The AER acknowledges that an adjustment for time value of money is generally appropriate when upfront costs are repaid over time. In this instance, following the ACG methodology, no such adjustment is made. However, the key outcome is that the AER's conservative approach does not under compensate the NSPs.[810] The modelling employed by the AER to estimate debt issuance costs assumes that five year maturity bonds are issued. The ACG methodology simply divides the total debt issuance cost of a five year bond by five, to derive an annual allowance.

However, the NER requires that the benchmark bond is of a ten year term.[811] Therefore, if amortisation were to be undertaken in accordance with the term of the bond specified in the NER, it would be based on a ten year horizon, involving the change of bond term from five years to ten years. Given that a proportion of debt issuance costs are made up of fixed costs, the debt issuance costs for a ten year bond will not be significantly larger than the debt issuance costs of a five year bond. The amortised cost of ten year debt issuance costs would provide a lower allowance than the simple division of five year debt issuance costs.[812] The AER considers that the current ACG methodology is therefore a conservative approach, in that the NSPs are no worse off (and in fact are likely to be slightly better off) than under an amortisation approach.

On this matter, Associate Professor Handley considered that the differences between amortisation and simple division are not sufficient to warrant consideration.[813]

The AER has assessed the evidence presented by the NSPs on amortisation costs. On the basis of this assessment, the AER considers there is no requirement to amend the methodology applied in the draft decision, for the following reasons:

808 CEG, January 2009, pp. 47–48, paragraphs 157–166.
809 For TNSPs, see clauses 6A.14.3(h) and 6A.14.3(c)(3)(ii) of the NER. For DNSPs, see clause 6.10.3(b) of the transitional chapter 6 rules.
810 ACG, 2004, pp. xvi–xix.
811 NER, clause 6A.6.2.
812 AER analysis.
813 Handley, April 2009, pp. 29–30.

- a new methodology cannot be presented in a revised regulatory proposal unless it is addressing a matter raised in the draft decision
- amortisation would have to occur over ten years, not five, so the allowance would be unlikely to increase (and may even decrease).

Overall, the AER is satisfied that its methodology ensures that the NSPs will have the opportunity to recover at least the efficient costs, as is required by the NER.[814]

Inflation of debt issuance costs

CEG argued that the non–underwriting transaction costs in debt issues should be indexed for inflation.[815] The AER notes that this issue was not raised in the NSPs' regulatory proposals, but raised for the first time in their revised regulatory proposals. This issue was not raised in response to a matter addressed in the draft decision. As such the AER considers it need not review the variation to the methodology as requested by the NSPs. Notwithstanding this aspect, the AER has undertaken a review of the NSPs' proposed variation to the methodology.[816]

The AER considers that the argument for inflation indexing raised by CEG is not theoretically sound. Given that issuance costs are expressed as a percentage (total debt issuance costs divided by debt size), it is inconsistent to focus on the changes in the numerator without considering the effects on the denominator. The AER considers that while the fixed costs may increase by inflation, the size of the debt issue will also increase by inflation.

The AER considers that this problem is illustrated by consideration of an extreme case. If inflation was to be applied only to fixed costs and not to the amount of debt issued, then at some future point the percentage cost of issuing debt would surpass 100 per cent. The AER considers that this is not a plausible outcome, as the amount of debt issued would not be enough to cover the costs associated with the debt issue. In this case, the debt market would not exist.

The AER notes the view of Associate Professor Handley, who advocated that the effect of any proposed inflation indexation is below a reasonable threshold of materiality.[817]

The AER has considered the argument presented by the NSPs for an allowance for indexation. On the basis of this assessment, the AER considers there is no requirement to index debt issuance costs, for the following reasons:

- a new methodology cannot be presented in a revised regulatory proposal unless it is addressing a matter raised in the draft decision
- the indexation of debt issuance costs without also adjusting for changes to bond issue size is likely to result in implausible outcomes in the long–term.

---

[814] For TNSPs, see clauses 6A.14.3(h) and 6A.14.3(c)(3)(ii) of the NER. For DNSPs, see clause 6.10.3(b) of the transitional chapter 6 rules.

[815] CEG, January 2009, p. 49, paragraphs 167–169.

[816] For TNSPs, see clauses 6A.14.3(h) and 6A.14.3(c)(3)(ii) of the NER. For DNSPs, see clause 6.10.3(b) of the transitional chapter 6 rules.

[817] Handley, April 2009, pp. 29–30

Summary of debt raising cost considerations

The AER has considered the arguments made by the NSPs on debt raising costs, including consultant reports and all relevant submissions.

The AER considers that there is no basis for an allowance for the indirect costs of debt raising. The AER has found no reliable empirical evidence of the existence of underpricing. If indirect costs do in fact occur in practice, the current methodology of providing an allowance for the cost of debt would detect and include compensation as part of the debt yield. Therefore, separate compensation would result in double counting and be inconsistent with the regulatory framework.

The AER considers that the ACG methodology represents the best estimate of the direct costs of debt raising. This is determined by the close proximity of the ACG approach to the benchmark scenario; issuance of BBB+ rated public debt by the benchmark firm in Australian debt markets. The AER considers that none of the proposed alternative methodologies are appropriate, principally because of their failure to consider the characteristics of debt issued by regulated utilities.

The AER considers that there is no reason to deviate from the established approach as a result of transient market conditions. Finally, the AER finds no evidence of material under–compensation for the benchmark firm sufficient to warrant methodological change to accommodate amortisation and inflation.

For the NSPs, the AER has maintained the application of the established ACG methodology to determine the appropriate benchmark allowance for direct debt raising costs in this final decision. This allowance will be dependent upon the number of standard sized debt issues required by each NSP. The allowance, expressed in bppa, will then be applied to the debt portion of each NSP's RAB for each year of the next regulatory control period to determine the benchmark debt raising costs included in the opex forecast.

Equity raising costs

Rationale for joint consideration

Similar to the approach for debt raising costs, the NSPs have adopted a joint position in relation to proposed equity raising costs. In their revised regulatory proposals, the NSPs have essentially[818] applied the same parameters for equity raising costs:

- a base unit rate for equity raising costs of 7.6 per cent of the external equity required each year[819]
- an allowance for use of retained earnings of 3.8 per cent of retained earnings between normal dividend yield and minimum dividend yield[820]

---

818 TransGrid stated that retained earnings were not costless and included an allowance in its equity raising calculations, but unlike the other NSPs it did not include the retained earnings allowance in its revised total opex allowance.

819 TransGrid, *Revised revenue proposal*, p. 82; Transend, *Revised revenue proposal*, p. 60; Country Energy, *Revised regulatory proposal*, p. 46; EnergyAustralia, *Revised regulatory proposal*, p. 49; Integral Energy, *Revised regulatory proposal*, p. 47 and ActewAGL, *Revised regulatory proposal*, p. 33

- revision of the AER's cash flow analysis to incorporate the repayment of debt principal and distribution of all imputation credits.[821]

It should be noted that although the theoretical arguments on setting the dividend level were identical across the NSPs, the practical implementation differed:

- Transend implemented a 5.5 per cent dividend yield[822]
- TransGrid and EnergyAustralia implemented a 70 per cent dividend payout ratio[823]
- Integral Energy implemented the 70 per cent dividend payout ratio, but proposed an additional system for tracking imputation credits and compensating the firm.[824]

As with debt raising costs, the shared position of the NSPs is reinforced by reliance on the same consultant reports. In the NSPs' regulatory proposals variants of the CEG report were submitted.[825] In their revised regulatory proposals, a report by CEG is referenced and submitted by the NSPs—all submitted versions are the same apart from the titles.[826] TransGrid and EnergyAustralia also submitted a report by Tony Carlton, although there are some variations between the two versions.[827] EnergyAustralia submitted a report by Professor Bruce Grundy.[828] Further, EnergyAustralia's submission requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and revised regulatory proposal be considered by the AER in making its final determination for all the NSPs.[829]

Integral Energy submitted a report by KPMG[830] and comments on cash flow modelling.[831] TransGrid submitted an additional memorandum by CEG,[832] as well as a

820 TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, pp. 48–49; Integral Energy, *Revised regulatory proposal*, p. 45–46. Transend, Country Energy and ActewAGL did not explicitly adopt this position, but referenced support for the January 2009 CEG report.

821 TransGrid, *Revised revenue proposal*, pp. 80–81; Transend, *Revised revenue proposal*, p. 60; EnergyAustralia, *Revised regulatory proposal*, pp. 47–48; Integral Energy, *Revised regulatory proposal*, pp. 46–47. Country Energy and ActewAGL did not explicitly adopt this position, but referenced support for the January 2009 CEG report.

822 Transend, *Revised revenue proposal*, p. 60.

823 TransGrid, *Revised revenue proposal*, p. 81; and EnergyAustralia, *Revised regulatory proposal*, pp. 48–49

824 Integral Energy, *Submission to the Australian Energy Regulator 2009 to 2014*, 16 February 2009, p. 10; see also Attachment 3.

825 CEG, May 2008 (TransGrid); CEG, May 2008 (Transend); CEG, May 2008 (Country Energy), CEG, May 2008 (EnergyAustralia); CEG, April 2008 (Integral Energy).

826 CEG, January 2009. Cited by TransGrid, *Revised revenue proposal*, p. 77; Transend, *Revised revenue proposal*, p. 56; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 105; Integral Energy, *Revised regulatory proposal*, p. 43; and ActewAGL, *Revised regulatory proposal*, p. 33.

827 Carlton, January 2009 (EnergyAustralia); Carlton, January 2009 (TransGrid).

828 Grundy, B. D., *A Note on the Costs of Equity Financing*, 13 January 2009.

829 EnergyAustralia, *Submission*, 16 February 2009.

830 KPMG, *Review of Certain Assumptions in the AER's Financial Model to support the draft NSW Distribution Network Revenue 2009–2014*, report to Integral Energy, January 2009.

831 Integral Energy, *Submission*, 16 February 2009.

832 CEG, *Memorandum on the Ofgem treatment of Equity raising costs*, 18 February 2009.

report by SFG.[833] The JIA submitted a report by CEG that merges parts of the May 2008 and January 2009 CEG reports with new analysis.[834]

The AER notes that issues relating to the equity raising costs on the initial opening regulatory asset base are specific to Transend and do not relate to the argument for benchmark equity raising costs associated with forecast capex. Accordingly, any submissions or arguments solely related to this issue are not dealt with in this appendix. All references to ‘equity raising costs’ in this appendix refer to equity raising costs associated with forecast capex.

Due to the consistency between the opex provisions of the NER under which the equity raising cost proposals are assessed, the NSPs’ revised regulatory proposals and the supporting consultancy reports, the AER jointly assessed equity raising costs of the NSPs. The AER’s analysis and conclusions are contained in this appendix, which is reproduced in each of the AER’s final decisions for the NSPs.

The AER considers that it is important for a consistent methodology to determine the appropriate allowance for benchmark equity raising costs to be applied in its final decisions for the NSPs.

Regulatory framework for equity raising cost allowance

The CAPM encapsulates the return required by the providers of equity capital given the inherent risk in each asset. The WACC determines a total rate of return given mandated assumptions about the gearing of the benchmark firm and the cost of debt capital. This regulatory framework requires the AER to calculate the total return required by investors in aggregate, and includes consideration of company tax, (including the effect of imputation credits). The regulatory framework does not encapsulate personal transaction costs, including the final income tax paid by personal investors, or the rate of return given to any individual capital provider (as opposed to investors in aggregate). Associate Professor Handley noted that to be consistent with this framework, all cash flows need to be expressed on a similar basis:[835]

> In other words, cash flows should be after company tax, before personal tax, after underpricing costs but before other personal (transaction) costs.

The regulatory allowance for equity raising costs should compensate the benchmark firm for the transaction costs incurred as a result of required equity capital raising (referred to as equity raising costs). Such transaction costs may be appropriately considered as part of an NSP’s opex forecasts (while rate of return issues cannot be considered under the opex provisions of the NER). As an opex item, the proposed equity raising cost allowance is subject to the NER requirement that forecast opex reasonably reflects the costs that a prudent operator in the circumstances of the relevant NSP would require to achieve the opex objectives.[836] This is in contrast to an allowance for the return on capital, which is separately described in clause 6A.6.2 of the NER for TNSPs and clause 6.5.2 of the

833 SFG, March 2009.
834 CEG, November 2008.
835 Handley, April 2009, p. 10.
836 For DNSPs, see clause 6.5.6(c)(2) of the transitional chapter 6 rules. For TNSPs, see clause 6A.6.6(c)(2) of the NER.

transitional chapter 6 rules for the ACT/NSW DNSPs for the next regulatory control period .[837]

The AER considers that it is essential to correctly characterise the components of the equity raising allowance, to ensure elements more correctly attributable to the rate of return are not included as transaction costs.

Deviations from the benchmark firm

The AER notes that many of the NSPs are government owned. The AER considers that this deviation from the benchmark structure is likely to result in windfall gains to the government owned NSPs, as they do not issue shares and therefore do not incur equity raising costs to the extent that the benchmark efficient NSP does.[838] Additionally, the obtained value of imputation credits (gamma) for these government owned NSPs will effectively be zero (rather than 0.5), since the government receives both taxes—paid under the National Tax Equivalence Regime (NTER)—and dividends as the shareholder. In this instance, imputation credits are of no additional value to the shareholder as any gains are offset by a reduction in taxes received. Despite these deviations from the benchmark firm, the AER considers that it is appropriate to assess the NSPs in accordance with the notional benchmark firm, that is, as a pure play regulated electricity network operating in Australia without parent ownership. This is consistent with competitive neutrality principles for the treatment of government owned firms.

Indirect costs of equity raising

The NSPs' revised regulatory proposals disputed the draft decision on indirect equity raising costs, also known as underpricing. The NSPs proposed a total equity raising allowance of 7.6 per cent, including both direct and indirect components.[839] TransGrid stated that indirect and direct costs cannot be considered in isolation, but must be jointly determined and measured. The NSPs' revised regulatory proposals generally provided a summary statement in justification of an allowance for indirect costs, referring to consultant reports for evidence.[840]

837 The AER notes that it is undertaking a review of WACC concurrent with its review of TransGrid's and Transend's revenue proposals. The WACC review involves the consideration of parameter inputs into the CAPM and WACC. The AER further notes that for the purposes of the AER's ACT/NSW distribution determinations for the next regulatory control period, the rate of return parameters were set within transitional provisions of the NER.

838 The AER notes that the NSW State Owned Corporations (TransGrid, Country Energy, EnergyAustralia and Integral Energy) have only issued two shares each, one of each pair held by the NSW Treasurer and the other by the NSW Minister for Finance; see State Owned Corporations Act 1989, Part 3, Division 2, Section 20H. Transend has four shares, all held by the Crown in Right of the State of Tasmania; see Transend, *Annual report 2007–08*, p. 41. ActewAGL is a 50/50 partnership between Actew Corporation (a wholly owned ACT Government corporation with two shares— held by the ACT Chief Minister and Deputy Chief Minister) and Jemena Networks (ACT), a privately owned company; see ActewAGL, *Annual and Sustainability Report*, 2008, p. 4.

839 TransGrid, *Revised revenue proposal*, p. 82; Transend, *Revised revenue proposal*, p. 60; Country Energy, *Revised regulatory proposal*, p. 46; EnergyAustralia, *Revised regulatory proposal*, p. 49; Integral Energy, *Revised regulatory proposal*, p. 47; and ActewAGL, *Revised regulatory proposal*, p. 33.

840 For example, TransGrid, *Revised revenue proposal*, pp. 80–81; EnergyAustralia, *Revised regulatory proposal*, p. 43.

Personal transaction costs

CEG stated that, when equity raising via rights issue occurs, existing shareholders that allow their rights to lapse have their investments diluted. CEG inferred that shareholders may prefer to avoid this dilution by either selling their rights (if renounceable) or taking up the rights before immediately selling the new share (if non–renounceable). CEG noted that either action incurs transaction costs, with the latter action possibly resulting in realisation of capital gains. CEG argued that these transaction costs reflect the indirect cost of a rights issue.[841]

The AER considers that separate compensation for investor level transaction costs, including investor level taxes is inconsistent with the regulatory framework. The regulatory framework specifies that investor returns are post company tax and pre–investor tax.[842] This is consistent with conventional financial theory.

Officer and Hathaway state:[843]

> …the CAPM is typically used in the context of post–company tax but pre–personal tax returns because that is the tax band in which the vast majority of capital market transactions take place.

Finance textbook, Business Finance, states:[844]

> Conventionally, the cost of equity, k_e, is defined and measured on an after–company tax, but before personal tax, basis.

Similarly, transaction costs involved with buying and selling shares are outside the regulatory framework. The market risk premium is estimated on a market portfolio that is exclusive of the transaction costs involved in maintaining that portfolio. This was the point made by Associate Professor Handley when he stated:[845]

> The regulatory framework requires the determination of allowed revenues to the regulated firm to be undertaken on an after company but before personal tax basis. In the current context, this is more fully described as a requirement to be undertaken on an after company tax, before personal tax, after underpricing costs but before other personal (transaction) costs basis.

The AER considers that the regulatory framework does not allow for consideration of investor personal tax rates, either as income tax or capital gains tax. Under the regulatory framework, investors are assumed to be indifferent between dividends and capital gains.[846] Accordingly, the possible realisation of a capital gain does not require any allowance or offsetting adjustment.

841 CEG, January 2009, pp. 14–15, paragraph 37–43.

842 The AER notes that this is why imputation credits are deducted from the regulatory building blocks when determining total allowed revenue for the business; to the extent that they will be redeemed, they are not company taxes but pre–payment of personal taxes.

843 Officer, R. and Hathaway, N. J., *Issues in Cost of Capital for QCA, Report by Capital Research Pty Ltd for Prime Infrastructure submission to the QCA*, March 2004, p. 2.

844 Peirson, G., Brown, R., Easton, S. and Howard, P., *Business Finance: 8th Edition*, McGraw–Hill, 2003, p. 449.

845 Handley, April 2009, p. 10.

846 The Sharpe CAPM assumes indifference between dividends and capital gains because there are no personal income taxes. Additionally, the estimated market risk premium is based on a cumulative return of both dividends and capital gains. This is not to say that dividends are entirely irrelevant (see

The AER has considered the impact of transaction costs (i.e. brokerage, search costs, bank fees) under the regulatory framework. The AER notes that a transaction occurs when the renounceable right[847] is sold, and that two transactions occur when the non–renounceable right[848] is taken up and a new share sold. However, the AER considers it inappropriate to determine that such transactions are 'extra' or 'forced' transactions—that would accordingly require compensation—without considering the pattern of transaction costs that an investor in the market ordinarily incurs.

CEG considered the case of a benchmark investor with a desired portfolio of investments. If taking up a rights issue shifts this benchmark investor away from its desired portfolio, the investor immediately takes action to restore its optimal mix of assets. The AER notes that, in the extreme case, this investor would need to continually rebalance its investment portfolio in response to any non–systematic price movement of any of its shares. The AER considers that in this case, the constant adjustment of the investor's portfolio would make the cost of one or two additional transactions immaterial. In general, the AER considers it is reasonable to assume that the investor would tolerate some changes within its ideal portfolio, and only rebalance when the changes breach certain boundaries. It may be that in some cases, a rights issue (renounceable or non–renounceable) may not have a sufficiently large effect to cause rebalancing, and all transaction costs would be avoided.

A complete answer can only be determined by a long–term comparison of the transactions required when investing in the benchmark firm with the transactions required from an alternative portfolio of investments. Crucially, there are many other aspects of a benchmark firm that reduce the total number of transactions this investor incurs. The benchmark firm pays dividends regularly, unlike capital–growth–only shares, where the investor must sell (and incur transaction costs) each time they wish to access the return on their capital. The benchmark firm has regulated, transparent cash flows, leading to a stable share value, unlike speculative shares which may require portfolio balancing on the basis of price volatility more often.

The AER considers that to demonstrate the need for an allowance on this issue, empirical evidence is required that shows the transaction costs incurred by providing equity to the benchmark firm exceed those incurred by the market on average. Such evidence would demonstrate that regulated firms incur higher equity raising costs than the market on average, for which the market risk premium is estimated. No such evidence has been provided.

The AER considers that an allowance for individual transaction costs is inconsistent with the compensation of opex under the NER. Efficiently incurred expenses are defined as those incurred by the regulated firm—and it would be economically incorrect to make an allowance for all of these costs as all investors incur investor level taxes and transaction costs.

The equity raising cost allowance for the NSPs is designed to allow them to recover company transaction costs. The AER considers the NSPs' argument that investor level

the discussion on valuation of imputation credits later in the appendix) but that the realisation of capital gain cannot be presumed to be a cost to the investor.

847 A renounceable right is one where the existing shareholder can sell their right to purchase additional shares to another investor.

848 A non–renounceable right is one where the existing shareholder must either purchase the additional shares themselves or let the right lapse. The right cannot be sold to another investor.

transaction costs or taxes are incurred by investors due to the use of rights issues or dividend reinvestment programs is not relevant in this context.[849] The NER implies a pre–investor level (post–company tax) CAPM and post–company tax (pre–investor tax) revenue model.[850] This was the point made by Associate Professor Handley when he stated:[851]

> Accordingly, in the current context, observed returns based on dividends, capital gains and (the value of) imputation credits are more fully described as being expressed on an after company tax, before personal tax, after underpricing costs, but before other personal (transaction) costs basis.

Accordingly, the NSPs' argument concerning costs at the investor level is inconsistent with the regulatory framework.

Overall, the AER considers that ad hoc adjustments to the post–company tax and transaction cost CAPM for investor level costs are inappropriate for the following reasons:

- such changes are inconsistent with the NER and with the CAPM as defined in the NER
- the modification of the CAPM for investor level transaction costs has not been shown to be theoretically valid
- such modification could reasonably be expected to lead to systematic over–compensation and monopoly pricing.

The AER notes that it is possible to compare investor–level transaction costs and taxes incurred by investors in Australian NSPs with the average costs incurred by other investors in the Australian market in determining an allowance for equity raising costs. However, the AER notes that implementation of any associated adjustments to allowances would not be consistent with the current rate of return methodology prescribed under the NER, which is based on corporate transaction costs not individual transaction costs.

Wealth transfer effects

CEG and Carlton stated that one aspect of indirect costs is the transfer of wealth from original shareholders to new shareholders.[852] CEG further elaborated on the mechanics of wealth transfer, and provided a detailed appendix on the cost of a rights issue.[853] Carlton provided similar analysis that demonstrated wealth transfer effects with a placement, and stated that for any seasoned equity offer (SEO) if the shares are sold at a discount, then the value of the shares of the original shareholders is diluted.[854]

---

849 For example, see TransGrid, *Revised revenue proposal*, p. 80; EnergyAustralia, *Revised regulatory proposal*, pp. 44–45.
850 NER, Clause 6.5.3.
851 Handley, April 2009, p. 10.
852 CEG, January 2009, pp. 14–15, paragraphs 37–43 and Carlton, January 2009 (EnergyAustralia), p. 9.
853 CEG, January 2009, pp. 50–52, appendix A: Costs of a rights issue.
854 Carlton, January 2009 (EnergyAustralia), p. 39.

Associate Professor Handley observed that:[855]

> Importantly, the set of investors who take up the new shares may include one or more existing shareholders of the firm, one or more new shareholders to the firm, or a combination of both existing and new shareholders.

The AER observes that in a fully subscribed rights issue (as is likely with the heavily discounted rights issue described in the draft decision), there would be minimal wealth transfer, as existing shareholders would be expected to take up the issue and hence there would not be any new shareholders. Associate Professor Handley observed that CEG and Carlton assume that no existing shareholders participate in their benchmark firm placements and stated this was an unrealistic assumption.[856] The AER concurs with Associate Professor Handley's view. The AER considers that it is more plausible to infer that placements are regularly taken up by a mix of old and new shareholders.

The AER considers that under such a scenario, two sources of overcompensation would likely result. Original shareholders who bought new shares would be overcompensated, since the dilution effect would already be offset by the new shares they purchased, and they would also receive the benefit of the proposed underpricing allowance. Additionally, outside investors who took up new shares would also be overcompensated, since they experience no dilution effect (they had no shares to begin with) but still share in the underpricing allowance (paid to the firm as a whole). Associate Professor summarised this scenario as follows:[857]

> Importantly, this reflects the fact that underpricing costs are not borne by the firm but rather represents a transfer of wealth from one group of investors to another.

On this basis, the AER does not consider that an indirect cost allowance is an appropriate mechanism to address purported wealth transfer effects. Further, the AER considers that the regulatory framework requires consideration of returns at the company level rather than the individual level. To address wealth transfer effects would require the AER to assess returns to individual shareholders which is inconsistent with the regulatory framework.

Rights issues

The indirect costs of a rights issue

TransGrid stated 'there is no basis for assuming that a rights issue will eliminate the indirect costs of raising equity'.[858] Similar statements were made by EnergyAustralia.[859] The NSPs also cited evidence from CEG, Carlton and Professor Grundy.

CEG's key argument was that a rights issue shifts costs from the benchmark firm to the individual shareholders, forcing investors to take on an underwriting role. CEG stated:[860]

> …it would be wrong as a matter of logic and economic theory to argue that by forcing existing shareholders to take on the functions of an underwriter the associated costs can be ignored.

855 Handley, April 2009, p. 6.
856 Handley, April 2009, p. 8.
857 Handley, April 2009, p. 8.
858 TransGrid, *Revised revenue proposal*, p. 80.
859 EnergyAustralia, *Revised regulatory proposal*, p. 45.
860 CEG, January 2009, p. 16, paragraph 45–46.

Professor Grundy supported CEG's argument and stated that evidence of the existence of indirect costs with rights issued could be seen in the 'rights offer paradox'.[861] He cited a paper by Hansen, [862] which found that the transaction (indirect) costs of rights issues raise the total cost of rights issues above that of placements. Professor Grundy stated that this supports the observation of the relative paucity of rights issues in the marketplace (the 'rights offer paradox').

Carlton also agreed with CEG, and using data from Eckbo, Masulis and Nori, documented the forms that indirect costs will take in a rights issue—including: tax effects; liquidity impact and transaction costs; risk of failure; arbitrage activity and short selling; and anti–dilution clauses to convertible security holders.[863]

The AER considers that each of these arguments is a sub–class of the general transaction cost and wealth transfer arguments that were analysed earlier in this appendix. The AER notes that although these factors may have some predictive ability when explaining the rights offer paradox, none of the perceived indirect costs form an appropriate basis for an equity raising cost allowance. This is the logic followed by Associate Professor Handley when he stated:[864]

> In my view, none of the above suggested indirect costs of a rights issue would warrant compensation.

The use of rights issues over placements

In the draft decision, the AER stated that a discounted rights issue should be the benchmark SEO method for determining equity raising costs.[865]

The NSPs contended that private placements were used more heavily than rights issues, and are therefore a more appropriate benchmark.[866] CEG, Carlton and Professor Grundy all argued that if profit–maximising firms choose placements as the most common means of equity raising, placements must therefore be the most efficient method of equity raising. Accordingly placement costs are the most efficient costs available from all SEO methods.[867] The NSPs' consultants stated that the AER should base the equity raising cost allowance on an estimate of the cost of a placement, including direct and indirect cost components.

The AER considers that, even if there was conclusive evidence that a particular method of equity raising was adopted by the majority of the market, this would not necessarily require the benchmark firm to adopt this method. In particular, since the characteristics of

---

861 Grundy, January 2009, p. 6, paragraphs 17–19.

862 Hansen, R. *The Demise of the Rights Issue,* The Review of Financial Studies, 1989, vol. 1(3), pp. 289–309.

863 Carlton, January 2009 (EnergyAustralia), pp. 8–9, section 1.1.3; and Carlton, January 2009 (TransGrid), pp. 19–20, section 2.1.3. Carlton notes that he did not independently verify the Eckbo, Masulis and Nori paper - see p. 4, footnote 4 (EnergyAustralia version).

864 Handley, April 2009, p. 21.

865 AER, *TransGrid draft decision*, p. 141; AER, *Transend draft decision*, p. 194; and AER, *NSW DNSP draft decision*, p. 191.

866 TransGrid, *Revised revenue proposal*, January 2009, p. 80.; EnergyAustralia, *Revised regulatory proposal*, January 2009, p. 44; CEG, January 2009, pp. 15–16, paragraph 44; Carlton, January 2009 (EnergyAustralia), pp. 2–7; and Grundy, January 2009, p. 7, paragraph 25.

867 CEG, January 2009, p. 17, paragraph 47; Carlton, January 2009 (EnergyAustralia), pp. 17–18, section 2.1; and Grundy, January 2009, p. 9, paragraphs 31–32.

the benchmark firm differ markedly from the market average, it is not necessary to automatically accept the average market method as appropriate. To accept the average methodology, the AER considers that empirical evidence regarding the equity choices of efficient firms similar to the benchmark firm would be necessary. The NSPs did not provide evidence regarding the propensity for a regulated Australian electricity network to use placements.

The AER notes that the conclusion that placements are more common than rights issues arises from an inappropriately narrow definition of rights issues by CEG, Carlton and Professor Grundy.[868] A rights issue is offered to existing shareholders in order to raise equity at a discount without diluting aggregate shareholder wealth. Any dividend reinvestment plan (DRP) is therefore effectively a periodic rights issue. This point was explicitly raised by Carlton, who stated in his report ‘it is important to observe that a DRP is effectively a non–renounceable rights issue.’[869] Associate Professor Handley also noted the essential equivalence of rights issues and DRPs.[870]

Comparison of all ‘rights based’ equity methods—considered as the sum of rights issues and DRPs—with private placements, reveals that, for Australian companies, placements are not preferred to offers made to existing shareholders. This is evident in table E.4, which is derived from data cited by both CEG and Carlton:

Table E.4: Total equity raised from 1991–2000 by method

	Rights issues	Reinvested dividends	Total rights based equity	Placements	Other methods[a]	Total
Total 1991–2000 ($m, 2000)	26.3	28.9	55.2	36.8	17.4	109.4
Percent of total (%)	24.0	26.4	50.4	33.6	16.0	100

Source: Based on Brown and Chan (2004), based on ASX Fact Book 2001.
(a) Other methods include options, calls, staff plans.

Table E.4 demonstrates that rights based equity raising is used in an absolute majority of cases (50.4 per cent) in the Australian market. It also demonstrates that equity raised through rights based equity issues is around 50 per cent larger than that raised through placements. Associate Professor Handley reviewed additional data from KPMG and found a similar pattern of results.[871]

In considering the appropriate allowance for equity raising costs, the AER has analysed recent equity raising activities of regulated utilities in Australia, and considered the potential reasons for undertaking an SEO.[872] The AER has found that equity raisings

868 CEG, January 2009, p. 15–16, paragraph 44; Carlton, January 2009 (EnergyAustralia), pp. 2–7; and Grundy, January 2009, p. 7, paragraph 25.
869 Carlton, January 2009 (EnergyAustralia), p. 29; Carlton, January 2009 (TransGrid), p. 36.
870 Handley, April 2009, p. 22.
871 Handley, April 2009, p. 23.
872 Sample included all equity raising activities between 1997 and 2008 for the following firms: DUET, AGL, AGL Energy, Origin, Babcock and Brown Power, SP AusNet, Alinta, Spark Infrastructure and Envestra. Data was collected from Bloomberg, annual reports, company releases and ASX announcements; initial public offerings were excluded.

often occur in order to fund organic growth of the business (internal expansion). In other cases, equity raising is required as a result of changes in business structure, business ownership or industry structure. Table E.5 provides the results of the AER's analysis.[872]

Table E.5: Equity raised by Australian utility firms 1997–2008 ($m)

Purpose of SEO	Mergers and acquisitions	Unidentified purpose	Internal expansion	Total
Placements				
Private placement	2482	431	66	2979
Share placement plan	306	115	54	475
Total placement	2788	546	120	3454
Rights based equity				
DRP	–	–	1453	1453
Rights issue	1577	600	–	2177
Total rights issue	1577	600	1453	3630
Employee shares	–	94	–	94
Total	4365	1240	1573	7178

Source: AER analysis.

While the majority of equity raising activity could be easily allocated to either internal expansion or merger activity, 17 per cent of equity raising activity either could not be allocated to any purpose, or was identified as partially supporting both internal expansion and mergers. Despite the difficulty in allocating this remaining equity, the AER considers the analysis indicates a relationship between equity raising methods and the purpose for which the equity is raised.

Table E.5 shows that while there are a significant number of rights issues, placements are more often chosen to support the majority of merger or acquisition activities. The AER considers that the significant changes in capital structure that occur during a merger or acquisition undermine comparisons with the benchmark firm, which is assumed to only undertake organic growth.[873] In addition, the costs of placements during a merger may be offset by the synergies expected to be generated by the merger itself. As such, the AER considers that the indirect costs of placements are likely to be offset by the indirect benefits of the changes in business structure.

Table E.5 also demonstrates that rights issues are chosen to support the majority of organic growth, with 92 per cent of all identified internal expansion funded via DRP. Placements are used infrequently for internal expansion (approximately 8 per cent of the time). The AER considers that this data, sourced from a sample of Australian regulated utilities over the past decade, provides a more appropriate comparison for the

[873] ACG, 2004, p. 4.

circumstances of the benchmark firm than any other empirical evidence submitted to it to date.

Non–price differences between placements and rights based equity

CEG stated that direct pricing for placements is consistently above that of rights issues.[874] CEG argued that no rational firm would willingly pay more than necessary for equity, and therefore inferred that there must be unobserved additional costs for a rights issue.

The AER considers that this argument ignores the existence of non–price differences between placements and rights issues. Placements are an exceedingly fast method to raise additional capital.[875] Empirical research indicates that placements are chosen as an equity raising method by firms under significant financial stress.[876] Such firms are not necessarily selecting equity raising methods on a least–cost basis. The financial stress of these firms requires urgent capital raising regardless of costs, and firms may in fact pay a premium to ensure the equity issue occurs quickly.[877] Accordingly, the AER considers that CEG has inappropriately assumed the existence of unobserved costs of a rights issue, and that equity raising trends may actually reflect the market value of non–price characteristics.

The AER has considered how the benchmark firm might value such a non–price characteristic of equity raising methods. The benchmark regulated firm experiences relatively predictable cash flows, low information asymmetry and a stable industry sector. The AER considers it is reasonable to expect that the benchmark firm's capital raising activities would occur in a planned and timely matter. Given reasonable management, the benchmark firm will not face financial stress that induces it to make decisions on a least–time basis. Rather, the AER considers the benchmark firm will prepare to raise capital as necessary, and elect equity raising methods generally according to least cost.

Associate Professor Handley also noted the range of factors (timing, equality, certainty of outcome and voting control) that are considered by a firm when choosing the benchmark SEO method, and observed that these indirect costs and benefits did have explanatory power.[878] On this basis, Associate Professor Handley noted the AER statement that a discounted rights issue was the optimal SEO method for all circumstances,[879] but did not consider it to be 'a strong argument' relative to arguments concerning consistency with the regulatory framework.[880]

In conclusion, the AER has considered the evidence presented by the NSPs and their consultants on the selection of a benchmark SEO method. The AER rejects the argument

874 CEG, January 2009, pp.16–17, paragraphs 45–47, and pp. 19–20, paragraphs 56–60. See also Grundy, January 2009, pp. 5–7, paragraphs 14–22.

875 Carlton, January 2009 (EnergyAustralia), p. 6; Carlton, January 2009 (TransGrid), p. 17.

876 Brown, P., Gallery, G. and Goei, O., *Does market misevaluation help explain share market long–run underperformance following a seasoned equity issue?*, Accounting and Finance, 2006, vol. 46, pp. 191–219. Bayless, M. and Chaplinsky, S. J., *Is There A Window of Opportunity for Seasoned Equity Issuance?*, Journal of Finance, 1996, vol. 51(1).

877 The AER notes that the price observed is not consistent with the efficient price outcome of both the seller and the buyer being unforced.

878 Handley, April 2009, p. 13.

879 AER, *TransGrid draft decision*, p. 141; AER, *Transend draft decision*, p. 194; and AER, *NSW DNSP draft decision*, p. 191.

880 Handley, April 2009, p. 13.

that placements should be the exclusive SEO method chosen by the benchmark firm for the following reasons:

- the benchmark firm should not necessarily adopt the equity raising method used by the majority of the market, as the benchmark firm differs systematically from the average market firm
- the AER's analysis indicates that placements are not the predominant equity raising method in the market. Rather, rights based methods (including DRPs and rights issues) jointly dominate the market
- close examination of Australian utilities demonstrates that placements are mostly used to fund mergers or acquisitions. Equity raising for organic growth, which is the most relevant scenario for the benchmark firm, is principally characterised by DRPs
- any time advantage of placements is irrelevant to the benchmark firm facing stable financials and efficient management.

On this basis, the AER considers that the appropriate benchmark equity raising method should not be restricted to placements. The AER notes that the recent update of the unit cost of SEOs based on the ACG methodology included both rights issues and placements.

Other issues

Announcement effects

The AER acknowledges the existence of alternative definitions of indirect costs in the financial literature.[881] There is frequently a change in a firm's share price when an equity raising is announced, often labelled as an 'announcement effect'. Some researchers identify this as an indirect cost of the equity raising, reasoning that the equity issue precipitated the change in price.[882] The AER notes that announcement effects are not considered an indirect cost by CEG, who stated:[883]

> If an announcement of equity raising signals to investors an unanticipated cash–flow problem at the firm then any consequent fall in the firm's share price cannot be presumed to be a cost of raising equity.

The AER notes that this is also the conclusion drawn by Associate Professor Handley, who stated:[884]

> It is noted that underpricing costs may be measured in a number of different ways, and further, that a reference to underpricing is not a reference to the stock price reaction that may occur on announcement of the security issue.

It is on this basis that CEG argued that Ofgem's rejection of indirect costs in their 2006 price control review[885] was a rejection of announcement effects, not underpricing, and therefore irrelevant to the CEG claim for indirect costs. CEG stated:[886]

---

881 Handley, April 2009, p. 5, footnote 9.

882 See Eckbo, B., Masulis, R. and Nori, O., *Security Offerings*; in Eckbo, B. (ed.), *Handbook of Corporate Finance*, Elsevier, 2007; cited by Handley, April 2009, p. 5, footnote 9.

883 CEG, *Memorandum*, February 2009, p. 2.

884 Handley, April 2009, p. 5.

885 OFGEM, *Transmission price control review: Final proposals*, 4 December 2006.

886 CEG, Memorandum, February 2009, p. 3.

> However, the basis of the empirical estimates of indirect costs in our report was, unlike the discussion in Smithers and Co, based on underpricing not announcement effects. That is, indirect cost estimates in our report were based on the difference between the price at which equity traded on the stock market and the price at which it was simultaneously issued to new investors.

The AER notes that Carlton frequently cited announcement effects when discussing the existence of indirect costs. For example:[887]

> The importance of take–up is demonstrated by the Balachandran et al results. They found that for rights issues where the subscription by existing shareholders was low the negative announcement period returns were –3.22%; these negative returns are economically significant, equating to about 6.5% of proceeds received. Firms with high levels of take–up recorded less negative returns of –0.63%.

The AER considers that the exclusion of announcement effects from the definition of indirect costs is appropriate. The AER notes the agreement on this matter by CEG.

Upward sloping supply of capital

The AER notes CEG's argument that the supply curve for capital is upward–sloping[888] implying that the AER should allow each NSP to continually increase returns to each set of new investors. This requires that the aggregate return to all investors would also increase over time, as the proportion of old investors decreases, and new investors receive ever–increasing returns. The AER notes that this would occur despite all parameters set under the NER and the transitional chapter 6 rules, (including beta, market risk premium, debt risk premium, gamma and gearing) remaining constant. The AER considers this outcome is incompatible with the regulatory framework mandated by the NEL and NER.

Information asymmetry

The AER notes empirical evidence of share price changes around the issuance of right–based equity, and notes the Hansen (1989) explanation that these changes are due to transaction costs being placed on shareholders. However, the AER recognises that there are other plausible explanations in the academic literature for this empirical evidence. This includes Eckbo and Masulis (1992), who consider Hansen's argument along with other explanations (information asymmetry and agency reasons) for the rights offer paradox.[889] Eckbo and Masulis conclude that there is 'insufficient evidence to suggest that any of these alternative explanations can resolve the rights offer paradox'.[890] This research is particularly relevant given that information asymmetry is one area in which regulated utilities differ markedly from the market average. The 'adverse selection' model developed by Eckbo and Masulis derives share price effects from market attempts to determine the 'true' value of the business. For a benchmark firm, this force is entirely absent (given that all cash flow projections are perfectly transparent and regulated). This research is strengthened by Bohren, Eckbo and Michalsen (1997) who present further

887 Carlton, January 2009 (EnergyAustralia), p. 10; Carlton, January 2009 (TransGrid), p. 22. See also Carlton, January 2009 (EnergyAustralia), pp. 7, 15, 16, 21; Carlton, January 2009 (TransGrid), pp. 18, 28, 35.

888 CEG, January 2009, p. 12, paragraph 32.

889 Eckbo, B. E. and Masulis, R. W., *Adverse selection and the rights offer paradox*, Journal of Financial Economics, 1992, vol. 32, pp. 293–332.

890 Eckbo and Masulis, 1992, p. 295.

evidence that information flows determine the presence and level of underpricing in rights issues.[891]

The AER also notes a large body of research observing that firms issue equity capital to outside investors—that is, a placement rather than a rights issue—when the share price is overvalued. This includes studies by Myers and Majluf (1984), Karpoff and Lee (1991), Spiess and Affleck–Graves (1995), Bayless and Chaplinsky (1996), Jindra (2000), and Brown, Gallery and Goei (2006).[892] Importantly, this means that the observed placement underpricing is not actually a true cost to original investors, since the reduction in prices accompanying an equity raising simply returns their shares to their true worth. The outside investors, although paying a discount to the temporarily overvalued price, have still contributed the true worth of their share, and there is therefore no dilution effect for the original shareholders. Heron and Lie (2004) extend this argument by arguing that managers issue shares to outside investors (via placement) when overvalued and rights issues when undervalued. The authors conclude that a possible reason for low usage of rights issues in the US may be that the major motivation for equity raising is to sell equity when it is overvalued.

Cost of using retained earnings

The NSPs stated that the marginal cost of using retained earnings has not been considered by the AER, and for this reason the AER had underestimated the cost of raising equity.[893] CEG and Professor Grundy identified five reasons why using retained earnings as equity incurs costs:

- increasing retained earnings lowers the ability to distribute dividends, which therefore lowers the ability to distribute imputation credits to investors[894]
- use of retained earnings lowers the ability to distribute dividends, which causes the firm to deviate from the dividend expected by the current 'dividend clientele', who will react negatively to the firm's behaviour[895]
- using retained earnings avoids the public scrutiny associated with external equity raising, and this public scrutiny is valuable to the business as a signal to the market of the quality of the firm[896]
- use of retained earning delays cash flows to investors, which increases risk[897]

---

891 Bohren, O., Eckbo, B. E. and Michalsen, D., *Why underwrite rights offerings? Some new evidence*, Journal of Financial Economics, 1997, vol. 46(2), pp. 223–261.

892 Myers, S. C. and Majluf, N. S., *Corporate financing and investment decisions when firms have information that investors do not have*, Journal of Financial Economics, 1984, Volume 13(2), pp. 187–221; Karpoff, J. M. and Lee, D., *Insider Trading Before New Issue Announcements,* Financial Management, Spring 1991, vol. 20(1); Spiess, K. D. and Affleck–Graves, J., *Underperformance in long–run stock returns following seasoned equity offerings*, Journal of Financial Economics, 1995, vol. 38(3), pp. 243–267; Bayless, M. and Chaplinsky, S. J., *Is There A Window of Opportunity for Seasoned Equity Issuance?,* Journal of Finance, March 1996, vol. 51(1); Jindra, J., *Seasoned Equity Offerings, Overvaluation, and Timing*, 2000; and Brown, P., Gallery, G. and Goei, O., *Does market misevaluation help explain share market long–run underperformance following a seasoned equity issue*?, Accounting and Finance, 2006, vol. 46, pp. 191–219.

893 TransGrid, *Revised revenue proposal*, p. 81; Integral Energy, *Revised regulatory proposal*, p. 45; EnergyAustralia, *Revised regulatory proposal*, p. 48.

894 CEG, January 2009, p. 29, paragraph 96 and Grundy, January 2009, p. 10, paragraph 36.

895 Grundy, January 2009, p. 9, paragraph 34.

896 CEG, January 2009, pp. 29–30, paragraph 97; Grundy, January 2009, p. 10, paragraph 35.

- use of retained earnings forces existing shareholders to reinvest in the firm, deviating from their preferred portfolio and incurring transaction costs or increases in risk from a loss of diversification.[898]

Accordingly, the NSPs' consultants proposed that a retained earnings allowance needs to be provided to the benchmark firm.[899] In arguing for this allowance, CEG reasoned that the first dollar of retained earnings had a marginal cost of zero. CEG considered that the marginal cost of each dollar remained zero, until the point at which the amount of retained earnings impacted negatively on the business, principally by reducing dividends below the normal dividend yield. At the point where external equity was preferred to the use of retained earnings, the marginal cost of each form of equity is assumed to be equal. Assuming a linear increase from zero to the cost of an SEO, CEG argued that the retained earnings allowance for the NSPs should be equal to half the unit cost of the SEO allowance. This allowance would be calculated only on the portion of retained earnings that negatively impact the firm.

The AER notes that this issue was not raised by any of the NSPs in their regulatory proposals, but is a new argument presented in the revised regulatory proposals.

The AER is not aware of any regulatory precedent for applying a cost to retained earnings. ACG stated in its 2004 report:[900]

> Retained earnings have no issue costs and are generally undertaken continuously by regulated entities.

Associate Professor Handley considered each of the arguments raised by the NSPs, and rejected them as either an inappropriate basis for an allowance—for instance, personal transaction costs—or as being adequately dealt with in the discounting process (cash flow profiles through WACC, and imputation credit distribution through gamma). Associate Professor Handley argued that although selection of optimal dividend yield was required for determination of external equity requirements, there was no consequent cost for use of retained earnings, and concluded:[901]

> In summary, it is my view that indirect costs associated with using retained earnings should not be allowed as a cost of raising equity capital.

The AER considers that the NSPs have not provided evidence that there is a cost to the benchmark firm from using retained earnings.

Theoretical consideration of retained earnings cost allowance

The AER agrees with CEG that the pecking order theory does not state explicitly that retained earnings always have zero marginal cost.[902] However, the AER considers that CEG's arguments for a retained earnings allowance do not stand up to scrutiny.

CEG and Professor Grundy argued that retained earnings incur a cost to the benchmark firm because they impair the distribution of imputation credits.[903] The AER notes that,

---

897 CEG, January 2009, p. 30, paragraph 99.
898 CEG, January 2009, p. 30, paragraph 100.
899 CEG, January 2009, pp. 31–34, paragraphs 101–115.
900 ACG, 2004, p. 63.
901 Handley, April 2009, p. 19.
902 CEG, January 2009, p. 32, paragraph 105.

since the benchmark equity raising cost cash flow analysis takes account of an appropriate level of benchmark dividends, no such cost of using retained earnings is incurred by the NSP.

Professor Grundy argued that the established dividend clientele would react negatively to a change in dividend levels as a result of increased retained earnings.[904] The AER does not consider that the assumptions concerning benchmark dividends in the benchmark equity raising cost cash flow analysis would result in any negative affect on the purported dividend clientele. Further detail on the AER's assessment of benchmark dividends is discussed below in this appendix.

CEG and Professor Grundy also argued that public scrutiny associated with external equity raising reduces costs to the benchmark firm.[905] The AER considers that this does not apply in the context of a regulated firm whose financial decisions are transparent, regardless of a specific equity issue. Accordingly, the AER considers that this proposed marginal cost of using retained earnings is not applicable in the context of the benchmark firm.

CEG also argued that the backdating of cash flows (via retained earnings) results in increased risk, and therefore, increased cost.[906] The AER considers that this result is dependent on the delayed distribution of dividends, in both the initial and later years of the next regulatory control period. However, the AER notes that dividends are set, independent from the size of retained earnings. For each year, the benchmark dividend has been determined according to the amount of imputation credits earned in the post–tax revenue model (PTRM) (based on the relevant gamma), prior to deriving retained earnings.

In addition, the AER notes that such a risk increase applies regardless of the source of equity, since it is only dependent on the schedule of payments involved. All investment projects undertaken by the benchmark firm involve initial payments to establish infrastructure, which then return in later years (i.e. a 'backdated cash flow'). All projects would therefore add to 'interest rate risk'. The AER considers a proposed retained earnings allowance would, in effect, allow for NSPs to earn a higher rate of return. The AER consideration of the rate of return is set out in chapter 12 of this final decision.

CEG argued that use of retained earnings incurs costs associated with disrupting investors' preferred portfolios.[907] The AER notes that this is an argument regarding personal transaction costs, and that such arguments were considered in detail earlier in this appendix. The AER considers that no evidence has been provided that the overall transaction costs incurred by investing in a benchmark firm, even with a 'forced transaction,' would exceed the transaction costs from investing in the market portfolio.

The AER considers that the arguments concerning the implementation of a retained earnings allowance, as proposed by CEG, are flawed for the following reasons:

903 CEG, January 2009, p. 29, paragraph 96 and Grundy, January 2009, p. 10, paragraph 36.
904 Grundy, January 2009, p. 9, paragraph 34.
905 CEG, January 2009, pp. 29–30, paragraph 97; Grundy, January 2009, p. 10, paragraph 35.
906 CEG, January 2009, p. 30, paragraph 99.
907 CEG, January 2009, p. 30, paragraph 100.

- the linear marginal cost increase from zero per cent to the cost of an SEO cannot be justified
- the average area under the (linear) marginal cost curve is overestimated by the half–of–SEO–percentage rule proposed by CEG
- the selection of the boundary points (minimal dividend yield and normal dividend yield) is contentious.

The AER notes that these flaws are cumulative in effect. The AER considers that, even if such an allowance was theoretically justified, the practical implementation proposed by CEG does not accurately measure the theoretical concept.

Conclusion on cost of using retained earnings

The AER has considered the evidence presented by the NSPs and their consultants on the cost of using retained earnings as a source of equity. The AER finds three key reasons to reject the proposals for a retained earnings cost allowance, each of which it considers are independently sufficient to reject the proposal:

- new methodology cannot be presented by an NSP in its revised revenue proposal
- there is no acceptable theoretical justification for a retained earnings cost allowance
- the implementation proposed by CEG systematically overestimates what it purports to measure and cannot be accepted as an accurate methodology.

On this basis, the AER rejects the claim for an allowance for the cost of using retained earnings.

Direct cost of raising equity

In previous transmission determinations, the AER has based its estimate of the direct cost of raising equity on the ACG methodology, which recommended a benchmark transaction cost of 3 per cent of the total equity raised.[908] ACG based this unit cost on an analysis of actual SEO raising costs (rights issues and placements) incurred by Australian companies between 1998 and 2004, noting the difficulty obtaining data from firms with characteristics matching that of the benchmark firm (regulated utilities who require funds for internal expansion). With this in mind, ACG adopted the 3 per cent as a conservative estimate, noting that it was 'an upper limit of the likely cost of an SEO associated with capital expenditure within existing regulated activities'.[909] This figure was updated by the AER in 2008, consistent with the ACG methodology, to 2.75 per cent.[910] The ACG methodology only includes rights issues and placements; it does not include dividend reinvestment plans.

The NSPs disputed the draft decision on direct equity raising costs but did not present an alternative unit cost in their revised regulatory proposals.[911] This is in keeping with the NSPs' expressed view that the direct and indirect costs of all capital raising are interdependent and should be jointly decided, and the re–submission of a combined unit

908 ACG, 2004, pp. 64–69.
909 ACG, 2004, p. 65.
910 AER, *NSW DNSP draft decision*, p. 197, footnote 549.
911 TransGrid, *Revised revenue proposal*, pp. 79–82; EnergyAustralia, *Revised regulatory proposal*, pp. 44–47.

cost of 7.6 per cent.[912] CEG decomposed the 7.6 per cent unit cost in its May 2008 report:[913]

> We recommend adopting an estimate of 7.6%. This is approximately the same result as adding Bortolotti, Megginson and Smart's estimate of average global underpricing (4.5%) to the AER's current estimate of direct costs (3%). It is also consistent with the 7.6% estimate of total costs based on the work of Saunders, Palia and Kim (2003). It is also consistent with Lee Lochead and Ritter [sic] (1996) estimate of direct SEO costs for utilities (4.9%) plus the lowest available estimate for underpricing in SEOs (2.5% based on US estimates by Bortolotti et. al.)

The AER notes that the paper by Lee, Lochhead, Ritter and Zhao considers only domestic US firms raising capital in the US market. Accordingly, it is of limited relevance to the benchmark Australian firm raising equity in Australia.[914] Further, the AER notes that Lee et al excludes all rights issues, skewing the obtained estimate of direct costs by the elimination of a significant portion of SEOs. On this basis, the AER considers that the Lee, Lochhead, Ritter and Zhao estimate of direct equity raising costs is not relevant to the benchmark regulated firm in Australia.

No other breakdown of direct costs was provided in the January 2009 CEG report, the report by Professor Grundy or the Carlton report.

Associate Professor Handley noted the acceptance by the NSPs of the 3 per cent unit cost based on the ACG methodology. Associate Professor Handley suggested that a reasonable estimate of the direct cost of raising equity capital from placements and other sources (other than dividend reinvestment plans) was in the range 2.75–3 per cent.[915]

On the basis of its review and assessment of all the material put forward, the AER considers that an allowance of 2.75 per cent, based upon the ACG methodology is an appropriate unit cost for direct equity raising costs (other than DRPs).

Implications of the Ofgem decision

CEG argued that the consideration of Ofgem (the UK regulator) precedent should lead to an allowance of 5 per cent for direct equity raising costs,[916] since this was the final unit cost approved by Ofgem in its 2006 price control review.[917]

The AER observes that Ofgem was interested in firms in the United Kingdom when it assessed direct equity raising costs and established a market range of 5–12 per cent. The AER notes that research papers repeatedly find large differences between nations on equity raising costs.[918] Accordingly, in view of the numerous differences in economic, financial and regulatory frameworks between the two countries, the AER does not

---

912 TransGrid, *Revised revenue proposal*, p. 82; EnergyAustralia, *Revised regulatory proposal*, p. 49.

913 CEG; May 2008 (TransGrid), p. 25, paragraph 84; CEG, April 2008 (Integral Energy), p. 25, paragraph 85; CEG, November 2008 (JIA), p. 27, paragraph 96.

914 Lee, I., Lochhead, S., Ritter, J. and Zhao, Q., *The Costs of Raising Capital*, The Journal of Financial Research, vol. 19(1), pp. 59–74.

915 Handley, April 2009, p. 26.

916 CEG, *Memorandum*, February 2009, p. 2.

917 OFGEM, *Transmission price control review: Final proposals*, 4 December 2006.

918 For example, Chen, H. and Ritter, J., *The Seven Percent Solution*, Journal of Finance, June 1999; Gajewski, J. and Ginglinger, E. *Seasoned Equity Issues in a Closely Held Market: Evidence from France*, European Finance Review, 2002, Vol 6, pp. 291–319.

consider it appropriate to apply direct cost estimates from the United Kingdom to Australian firms.

The AER considers, however, that Ofgem's reasoning regarding the positioning of regulated utilities relative to average market position on equity raising costs is relevant. In both Australia and the UK, regulated utilities have lower information asymmetry, more stable cash flows and better known risk than the market average. Therefore, it is likely that the direct equity raising cost of regulated utilities will be systematically lower than the market wide average direct equity raising cost. This means that although the Ofgem range of 5–12 per cent is not relevant, the Ofgem policy of choosing the lower limit of the range may be of relevance for the AER when positioning likely benchmark direct equity raising costs of regulated utilities relative to the market average equity raising costs.

Benchmark cash flow analysis—calculation of retained earnings and external equity requirements

In order to determine the amount of equity raising required in recent transmission determinations, the AER has undertaken an assessment of benchmark cash flows calculated in the PTRM. In summary, the analysis calculated the amount of retained earnings which was deducted from the equity portion of forecast capex. The resultant figure, if positive, represented the amount of new equity to be raised.

The NSPs submitted that the benchmark cash flow analysis applied in the draft decision was flawed because consistency was not maintained with the regulatory benchmarks in the PTRM.[919] The issues identified by the NSPs and their consultants included:[920]

- the calculation and assumptions surrounding dividends including the measurement of net profit, payout ratios, implied dividend yields and distribution of imputation credits
- the lack of provision to repay the principal of existing debt.

Citing findings from a review by KPMG, Integral Energy made the following submission:[921]

> The PTRM does not provide sufficient cash flows to enable Integral Energy to pay out a level of dividends and associated imputation credits that is sufficient to support the value that is assumed to flow to shareholders from imputation credits. Under such circumstances the cash flow to equity providers will be lower than that assumed in the PTRM, resulting in a calculated return to equity holders that is lower than the benchmark cost of equity assumed in the inputs; and
>
> The value of imputation credits that is assumed to flow to shareholders in the PTRM can only be supported if dividend payout ratios well in excess of 100% is assumed each year. Even with a 100% dividend payout ratio, there are insufficient accounting profits available to distribute the required level of dividends and imputation credits.

919 A broad outline of the steps in the AER's benchmark equity raising cash flow analysis can be seen on page 142–143 of the draft decision on TransGrid's revenue proposal. These steps largely remain valid despite the issues considered in this final decision. Where the steps set out in the draft decision are no longer accurate, specific changes to the methodology are set out in this appendix.

920 For example, TransGrid, *Revised revenue proposal*, pp 80–81; EnergyAustralia, *Revised regulatory proposal*, pp. 47–48.

921 Integral Energy, ***Submission,*** p. 10.

Each of these issues is considered below, in addition to other cash flow issues identified by the AER.

Assessment of dividends

The AER's benchmark equity raising cash flow analysis includes an assessment of dividends that are to be subtracted from internal cash flows in the process of calculating the amount of retained earnings that is available for reinvestment through forecast capex. As the equity raising cash flow analysis is not part of the PTRM, the assumptions concerning dividends do not directly affect any cash flows in the PTRM (other than the allowance provided for equity raising costs).[922] However, as the AER has applied a benchmark approach to determining the appropriate allowance for equity raising costs,[923] it agrees with Associate Professor Handley that assumptions should be consistent with the overall regulatory framework.[924]

The NSPs noted that the effective dividend yield assumed in the draft decision was less than 3 per cent.[925] The NSPs submitted that a dividend yield of 8.6 per cent is sustainable in the long–run provided it is less than the return on equity.[926] TransGrid also stated that equity holders expect to receive their return on equity as dividends.[927] CEG was critical of the assumptions concerning the appropriate amount of dividends. While advocating a long–term benchmark dividend yield (rather than a payout ratio), CEG concluded that:[928]

> The appropriate dividend policy should be determined by reference to the level of economic profit. It cannot sensible [sic] be determined by reference to accounting profit (except where this is the best estimate of economic profit).

TransGrid and EnergyAustralia also submitted a report by Carlton which supported an alternative dividend policy based on 100 per cent distribution of imputation credits.[929] TransGrid and EnergyAustralia did not apply the recommendations of the report by Carlton, but suggested that there is merit in further review of his recommended approach.[930]

Integral Energy submitted that the inconsistency between the PTRM and the benchmark equity raising cash flow analysis was attributable to different measures of depreciation:[931]

> The net profit after tax is clearly inconsistent with the face value of imputation credits created for the same time period. This is evidence of the effect that

922 Accordingly, claims by NSPs about the impact of the AER's cash flow analysis on returns to equity holders and the level of imputation credits that can be distributed, are only relevant to the consideration of the appropriate allowance for equity raising transaction costs. That is, the cash flow analysis and assumptions do not affect the PTRM or any of the building block calculations apart from the allowance for equity raising transaction costs.

923 This is in contrast to a direct estimate of the likely costs to be incurred by the regulated business, which in this case is likely to be negligible due to government ownership.

924 Handley, April 2009, pp. 30–33.

925 TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

926 TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

927 TransGrid, *Revised revenue proposal*, p. 81.

928 CEG, January 2009, p. 28.

929 Carlton, January 2009 (EnergyAustralia), pp. 27–29, section 3.2.

930 TransGrid, *Revised revenue proposal*, p. 82.

931 Integral Energy, *Submission*, Attachment 3, p. 3.

> incorporating income taxation, financial accounting and economic value within the PTRM can result in differing views of the same "transactions".
>
> The obvious difference between these three views of financial performance as represented in the PTRM relates to the calculation, application and timing of "depreciation".

Despite raising the concerns supported by it consultants' reports, in their revised regulatory proposals TransGrid, EnergyAustralia and Integral Energy applied dividend assumptions that were consistent with the draft decision. However, given the concerns and criticisms raised by the NSPs regarding the assumptions about dividends, the AER has given further consideration to this issue.

The PTRM, by design, does not include an assessment of dividends. However, the AER is required by the NER to assume a certain level of utilisation of imputation credits for a benchmark efficient entity when calculating the allowance for corporate income tax.[932] Ultimately, the value of imputation credits can only be realised in the hands of shareholders who may receive imputation credits attached to dividend payments. Accordingly, an issue of consistency arises between the assumed value of imputation credits in the PTRM and the amount of imputation credits that is assumed to be distributed in the AER's benchmark equity raising cash flow analysis.

As noted by Carlton, however, the level of dividends in the equity raising cash flow analysis in the draft decision was generally insufficient to distribute the amount of imputation credits assumed in the PTRM.[933] The dividends assumed in the draft decision were based on a 70 per cent payout ratio applied to accounting net profit after tax. Under the approach applied in the draft decision the degree to which imputation credits were distributed through dividends varied over time and between the businesses.

As required by the NER, the PTRM reduces the allowance for tax based on the assumption that investors receive a value for imputation credits equal to gamma (0.5) times the value of taxes payable. If sufficient imputation credits are not distributed via dividends for this to be achieved and shareholders receive less than the assumed benefit from imputation credits, then the PTRM will not achieve the design objective of providing investors with the expectation of achieving the benchmark return on equity.[934]

Accordingly, to maintain consistency between the assumptions and analysis of the PTRM, the AER considers it appropriate to amend the way dividends are derived in its benchmark equity raising cash flow analysis for this final decision. The AER considers that the approach advocated by Carlton—linking dividends to the amount of imputation credits calculated in the PTRM—has merit. However, the AER does not agree with all of the cash flow assumptions made by Carlton. In particular, the AER considers that the

---

932 NER, clause 6A.5.3.

933 Carlton, January 2009 (EnergyAustralia), p. 26. See also KPMG, January 2009, pp. 10–11.

934 Under the National Tax Equivalence Regime, the government owned business makes tax equivalent payments to the government (the tax collector as well as the shareholder). While the shareholder may also receive dividends, in this instance it is not able to make any use of imputation credits. It does however receive the full value of tax equivalent payments made (to itself), which is equivalent to a privately owned firm receiving the full value of the potential imputation credits regardless of whether there is any dividend or not. In fact, regardless of the assumed value of gamma, the return to the government will be the same. Therefore the assumed dividend payout in this instance cannot compromise the intended benefits of imputation credits to these shareholders.

required payout ratio of imputation credits to achieve the value in the PTRM has been misunderstood.

Background to gamma estimate in the NER

In the draft decision, the AER determined that an imputation credit payout ratio estimated for the purposes of the gamma parameter (i.e. assumed utilisation of imputation credits) can provide a reasonable estimate of a dividend payout ratio to be used for the purposes of estimating equity raising costs.[935] In the draft decision, the AER stated that a 70 per cent dividend payout ratio is considered as consistent with clause 6A.6.4(a) of the NER and clause 6.5.3 of transitional chapter 6 rules, which deems the utilisation of imputation credits to be 0.5.[936]

This observation was made in the ACCC's TransGrid 2004 draft decision,[937] which informed its view that the assumed utilisation of imputation credits be 0.5 in the 2004 Statement of Regulatory Principles (SRP).[938] The Statement of Regulatory principles subsequently formed the basis of the NER requirement for a gamma of 0.5. Specifically, the ACCC stated that estimates of the average value of imputation credits once distributed, ranged between 50 and 90 per cent.[939] The decision also cited an average dividend payout ratio of approximately 70 per cent before concluding that the gamma value should be 0.5.[940] It is apparent that this conclusion is the product of approximately 70 per cent payout ratio and approximately 70 per cent average valuation (around the middle of the stated range).

The AER's WACC review

In December 2008, the AER proposed that the assumed utilisation of imputation credits (i.e. gamma) be increased from 0.5 to 0.65.[941] One of the key assumptions supporting the AER's proposed position on gamma was an imputation credit payout ratio of 100 per cent, following the recommendation of the AER's consultant, Associate Professor Handley. In his report Associate Professor Handley argued that:[942]

> …the generally accepted approach by regulators is to define the value of imputation credits as the product of a credit distribution or payout ratio – representing the proportion of credits generated that are distributed to shareholders, and a credit utilisation or redemption rate – representing the value of a distributed credit…
>
> An alternative view is that a decomposition of gamma along these lines is unnecessary since, for valuation purposes, it is appropriate to assume the distribution ratio is equal to one.

---

935 It is noted that these two payout ratios may not necessarily coincide, as in practice there are methods available to distribute imputation credits other than by attachment to a normal declared dividend (for example, special dividends, off-market share buybacks and DRPs). See AER, *Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters: Explanatory Statement*, 12 December 2008, p. 301.

936 AER, *NSW DNSP draft decision*, p. 195, footnote 547.

937 ACCC, *NSW and ACT Transmission Network Revenue Caps– TransGrid 2004/05–2008/09: Draft decision*, 28 April 2004, pp. 87–88.

938 ACCC, *Statement of principles for the regulation of electricity transmission revenues: Decision*, 8 December 2004, p. 17, point 8.9.

939 ACCC, *TransGrid draft decision*, April 2004, p. 87.

940 ACCC, *TransGrid draft decision*, April 2004, p. 87, footnote 54.

941 AER, *WACC review: Explanatory statement*, 12 December 2008, pp. 13–14.

942 Handley, J.C., *A note on the valuation of imputation credits*, 12 November 2008, p. 4.

As noted above, the AER stated in its draft decision that the assumed payout ratio of 70 per cent was consistent with the gamma estimate of 0.5 specified by the NER. That is, the estimate of a gamma of 0.5 in the NER was the product of an assumed payout ratio and an assumed utilisation rate.[943] However, Carlton suggested that the payout assumption is required to be 100 per cent citing the AER's WACC explanatory statement that indicates an assumption that 100 per cent of imputation credits are paid out.[944] A similar view was put forward by SFG and KPMG.[945]

The AER does not accept this argument for the purposes of this final decision. As Associate Professor Handley articulates in his report, the assumption of a payout ratio of 100 per cent for valuation purposes represents a departure from the 'generally accepted regulatory practice', which effectively assumes a zero value for retained imputation credits (i.e. 'the Monkhouse approach'). As the prescribed gamma value of 0.5 was estimated on the basis of the Monkhouse approach, the views received from Associate Professor Handley as part of the WACC review are not a relevant consideration for the purposes of this final decision.

The AER maintains that the imputation credit payout ratio assumed for the purposes of estimating the gamma parameter required under the NER provides a reasonable estimate of the dividend payout ratio to be used for the purposes of estimating equity raising costs under the cash flow analysis. Accordingly, the AER considers that a payout ratio of 70 per cent is appropriate for the purposes of this final decision.

Consideration of methodology for setting dividends

The AER notes the criticism concerning the apparent disconnect between the PTRM valuation of imputation credits and the value shareholders would actually receive under the draft decision.[946] Carlton stated that for EnergyAustralia, the AER had assumed imputation credits of $292 million in the PTRM while shareholders would only be able to realise a value of $130 million through assumed dividends.

This apparent disconnect arises from two sources. The first relates to the assumption about the value of a distributed imputation credit. Carlton's assumed payout ratio of 100 per cent, to achieve a gamma value of 0.5, relies on 50 per cent utilisation by shareholders. Conversely, as set out above, the AER has indicated that a gamma value of 0.5 is consistent with a payout ratio of about 70 per cent, and about 70 per cent utilisation by shareholders. Adjusting for this misinterpretation of the gamma estimate in the NER, the comparison becomes $292 million in the PTRM and about $182 million ($260 million × 70 per cent) for the realised value of distributed imputation credits under the benchmark equity raising cost cash flow analysis.[947] However, Carlton's point remains valid. That is, imputation credits assumed in the PTRM are greater than the assumed distribution and subsequent valuation of imputation credits within the benchmark equity raising cost cash flow analysis.

943 The product of ~0.7 (payout ratio) and ~0.7 (utilisation) is 0.5, consistent with the required gamma value specified in the NER.

944 Carlton, January 2009 (EnergyAustralia), p. 26; Carlton, January 2009 (TransGrid), pp. 5–6.

945 SFG, March 2009, pp. 14–15, paragraphs 58–61; KPMG, January 2009, p. 2.

946 Carlton, January 2009 (EnergyAustralia), pp. 23–26, section 3.1.

947 The figure of $260 million is the amount of imputation credits that could be distributed through dividends assumed in the draft decision benchmark equity raising cash flow analysis.

Accordingly, to address the issue in its equity raising cash flow analysis, the AER has assumed that dividends are equal to the amount required to distribute 70 per cent of total imputation credits assumed to be earned in the PTRM (total imputation credits earned is equivalent to tax paid). This amount is calculated according to the formula:

$$\text{Dividends} = \left(\frac{\text{Imputation credits earned}}{\text{tax rate}}\right) \times \left(1 - \text{tax rate}\right) \times \text{payout ratio}$$

The AER's amendment to the dividend policy applied in the draft decision rectifies the remaining disconnect between the value assumed for imputation credits in the PTRM and in the benchmark equity raising cash flow analysis. The AER has confirmed that for each of the relevant NSPs, the assumed value of imputation credits in the PTRM is consistent with the value realised by shareholders (after being distributed with dividends and utilised by shareholders).[948] This is consistent with the derivation of the gamma value specified in the NER of 0.5.

The AER notes that the dividend yield implied by this approach will vary from business to business and year to year, as it is driven by the amount of the tax building block in the PTRM relative to the RAB. However, the AER considers that consistency between the assumptions made in the PTRM and in the equity raising cash flow analysis is of greater importance than the implied dividend yield in this instance.

Inclusion of a dividend reinvestment plan

The AER's estimate of benchmark equity raising costs for recent transmission determinations has been based on the ACG methodology. However the AER has not taken DRPs into account. To the extent that the cost of raising equity through DRPs[949] is less than the benchmark cost applied in the ACG methodology, the AER's recent determinations have overstated the appropriate cost of raising equity through DRPs. The AER applied a benchmark direct unit cost of 2.75 per cent in its draft decision. While Carlton has suggested that indirect costs associated with DRPs should be taken into account,[950] as discussed above, the AER considers that an allowance for such costs would be inappropriate. This view is supported by Associate Professor Handley.[951]

Direct costs of equity raised through a dividend reinvestment plan

The ACG suggested that the costs of raising equity should be zero. ACG noted that even when DRPs are underwritten, the level of competition among brokers resulted in no cost for underwriting services as brokers sought to profit by placing stock at a higher price than the standard DRP price.[952] Carlton stated that anecdotal evidence suggests that underwriting fees of around 2.5 per cent are being charged for DRP underwriting.[953] On the basis of the ACG and Carlton estimates, Associate Professor Handley stated that a reasonable estimate of the cost of a DRP is between zero and 2.5 per cent.[954]

---

948 For the amounts to precisely equate, the assumed utilisation of imputation credits by shareholders is calculated to be 71 per cent.

949 ACG suggested that the cost of raising equity through a DRP should be zero. ACG, 2004, p. 63.

950 Carlton, January 2009 (EnergyAustralia), pp. 29–30; Carlton, January 2009 (TransGrid), pp. 35–36.

951 Handley, April 2009, pp. 23–24.

952 ACG, 2004, p. 63.

953 Carlton, January 2009 (EnergyAustralia), pp. 29–30; Carlton, January 2009 (TransGrid), p. 36.

954 Handley, April 2009, pp. 26–27.

However further investigation of Carlton's anecdotal evidence reveals that the figure of 2.5 per cent was only applicable to the portion of equity taken up by the underwriter. In this instance the take up by the underwriter was about half of the capital raised which, in turn, implies that the underwriting cost as a percentage of equity raised is about half of 2.5 per cent.[955]

The AER has undertaken its own research of the costs of DRPs among domestic energy network businesses. The AER observed that where reported, costs as a portion of equity raised had a median of 0.75 per cent and a mean of 1 per cent.[956] On the basis of all the information considered including the ACG report and Carlton's anecdotal evidence, the AER considers that a conservative estimate of 1 per cent is appropriate. The AER considers that this figure is the appropriate unit cost to be applied to the amount of equity assumed to be raised through a DRP.

Amount of equity assumed to be raised through a dividend reinvestment plan

Associate Professor Handley advised that a reasonable estimate of the amount of equity to be raised by a DRP was 30 per cent. This was based on the observation of the equity raised through DRPs in the Australian market.[957] However, the ACG and Carlton support an estimate of 30 per cent reinvestment of dividends.[958] To reiterate, Associate Professor Handley suggested applying the percentage to required equity, while the ACG and Carlton suggested applying the percentage to the amount of dividends paid. Carlton included data from selected DRPs with an average of 34 per cent reinvestment of dividends.[959] The AER analysed data for Australian energy network businesses and found that about 30 per cent of dividends distributed were returned through a DRP.[960]

On balance the AER considers that it is reasonable to assume that the amount of equity to be raised by a DRP is 30 per cent of dividends paid. Whether this is greater or less than the approach considered reasonable by Associate Professor Handley will depend on the relative magnitude of dividends paid and required equity.[961] However, the AER considers it appropriate to link the level of dividend reinvestment to the assumed dividend payout rather than the total equity required. This will ensure that the assumptions within the equity raising cash flow analysis are internally consistent.

Accordingly, in its benchmark equity raising cash flow analysis the AER has assumed that 30 per cent of dividends paid are available for reinvestment at a cost of 1 per cent. Any further requirement for equity is assumed to come from external sources at a cost of 2.75 per cent as discussed above.

955 Carlton, January 2009 (EnergyAustralia), pp.–41, appendix 4; Carlton, January 2009 (TransGrid), p. 49. The AER notes that 44 percent of dividends were reinvested with the underwriter taking up 22.6 per cent.

956 AER assessment of Bloomberg data and annual reports.

957 Handley, April 2009, pp. 23 and 26.

958 Carlton, January 2009 (TransGrid), p.36; ACG, 2004, p. 63.

959 Carlton, January 2009 (TransGrid), pp. 48–49.

960 AER assessment of data sourced from Bloomberg.

961 Further, while unlikely, where the DRP amount is linked to required equity, a scenario in which proposed capex is relatively high and taxes are relatively low could result in the amount of equity assumed to be sourced from DRP in excess of dividend payments.

Lack of provision for the repayment of existing debt

The NSPs applied a negative adjustment to retained earnings to allow for the repayment of debt. The justification for the adjustment is that it is required to maintain the benchmark gearing ratio.[962]

The NER requires the AER to set a WACC for the regulatory control period which includes setting the nominal risk–free rate and the debt risk premium, both with reference to bonds with maturity of 10 years. Under this framework, debt is assumed to be refinanced by the benchmark firm for each regulatory control period. Such financing arrangements do not include any presumption of debt repayment during that period.

However, the PTRM does assume that the level of debt varies from year to year in accordance with movements in the RAB. That is, when the RAB increases, so does the benchmark level of debt along with the benchmark return on debt (interest payments). As the NSPs' RABs are increasing over the next regulatory control period, the AER considers that the benchmark level of debt should increase, not decrease (repayment of debt would decrease debt). This can be seen in the row of the analysis sheet of the PTRM titled 'Repayment of debt'. The fact that this cell contains a negative number in each year of the next regulatory control period confirms that the level of debt is increasing rather than decreasing. Accordingly, the AER considers that the adjustment labelled as repayment of debt is potentially misleading.

The NSPs' justification for its amendment to include repayment of debt into the cash flow analysis was to maintain the benchmark gearing assumption in the PTRM.[963] While not explicitly required by the NER, as discussed above in the context of setting the dividend assumptions, the AER considers it appropriate that the equity raising cash flow analysis aligns with the benchmark gearing assumption required in determining the WACC (and applied in the PTRM). The AER's cash flow analysis for the draft decision has assumed that 60 per cent of capex would be funded by new debt. This appears to be consistent with the benchmark gearing specified in the NER. However, to maintain benchmark levels of gearing, the level of debt must equal 60 per cent of the RAB value (rather than 60 per cent of capex).

Accordingly, to maintain consistency between the benchmark equity raising cash flow analysis and the PTRM, where the RAB increase is less than the expected capex (due to regulatory depreciation), the increase in debt must be less than 60 per cent of capex. Put another way, the amount of capex funded by debt is constrained by the amount of the increase in the debt portion of the RAB. The AER has amended the cash flow analysis from its draft decision such that the increase in debt funding is linked to the row of the analysis sheet of the PTRM titled 'Repayment of debt',[964] rather than being calculated as

962 TransGrid, *Revised revenue proposal*, pp. 80–81, point (e); Transend, *Revised revenue proposal*, p. 60; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

963 TransGrid, *Revised revenue proposal*, pp. 80–81, point (e); Transend, *Revised revenue proposal*, p. 60; EnergyAustralia, *Revised regulatory proposal*, p. 48 and Integral Energy, *Revised regulatory proposal*, p. 46.

964 The repayment of debt is multiplied by minus 1 in order to express the debt component of capex as a positive number.

60 per cent of capex. The residual of capex less the increase in debt funding is the amount of capex that must be funded through retained earnings and then new equity.[965]

The effect of this adjustment in dollar terms is consistent with the amendment proposed by CEG and adopted in the revised regulatory proposals. However, it also overcomes the inconsistency of an adjustment to repay debt where the RAB is increasing and the regulatory framework assumes debt is refinanced every regulatory control period (rather than repaid). The adjustment implicitly recognises that a portion of retained earnings is attributable to debt rather than entirely equity.

Adjustment to forecast capex funding requirement

The AER identified an error in the value assumed to be the funding requirement for capex in the draft decision and in the subsequent revised regulatory proposals. The value inappropriately included an adjustment to increase expected capex by the WACC for half a year. This is done in the PTRM to provide a return on capex during the year it is incurred based on the assumed timing of the incurrence of capex. However, for financing purposes, it is only the net capex value rather than the ‘grossed–up’ capex value that is of relevance. The AER has therefore corrected this error in its benchmark equity raising cash flow analysis. This results in a lower forecast capex funding requirement.

Amortisation of allowance

In its draft decision for the NSW DNSPs, the AER expressed a preference for treating an equity raising cost allowance as part of the RAB—that is, to amortise the allowance.[966] This approach is consistent with the AER’s 2006 Powerlink transmission determination, which considered the benchmark cash flow analysis to determine the extent of equity raising cost associated with forecast capex for the first time. The AER considers that although the amortisation treatment is equivalent in net present value terms to a perpetuity income stream provided as part of the opex allowance, there are several advantages to this approach:

- it ensures a transparent link between the equity raising cost and the capex that required the equity raising
- it eases administrative implementation in future regulatory resets
- it implements the recommendation made by ACG in its 2004 report.[967]

In accordance with the AER’s previous approach, the benchmark equity raising cost allowance for the NSPs will be amortised over the weighted average standard life of the relevant RAB for the purpose of providing the equity raising cost allowance associated with forecast capex for the next regulatory control period.

965 Using the example described by CEG on page 22–23 of its January 2009 report, the RAB increases from $100 to $200 from one year to the next after taking into account depreciation of $100 and capex of $200. In its revised benchmark equity raising cash flow analysis, the AER has assumed the debt component of capex is given as the benchmark gearing ratio (60 per cent) multiplied by the increase in RAB value ($200 less $100), that is $60. The AER's previous approach assumed that the debt component of capex was 60 per cent of $200 (forecast capex).

966 AER, *NSW DNSP draft decision*, p. 197. Note that the preference was not expressed in the TransGrid, Transend, and ActewAGL draft decisions because these draft decisions did not include any such allowance.

967 ACG, 2004, p. xiii.

Summary of equity raising cost considerations

The AER has considered the arguments made by the NSPs on equity raising costs associated with forecast capex, including consultant reports and submissions.

The AER considers that there is no basis on which to accept the proposed allowance for indirect equity raising costs. The AER notes that personal transaction costs are not an appropriate justification for an allowance under the regulatory framework. Similarly, the AER notes that arguments relying on wealth transfer between investors are not appropriate justification for an allowance, since the regulatory framework specifies investor return in aggregate.

The AER rejects the argument that the benchmark firm would exclusively use placements to issue equity, finding that placements are not the majority market practice. Additionally, the AER considers that the characteristics of the benchmark firm may vary substantially from the market average, such that it would not be bound by majority market practice in any case.

The AER considers that the best estimate of the direct costs of equity raising is 2.75 per cent, the benchmark unit rate calculated in accordance with the ACG methodology and applied in the draft decision. The AER rejects the alternative estimates of direct equity raising costs proposed by the NSPs on the grounds that they deviate substantially from the equity raising conditions relevant to the benchmark firm.

The AER considers that there is a need to adjust the benchmark cash flow analysis to ensure that the gearing ratio is maintained, by linking the debt contribution to capex to the change in RAB each year. Further, the AER has set the dividend level to ensure that the dividends distribute the value of imputation credits assumed in the PTRM (which is based on the assumed gamma value prescribed under the NER). The AER also notes the prevalence of DRPs as a method for raising equity, and adjusts the benchmark cash flow analysis to allow 30 per cent of dividends to be reinvested via DRP at a benchmark cost of 1 per cent of the amount reinvested.

The AER considers that there is no evidence on which to provide an allowance for the proposed costs of using retained earnings as a source of equity.

For each NSP, the AER will apply the amended benchmark cash flow analysis and determine the amount that will be reinvested via DRP over the next regulatory control period. The allowance for the DRP cost will be 1 per cent of the amount reinvested in this way. The AER will then determine the amount of external equity required for the next regulatory control period in excess of that provided by the DRP. The allowance for external equity raising cost will be 2.75 per cent of the amount raised in this way. The two allowances will then be added to the RAB, and amortised over the weighted average standard life of the RAB.

Appendix F: Definition of system minute

Parameter 2 Loss of supply event frequency

Definition/formula	number of events greater than 0.05 system minutes per annum
	number of events greater than 0.25 system minutes per annum
	system minutes are calculated for each supply interruption by the 'load integration method' using the following formula:
	$$\text{system minutes} = \frac{\Sigma\ (\text{MWh unsupplied} \times 60)}{\text{MW peak demand}}$$
	where:
	MWh unsupplied is the energy not supplied as determined by using NEM metering and substation load data. This data is used to estimate the profile of the load over the period of the interruption by reference to historical load data
	MW peak demand means the maximum amount of aggregated electricity demand recorded at entry points to the TransGrid transmission network and interconnector connection points during the reporting period in which the event occurs
	period of the interruption starts when a loss of supply occurs and ends when TransGrid offers supply restoration to the customer
	the performance parameter applies to exit points only
	an interruption >0.25 system minutes also registers as a >0.05system minutes event

Appendix G: Performance incentive curves

The following tables and figures represent the scale of the financial penalty or reward (y–axis) resulting from TransGrid's performance (x–axis) against each of its parameters. Tables G.1 to G.6 show the set of linear equations represented in figures G.1 to G.6.

In accordance with the service target performance incentive scheme the s–factor result for each calendar year should be determined by the following formula:

S_{ct} = S1 + S2 + S3 + S4 + S5 +S6

where:

S_{ct} = the total service standards factor (s–factor)

ct = the time period/calendar year

S1 = s–factor for transmission line availability

S2 = s–factor for transformer availability

S3 = s–factor for reactive plant availability

S4 = s–factor for loss of supply event frequency > 0.05 system minutes

S5 = s–factor for loss of supply event frequency > 0.25 system minutes

S6 = s–factor for average outage duration

Figure G.1: Transmission line availability

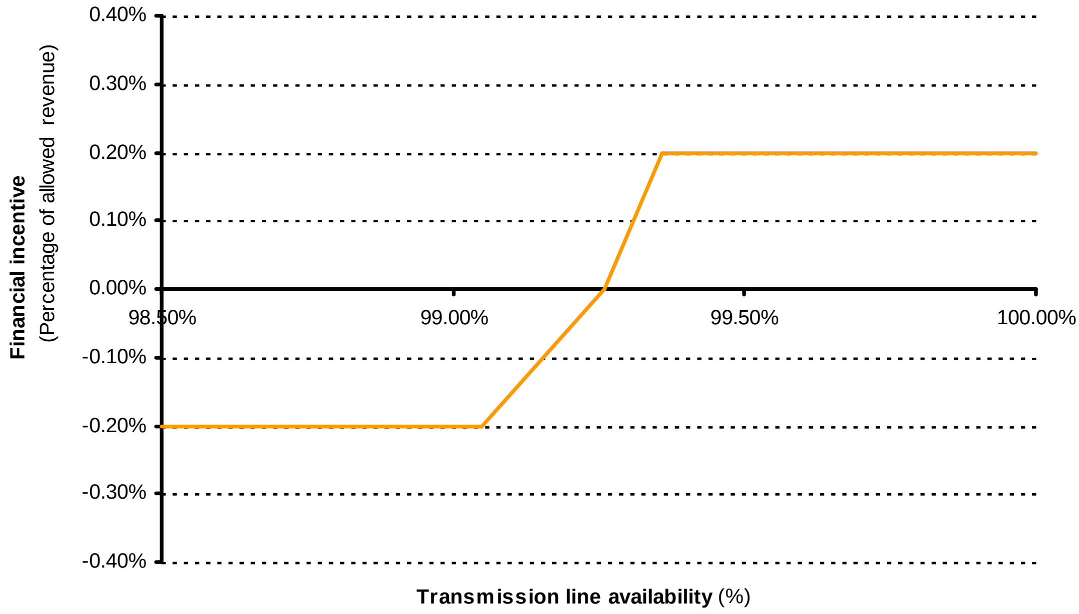


Table G.1: Transmission line availability

							Where:				
S1	=	–0.002000							Availability	<	99.05%
S1	=	0.952381	x	Availability	+	–0.945333	99.05%	≤	Availability	≤	99.26%
S1	=	2.000000	x	Availability	+	–1.985200	99.26%	≤	Availability	≤	99.36%
S1	=	0.002000					99.36%	<	Availability		

Figure G.2: Transformer availability

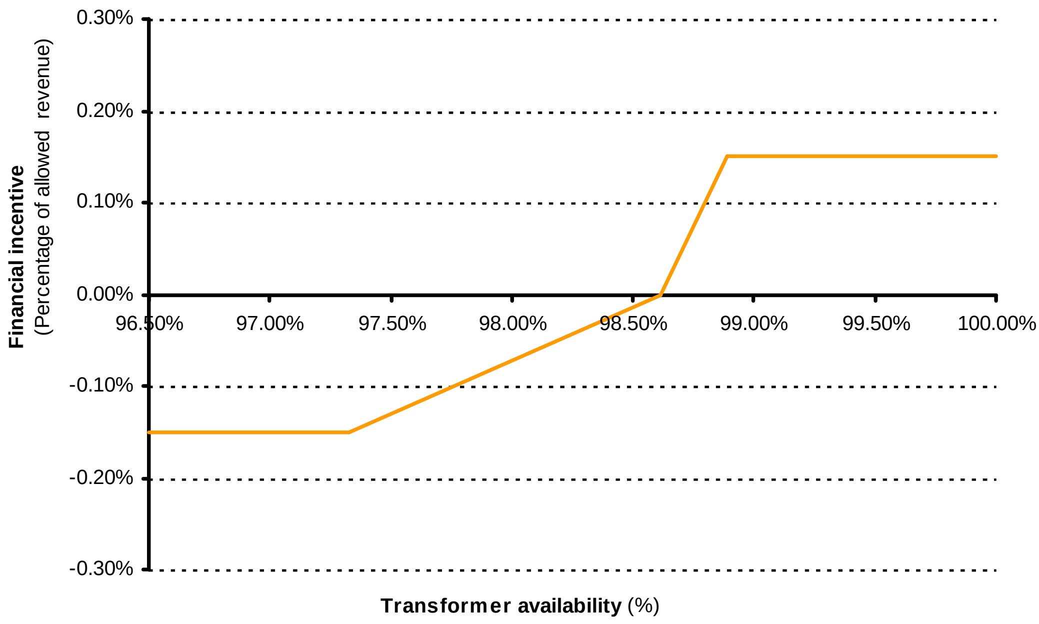


Table G.2: Transformer availability

							Where:				
S2	=	–0.001500							Availability	<	97.33%
S2	=	0.117188	x	Availability	+	–0.115559	97.33%	≤	Availability	≤	98.61%
S2	=	0.535714	x	Availability	+	–0.528268	98.61%	≤	Availability	≤	98.89%
S2	=	0.001500					98.89%	<	Availability		

Figure G.3: Reactive plant availability

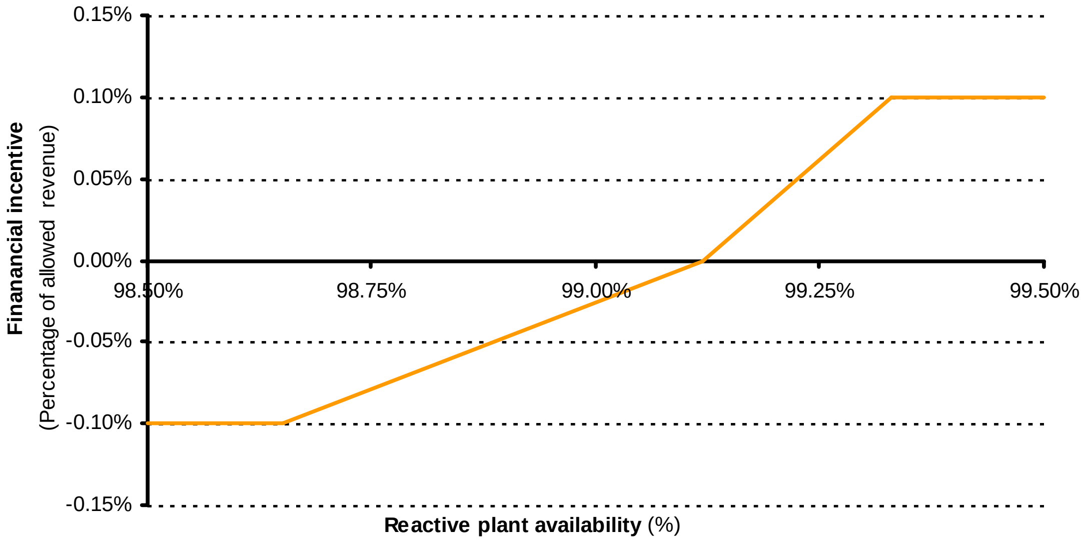


Table G.3: Reactive plant availability

							Where:				
S3	=	–0.001000							Availability	<	98.65%
S3	=	0.212766	x	Availability	+	–0.210894	98.65%	≤	Availability	≤	99.12%
S3	=	0.476190	x	Availability	+	–0.472000	99.12%	≤	Availability	≤	99.33%
S3	=	0.001000					99.33%	<	Availability		

Figure G.4: Loss of supply event frequency > 0.05 system minutes

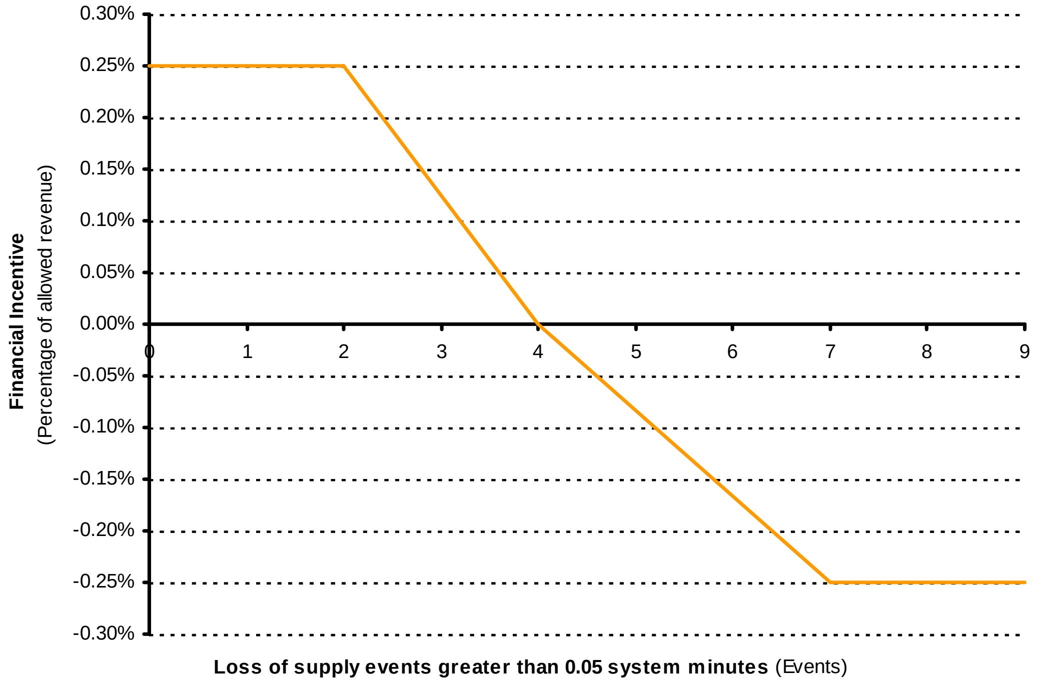


Table G.4: Loss of supply event frequency > 0.05 system minutes

							Where:				
S4	=	–0.002500					7	<	No. of events		
S4	=	–0.000833	x	No. of events	+	0.003333	4	≤	No. of events	≤	7
S4	=	–0.001250	x	No. of events	+	0.005000	2	≤	No. of events	≤	4
S4	=	0.002500							No. of events	<	2

Figure G.5: Loss of supply event frequency > 0.25 system minutes

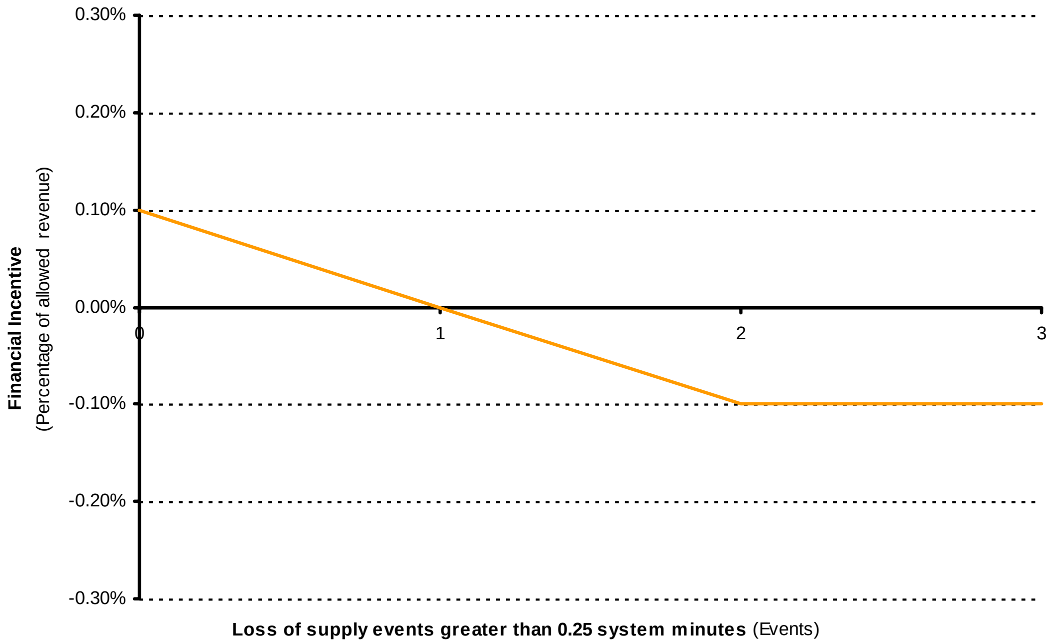


Table G.5: Loss of supply event frequency > 0.25 system minutes

							Where:				
S5	=	–0.001000					2	<	No. of events		
S5	=	–0.001000	x	No. of events	+	0.001000	1	≤	No. of events	≤	2
S5	=	–0.001000	x	No. of events	+	0.001000	0	≤	No. of events	≤	1
S5	=	0.001000							No. of events	<	0

Figure G.6: Average outage duration

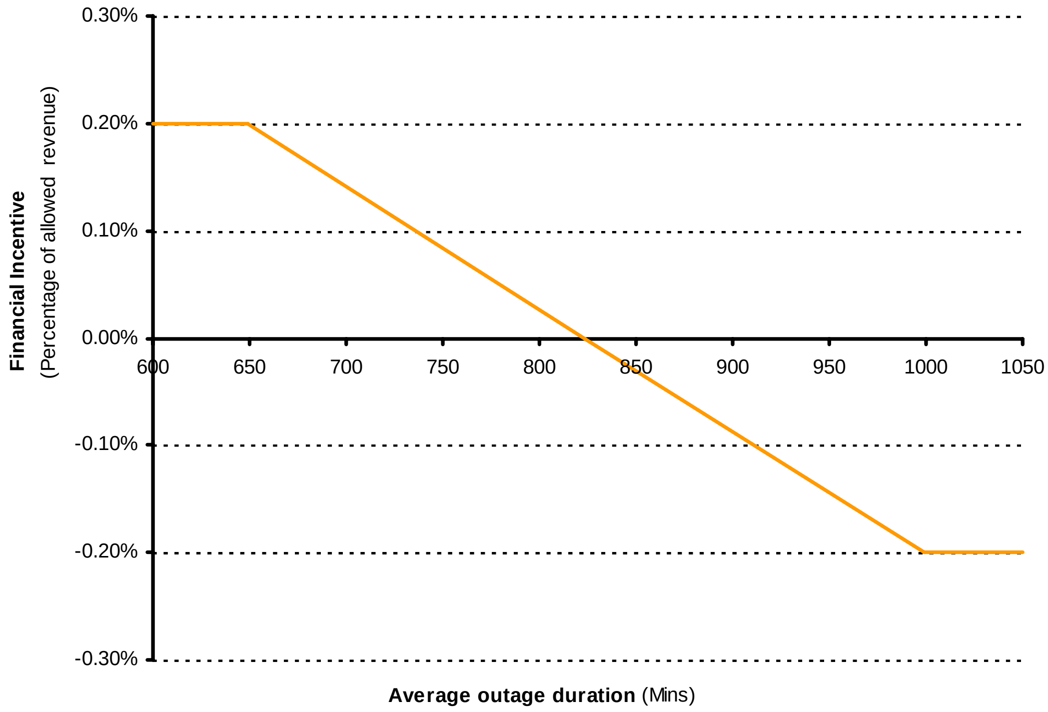


Table G.6: Average outage duration

							Where:				
S6	=	–0.002000							Average outage duration	>	999
S6	=	–0.000011	x	Average outage duration	+	0.009417	824	≤	Average outage duration	≤	999
S6	=	–0.000011	x	Average outage duration	+	0.009417	649	≤	Average outage duration	≤	824
S6	=	0.002000							Average outage duration	<	649

Appendix H: New information and late submissions received by the AER

In accordance with clause 6A.12.3 of the NER, the AER invited TransGrid to submit a revised revenue proposal by 16 January 2009. Clause 6A.12.3(b) of the NER provides that a TNSP may only make revisions in its revised revenue proposal so as to incorporate the substance of any changes required to address matters raised by the draft determination or the AER's reasons for it.

Despite the requirement that revised revenue proposals respond only to the draft decision, several new matters were raised and new information was provided that did not directly address matters raised by the draft decision or the AER's reasons for it.

The AER decided to invite submissions on the revised revenue proposal. In view of the tight timeframe within which to consider any submissions, the AER stated that submissions must be received by 16 February 2009.

Despite the close of submissions on 16 February 2009, the AER received several submissions after that date.

The AER sets submission deadlines to ensure that there is adequate time to consider the submissions it receives and take them into account in its decision making process. Section 28ZC of the NEL and clause 6A.16(a) of the NER expressly provide that the AER may, but need not, consider a submission it receives after the time for making the submission has expired.

The AER has dealt with new information and late submissions on a case–by–case basis in deciding whether or not, or to what extent, it was able to consider the new information or late submission. In deciding whether to consider the new information or late submission, the AER has taken into account the nature of the material, whether it sought to provide new information, and the circumstances surrounding its submission.

Much of the new information and late submissions related to the impacts of the global financial crisis. This crisis has been described by the International Monetary Fund as the deepest shock to the global financial system since the great depression. Given this extraordinary change in circumstances within the economic environment, the AER has decided to consider new information and late submissions that related to the impacts of the global financial crisis. Those submissions, or parts thereof, relating to matters other than the global financial crisis have been dealt with on a case–by–case basis.

The AER's consideration of late submissions is detailed in table H.1.

Table H.1: Late submissions received by the AER

Date	Submitted by	Topic	AER consideration
19 February 2009	Newcrest	Response to draft decision – contingent projects	Fully considered
20 February 2009	EUAA	Comments on draft decision and revised revenue proposal – capex, opex, cost of capital and service standards	Fully considered
10 March 2009	TransGrid	Response to issues raised by EUAA	Fully considered
20 March 2009	TransGrid	Expert opinion on debt and equity raising costs by SFG Consulting	Fully considered
25 March 2009	TransGrid	CEG memo – rate of return and averaging period, and report by Professor Officer – risk–free rate averaging period	Fully considered
3 April 2009	TransGrid	CEG memo of evidence – equity raising costs and debt risk premium	Limited consideration, due to limited time available