Synergy's Costs and Electricity Tariffs

Final Report

4 July 2012

Economic Regulation Authority
WESTERN AUSTRALIA

Important Notice

A full copy of this document is available from the Economic Regulation Authority website at www.erawa.com.au.

For further information, contact:

Economic Regulation Authority
Perth, Western Australia
Phone: (08) 9213 1900

Contents

Executive Summary **8**
Introduction 8
Background 8
How are Efficient Cost Reflective Electricity Tariffs Calculated? 9
Findings 11
Wholesale Electricity Cost 13
Retail Operating Costs 16
Non-Controllable Costs 17
Retail Margin 17
Cost Reflective Electricity Tariffs 18
Impact on Synergy and Government 21
Future Regulatory Arrangements 22
Recommendations and Findings **23**
Overall Findings 23
Specific Findings 23
1 Introduction **25**
1.1 Terms of Reference 25
1.2 Background to the Inquiry 26
1.3 Review Process 27
2 Inquiry Approach **29**
2.1 Aim of the Inquiry 29
2.2 Current Process for Setting Tariffs 29
2.2.2 Economic Efficiency 30
2.2.3 Estimation of Synergy's Efficient Costs 32
2.2.4 Allocating Costs to Customer Classes 34
2.2.5 Tariffs 35
2.2.6 Gap Analysis 35
3 Wholesale Electricity Procurement Costs **36**
3.1 Background 36
3.2 Draft Report 36
3.3 Public Submissions 37
3.3.1 Wholesale Energy Procurement 37
3.3.2 Renewable Energy Certificates 38
3.3.3 Carbon Costs 38
3.4 Use of the LRMC Approach to Determining Efficient Tariffs 39
3.4.1 Applicability of LRMC in Efficient Cost Determination 40
3.4.2 Other issues relating to LRMC 41
3.5 Synergy's Demand Forecasts 44
3.5.1 The use of Synergy's total load 44
3.5.2 Synergy's Approach to Demand Forecasting 45
3.5.3 Authority Assessment of Synergy's Demand Forecasts 46

3.6 Wholesale electricity costs 47
3.6.1 Synergy's procurement of wholesale electricity 47
3.6.2 LRMC of Wholesale Electricity 54
3.6.3 Costs of Carbon Pricing 57
3.6.4 Procurement of RECs and LGCs 59
3.7 Final Recommendations 61
4 Retail Operating Costs 63
4.1 Background 63
4.2 Draft Report 63
4.3 Public Submissions 64
4.4 Service Standards 65
4.5 Synergy's Estimates of its Retail Operating Costs 65
4.6 Synergy's Capital Expenditure 67
4.7 Consultant Assessment 68
4.7.1 Consultant's Approach 68
4.7.2 Consultant Findings 69
4.8 Authority Assessment 70
4.8.1 Benchmarking retail operating costs 70
4.8.2 Differentiating retail operating costs 72
4.8.3 Customer acquisition and retention costs 73
4.8.4 Escalation of the retail operating cost allowance 73
4.8.5 Depreciation 74
4.9 Findings 75
5 Non-Controllable Costs 76
5.1 Draft Report 76
5.2 Public Submissions 76
5.3 Network Charges 77
5.3.1 Background 77
5.3.2 Authority's Assessment 77
5.4 Ancillary Services Costs 79
5.4.1 Background 79
5.4.2 Authority Assessment 79
5.5 Market Fees 80
5.5.1 Background 80
5.5.2 Authority's Assessment 80
5.6 Balancing Costs 81
5.7 Adjustment mechanism for non-controllable costs 82
5.7.1 Background 82
5.7.2 Authority Assessment 82
5.8 Findings 84
6 Retail Margin 85
6.1 Background 85
6.2 Draft Report 85

6.3 Public Submissions 85
6.4 Benchmarking Approach 86
6.5 Bottom-Up Approach 87
6.5.1 Rate of return 88
6.5.2 Asset Valuation 89
6.6 Authority's Assessment 93
6.7 Findings 94
7 Electricity Tariffs 95
7.1 Background 95
7.2 Draft Report 95
7.3 Public Submissions 95
7.4 Cost Reflective Tariffs 96
7.4.1 Background 96
7.4.2 Allocation of Costs Across Customer Groups 97
7.4.3 Cost Reflective Tariffs 100
7.5 Amalgamation of Tariffs 103
7.5.1 Background 103
7.5.2 Authority Assessment 105
7.6 Findings 106
8 Tariff Impacts 107
8.1 Draft Report 107
8.2 Public Submissions 107
8.3 Principles 108
8.4 Impacts on Customers 109
8.4.1 Residential Customers 109
8.5 Impacts on Synergy and Government 111
8.5.1 Background 111
8.5.2 Synergy's Revenue Requirement 111
8.5.3 Impacts on Government 113
8.6 Findings 116
9 Regulation of Tariffs 117
9.1 Background 117
9.2 Draft Report 117
9.3 Public Submissions 117
9.4 Removal of Regulated Tariffs for Contestable Customers 119
9.4.1 Background 119
9.4.2 Authority Assessment 120
9.5 Regulatory Arrangements 123
9.5.1 Principles for the Regulatory Framework for Retail Prices 123
9.5.2 Authority Assessment 124
9.5.3 Findings 125
Appendices 126
Appendix A. Terms of Reference 127

Appendix B. Background to the Electricity Sector in Western Australia **128**
Appendix C. Synergy's Current Tariffs **151**
Appendix D. Synergy's Demand Forecasts **155**
Appendix E. Synergy's Rate of Return **156**
Appendix F. Synergy's Concessions and Rebates **174**
Appendix G. Glossary **175**

List of Tables

Table 1 Tariffs With All Components Being Cost Reflective (c/kWh, nominal) TEC Exclusive 2012/13 to 2015/16 19

Table 2 Individual Tariffs; TEC Inclusive but Otherwise Cost Reflective (c/kwh, nominal) 2012/13 to 2015/16 20

Table 3 Tariff Percentage Increases 2009/10 to 2014/15 26

Table 4 Synergy's Forecast Variations as Percentage of Total Electricity Volumes 2005/06 to 2010/11 46

Table 5 Authority's Estimates of Synergy's Wholesale Electricity Costs 2012/13 to 2015/16 53

Table 6 Adjusted LRMC Accounting for Additional Capacity Required by the IMO 2012/13 to 2015/16 57

Table 7 Carbon Impact on LRMC and Contract Dispatch Prices 2012/13 to 2015/16, Nominal 58

Table 8 Synergy's Forecast LREC Expenses ($/LGC) 60

Table 9 Efficient Wholesale Electricity Cost ($/MWh, nominal) 2012/13 to 2015/16 61

Table 10 Synergy's Actual and Forecast Operating Costs ($m) 2010/11 to 2015/16 66

Table 11 Synergy's Estimated Retail Costs for Contestable Customers in 2010/11 and 2012/13 67

Table 12 AGL and Origin Energy's average depreciation per customer 75

Table 13 TEC Attributable to Synergy's Tariff Customers and Total TEC ($m, nominal) 2012/13 to 2015/16 78

Table 14 Synergy's Tariff Volume, Network Charges and Costs 2012/13 to 2015/16 78

Table 15 Actual and Forecast Ancillary Services Costs Paid by Synergy ($m) 2009/10 to 2015/16 79

Table 16 Synergy's Actual and Forecast Market Fees ($m) 2009/10 to 2015/16 81

Table 17 Synergy's Net Forecast Balancing Costs ($m) 2012/13 to 2015/16 82

Table 18 Retail Margin Expressed as EBITDA per cent of Total Costs Adopted by Australian Regulators in the National Electricity Market 87

Table 19 Cost of Acquiring a Business, Total Asset Base ($ million) 2012/13 to 2015/16 90

Table 20 Estimated Regulatory Asset Base and Associated Retail Margin ($ million) 2011/12 to 2015/16 90

Table 21 Regulatory Customer Acquisition and Retention Cost Estimates 91

Table 22 Estimated Value of Synergy's Regulated Asset Base (Tangible Asset Values in $m 2011/12 dollars) 2012/13 to 2015/16 92

Table 23 Estimated Regulatory Asset Base and Associated Retail Margin ($m 2011/12 dollars) 2012/13 to 2015/16 93

Table 24 Cost Reflective Tariff Breakdown, Total Tariffs (c/kWh, nominal) TEC Excluded 2012/13 to 2015/16 96

Table 25 TEC Inclusive Tariff Breakdown (all other components being cost reflective) Total Tariffs (c/kWh, nominal) 2012/13 to 2015/16 97

Table 26 ERA's Capacity Allocation for Synergy's Contracted Capacity in 2012/13 99

Table 27 Cost Reflective Tariffs, Individual Tariffs (c/kWh, nominal) TEC Exclusive 2012/13 to 2015/16 101

Table 28 Assumed Budgeted Tariffs versus Cost Reflective Tariffs (c/kWh) TEC Exclusive 2012/13 102

Table 29 Bill Impacts: Estimated Average Annual Bill for a Residential Customer, TEC Exclusive 2011/12 to 2015/16 110

Table 30 Synergy's Total Electricity Efficient Revenue Requirement ($m, nominal) TEC Exclusive 2011/12 to 2015/16 111

Table 31 Synergy's Total Electricity Revenue Requirement Based on Actual Projected Costs ($m, nominal) TEC Exclusive 2011/12 to 2015/16 112

Table 32 Differences Between Synergy's Efficient Revenue Requirement and Actual Revenue Requirement ($m, nominal) TEC Exclusive 2011/12 to 2015/16 112

Table 33 Financial Impacts on Synergy and Government ($m) 2012/13 - 2015/16 115

Table 34 Average Consumption in 2010/11 for L3 and R3 Customers 120

Table 35 Average Consumption in 2010/11 for M1, S1 and T1 Customers 120

Table 36 Regulated Tariff Groupings 141

Table 37 Contestable Tariff Glide Path (Annual Percentage Increases) to the Cost Reflective Tariff Levels Calculated by the OoE in 2009 2011/12 to 2014/15 143

Table 38 Subsidies Received by Synergy ($m nominal) 2010/11 to 2014/15 145

Table 39 Synergy's Current Tariffs 151

Table 50 Estimates of Australian Market Risk Premium, 1969 - 2011 161

Table 51 A Benchmark Sample of Australian Corporate Bonds with Credit Rating of BBB band as at 30 April 2012. 167

Table 52 Observed Yields, Adjusted Nominal Risk Free Rate, the Debt Risk Premium for BBB Band Australian Corporate Bond as at 30 April 2012. 167

Table 53 Debt Risk Premiums under Various Scenarios and Weighted Average Approach as at 30 April 2012, Per cent 168

Table 54 A Determination of a Rate of Return as at 30 April 2012 172

Table 55 Authority's estimates of WACC for Synergy 173

Table 56 Synergy's Customer Concessions 2011/12 174

List of Figures

Figure 1 Gap between Current Tariffs and Cost Reflective Tariffs in 2012/13 Averaged across all Customers 11

Figure 2 Gap between Current Tariffs and Cost Reflective Tariffs in 2012/13 for Residential Customers (A1 Tariff) 12

Figure 3 Index of Real Residential Electricity Prices in Australian Capital Cities 27

Figure 4 Authority's Approach to Determination of Cost Reflective Electricity Retail Tariffs 30

Figure 5 Synergy's Historical and Forecast Energy Sales (GWh) 2006/07 to 2015/16 45

Figure 6 Synergy's Total Cumulative Budgeted and Actual Expenditure for its Total Asset Investment Programme ($'000s) 2006/07 to 2014/15 68

Figure 7 One Month Annualised Customer Churn Rates 122

Figure 8 Synergy's Actual and Budgeted Income (Electricity Only) ($m, nominal) 2006/07 to 2011/12 140

Figure 12 Australia's Market Risk Premium 1969 - 2011 (%) 161

Executive Summary

Introduction

The Economic Regulation Authority (**Authority**) has conducted an inquiry into:

- the efficiency of the costs incurred by Synergy, the Government-owned electricity retailer in the South West of Western Australia; and

- the efficient level of retail tariffs that electricity consumers in the South West of Western Australia would need to pay if retail tariffs were no longer subsidised by taxpayers.

Synergy purchases electricity and sells it to around one million industrial, commercial and residential customers in the South West. Its annual revenue is approximately $2.7 billion each year.[1]

The Authority is an independent Statutory Authority, established by the Parliament of Western Australia. The Authority's purpose is to ensure consumers in Western Australia receive quality services for a reasonable price. The Authority performs a range of regulatory functions that are intended to achieve this purpose.

The Authority does not set retail electricity tariffs; these are set by the Government for non-contestable customers, and for contestable customers who opt to remain on regulated tariffs. However, the Authority can be called on by the Government to conduct independent inquiries on important economic issues. The inquiries result in recommendations to the Government and a report that must be tabled in Parliament.

The Treasurer issued this inquiry to the Authority on 11 July 2011. Specifically, the Treasurer asked the Authority to determine efficient cost reflective electricity tariffs for Synergy for the four years from 2012/13 to 2015/16. This report presents the Authority's findings and recommendations. It is the Final Report, following public consultation on an Issues Paper that was published on 11 August 2011, and on a Draft Report that was published on 4 April 2012. It incorporates analysis by consultants, who were employed by the Authority to provide technical advice, as well as analysis undertaken by the Authority.

Background

Residential electricity tariffs in Western Australia are set by the Government. For ten years, between 1997 and 2007, the State Government in Western Australia had the policy of keeping tariffs unchanged. As a result, tariffs did not even keep pace with inflation, which increased by around 47 per cent during this period.

Since 2008, electricity prices have increased by 57 per cent for residential customers. The additional ten per cent increase over and above inflation addresses, in part, other cost pressures such as:

[1] Synergy (2011), Annual Report, p9.

- higher costs of gas and coal, which are used as fuels for electricity generation;
- increases in the costs of operating Western Power's network, following a period of substantial underinvestment in that network;
- significant increases in the subsidy to Horizon Power, the electricity provider in the regional and remote parts of Western Australia. This subsidy is paid for by users of Western Power's distribution network and is the result of the State Government's policy of having uniform electricity tariffs across Western Australia for households and small businesses; and
- increases in the costs of complying with the Commonwealth and State Government's renewable energy policies.

Even after the 57 per cent increase, the current residential tariff in Western Australia is still low compared to equivalent tariffs in other jurisdictions.[2]

How are Efficient Cost Reflective Electricity Tariffs Calculated?

'Cost reflective' tariffs are tariffs that are just sufficient to cover efficient input costs, and at the same time provide for a reasonable return to the retailer.

Given the increase in electricity tariffs in recent years, the question that the Authority has been tasked to answer is: how much more of an increase is required to achieve efficient cost reflective tariffs? In considering this question, therefore, the Authority has evaluated the following components contributing to the cost of electricity:

- the cost of generating electricity (which accounts for around 46 per cent of total costs);
- the cost of transmitting electricity across the transmission and distribution network (up to 33 per cent of total costs);
- the cost to retailers of meeting their renewable energy obligations and the cost associated with the newly introduced carbon pricing regime (around 11 per cent of total costs);
- the billing, call centre and other costs associated with running a retail electricity business (7 per cent of total costs); and
- the return that the electricity retailer must earn to have an incentive to provide a service (around 3 per cent of total costs).

[2] The Authority is aware of concerns that separation of Verve Energy and Synergy may have contributed to the recent price increases. However, the Authority considers that the 57 per cent increase in electricity tariffs in recent years was inevitable, regardless of how the disaggregation of the old Western Power was structured (that is, regardless of whether Verve Energy and Synergy remained as a single Government trading entity).

The Authority has analysed each of these costs separately. In doing so, the Authority has been guided by an important principle: consumers should only pay the costs that would be incurred if the market for electricity were effectively competitive and efficient. This is clearly not yet the case in Western Australia. Synergy, the dominant retailer, accounted for more than 70 per cent of the retail market in 2010/11 (only large electricity users can choose their retailer), while Verve Energy, the dominant generator, will account for more than 50 per cent of certified generation capacity in 2013.

In a competitive market, customers who are not satisfied with a retailer's price or level of service have the choice to switch to another service provider (as occurs, for example, in the mobile telephone sector). However, due to legislative restrictions, switching is not currently an option for households and small business electricity consumers in the South West. Instead, consumers depend on the Authority and the Government to put pressure on service providers to be efficient, whilst also maintaining an appropriate level of service.

Whilst regulation is not as effective as competition at serving the long term interests of consumers, regulators can attempt to identify the costs that would be incurred if the market were competitive. This is the position that the Authority has taken in this inquiry. The electricity providers, or their owners, are not entitled to earn more than they would in a competitive market. They should not be rewarded for being inefficient due to a lack of competition.

The test for whether existing tariffs are efficient and cost reflective is whether an efficient new retailer could come into the market and sell electricity at a lesser tariff than what the existing retailer is charging. In undertaking its analysis, the Authority has kept this test in mind.

Finally, the Authority notes that the Government's policy to keep tariffs at the same level for each customer category, regardless of their location, means that regional customers pay the same tariff as those in the South West of Western Australia, even though it costs more to service them. This subsidy is currently paid by the South West customers, through distribution network charges, under the Tariff Equalisation Contribution (**TEC**) scheme.[3]

In determining the efficient cost reflective tariffs, the Authority considers that the TEC should not be part of these tariffs and recommends that the TEC no longer be met by electricity consumers in the South West. The subsidy to Horizon Power is not an efficient cost that is associated with generating, distributing or retailing electricity in the South West. It is a levy that is imposed on electricity customers in the South West, on the basis of a government policy decision. Just as the subsidy for Water Corporation's regional customers is not paid for by Perth customers, neither should the subsidy for regional electricity consumers be paid for by Synergy's customers. The subsidy should be provided by a Community Service Obligation (**CSO**), which is funded out of general taxation revenue, as is the case with water customers. The TEC currently accounts for approximately $83 (or around 6 per cent) of a residential consumer's annual electricity bill in 2011/12, and is expected to rise in 2012/13. Accordingly, the analysis and the results provided in this report are set out on both a TEC-inclusive and TEC-exclusive basis.

[3] TEC is explained in more detail in Section 5.3.1 of this Report. It should also be noted that there are other subsidies that the Government provides for financial assistance to help customers with financial difficulties.

The Terms of Reference require the Authority to determine cost reflective retail tariffs. In doing so, the Authority has examined costs for Synergy's overall retail customer base including regulated and contestable customers. While the Authority has recommended efficient cost reflective tariffs for regulated customers, non-regulated customers were also examined, but only to the extent of their impact on cost allocation and overall financial impact of Synergy. However, the Authority has maintained that non-regulated customers remain unregulated and recommends extending price deregulation to the remaining very large contestable customers (broadly, those who use more than 160 MWh per annum) who are still on regulated tariffs.

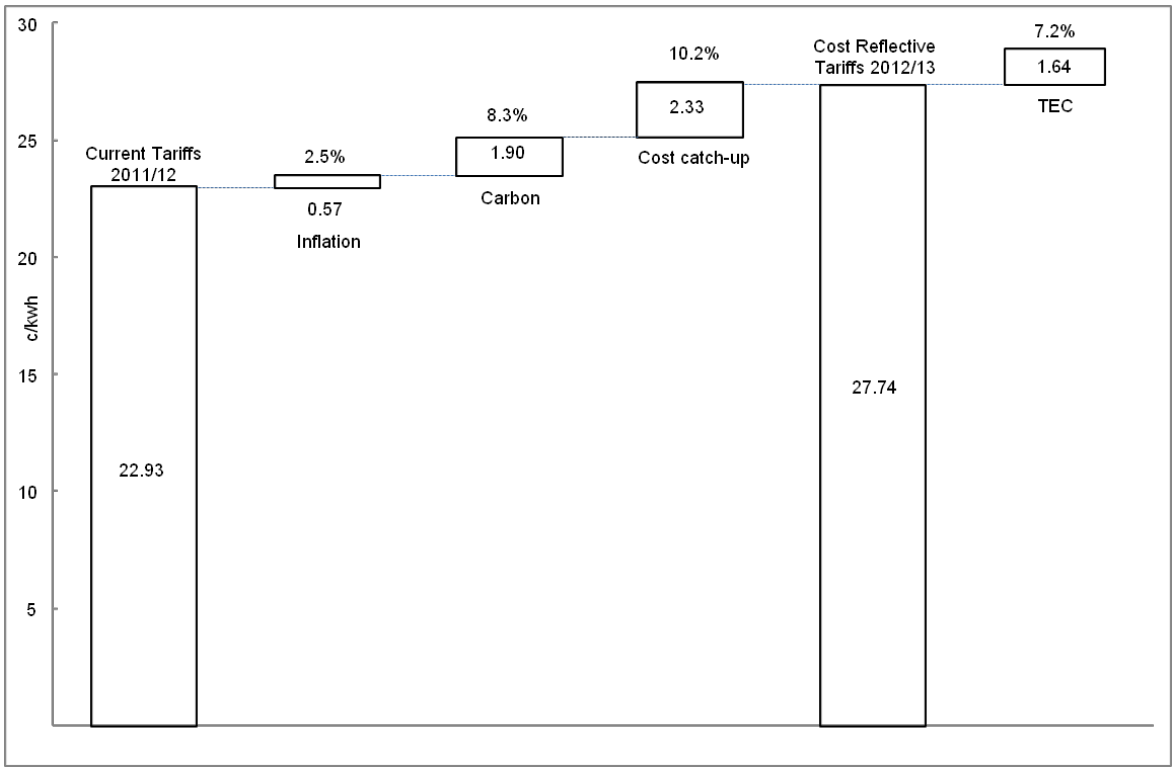
Findings

Cost Reflective Tariffs

The Authority has estimated that Synergy's overall revenue from regulated customers, on average, would have to increase by approximately 21 per cent to achieve efficient cost reflectivity, after allowing for the additional cost associated with the carbon pricing regime that will take effect from 1 July this year.

Figure 1 illustrates the movement from current tariffs to cost reflective tariffs, averaged across all customer categories (shown in c/kwh).

Figure 1 Gap between Current Tariffs and Cost Reflective Tariffs in 2012/13 Averaged across all Customers



Source – ERA Analysis

Across all customer categories, on average, Synergy will recover an estimated 22.93 c/kwh in 2011/12. In 2012/13, an adjustment for inflation will increase this average price by 0.57 c/kwh (or 2.5 per cent).

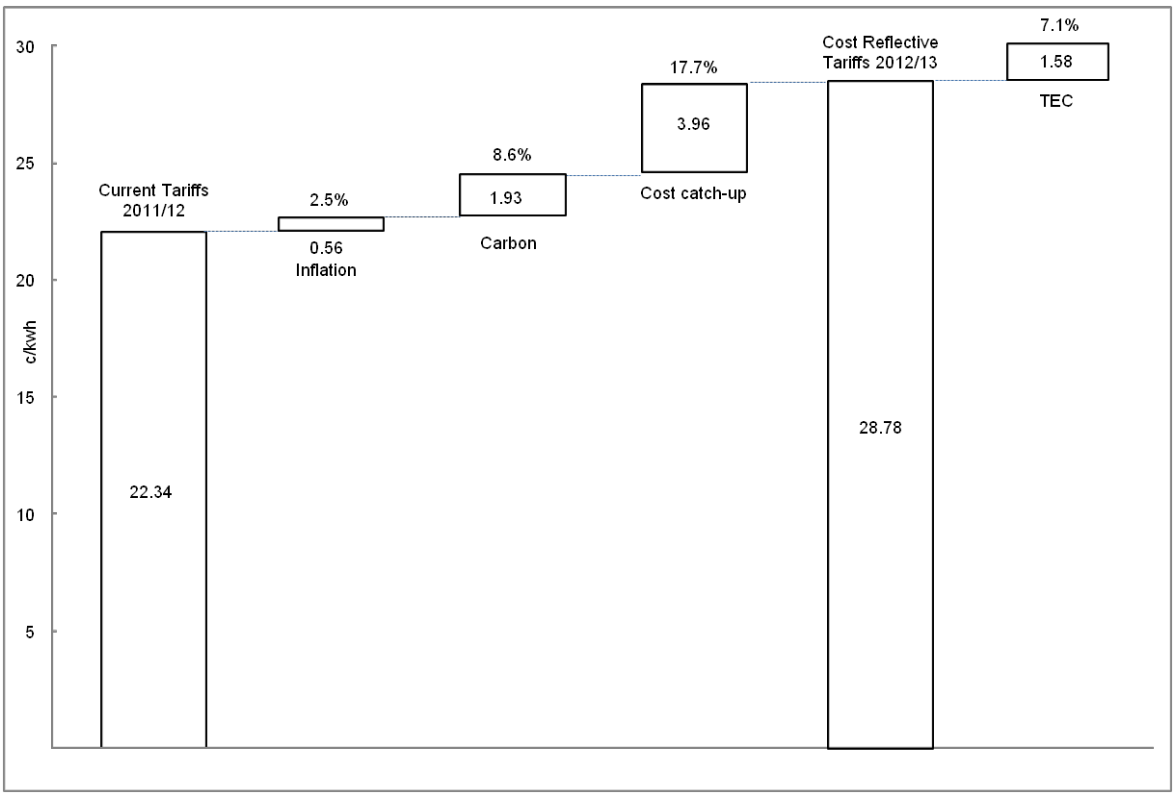
The new carbon pricing regime, introduced by the Federal Government, will increase the average price by an estimated 1.90 c/kwh (or 8.3 per cent).

In order to catch-up on other cost increases faced by Synergy, and to bring the tariffs to cost reflectivity in 2012/13, a further increase of 2.33 c/kwh (or 10.2% per cent) will also be needed.

The increase for each customer category will depend on the gap that exists between the current tariff and the efficient cost reflective tariff. The required increase for residential customers, for example, is 29 per cent because the gap between current tariffs and cost reflective tariffs is greater for these customers.

Figure 2 illustrates the movement from current tariffs to cost reflective tariffs for residential customers, based on average revenue per kwh of energy sold (c/kwh).

Figure 2 Gap between Current Tariffs and Cost Reflective Tariffs in 2012/13 for Residential Customers (A1 Tariff)



Source – ERA Analysis

Currently, residential customers pay on average 22.34 c/kwh. In 2012/13, an adjustment for inflation will increase this average price by 0.56 c/kwh (or 2.5 per cent).

The impact of the new carbon pricing regime will add a further 1.93 c/kwh (or 8.6 per cent).

Residential tariffs will need to increase by a further 3.96 c/kwh (or 17.7 per cent) to reflect other costs in order to bring the tariffs to cost reflectivity in 2012/13.

If the TEC continues to be retained, it will add a further 1.58 c/kwh (or 7.1 per cent) to the average residential tariff.

2012/13 Budget Implications for Electricity Tariffs

The Authority notes that the government has announced electricity tariffs for 2012/13 as part of the Budget papers. The Budget papers specify an increase in Synergy's tariffs equal to the government's forecast for the Perth Consumer Price Index (**CPI**) in 2012/13, for most non-contestable customers. Furthermore, the government has also indicated that full carbon costs will be passed through to customers via tariff increases.[4]

The Authority estimates that the tariff increase and full carbon pass through that has been indicated in the government's budget papers (i.e. CPI plus full carbon pass through) will result in an average tariff for residential (A1) customers of 25.37 c/kwh. The gap between the efficient cost reflective tariff and the average tariff for residential customers would be 3.41 c/kwh (or 12 per cent) in 2012/13.

However, the Authority has estimated that for the following three years (i.e. until 2015/16) the cost reflective average level of residential tariffs will rise to 30.83 c/kwh in 2015/16. The Authority's estimate is that cost reflectivity could be achieved by having residential tariffs increase by 6.7 per cent per annum for the remaining years from 2013/14 to 2015/16. A large proportion of this increase will be the result of inflation, assumed to be 2.5 per cent per annum.

The Authority has found that, to achieve cost reflectivity, the tariffs for Synergy's non-residential customers would need to increase at a lesser rate than for residential customers. For some customers, such as large regulated contestable customers, tariffs would need to decrease to match cost reflective levels.

The remainder of this Executive Summary provides more detailed information about how the cost reflective tariffs have been derived. Each of the components that make up the cost of electricity is discussed in turn. The impact on customers is provided towards the end of this summary.

Wholesale Electricity Cost

The cost of generation is referred to in this report as the wholesale electricity cost. It is made up of the cost of capacity and the cost of energy in the context of the Wholesale Electricity Market (**WEM**) in Western Australia. The capacity cost is the fixed cost of having generation capacity available when required, and the energy cost is the variable cost associated with producing electricity, which is largely related to the cost of fuel and the type of generation plant.

The Authority has calculated Synergy's wholesale cost of electricity in two ways. The first is an estimation of Synergy's procurement costs based on its existing contract portfolio. The second is to use costs based on the amount an efficient new entrant to the market would pay, referred to in this report as the Long Run Marginal Cost (**LMRC**).

[4] Refer to Budget Paper No. 3 – Economic and Fiscal Outlook http://www.treasury.wa.gov.au/cms/uploadedFiles/State_Budget/Budget_2012_13/2012-13_budgetpaper3.pdf and Media Report, West Australian, "*Power bills tipped to rise 12 per cent*", October 13, 2011.

Why Long Run Marginal Cost?

A particular challenge for the Authority in this inquiry has been the estimation of the efficient cost of wholesale electricity. In considering this problem, the Authority has applied the principle that the efficient cost of wholesale electricity is the amount that would be incurred by an efficient new retailer. This approach leads to a price that would reflect the outcome of an effectively competitive market.

A necessary condition for a new retailer to enter the market to supply a particular customer class is that its price is no more than the price set by incumbent retailers. As the cost of purchasing wholesale electricity is a key determinant in setting the price, the new retailer would need to ensure that its cost of purchasing wholesale electricity is the lower of the following two:

i. The lowest cost that existing generators are selling wholesale electricity for; or

ii. the cost of wholesale electricity from building its own generation plant.

In making its decision on the amount it is prepared to pay for wholesale electricity, the new entrant would consider the current state of technology and demand. In assessing the current generation fleet, the new entrant would not have regard to the historical costs of the generators that are currently in use. It would know that some of those existing generators used old technology and that the configuration of existing generators may not be optimal, given the current level and shape of demand. It would also know that some generators would no longer be as competitive as they once were given the introduction of the carbon price. Given that some of the existing generators are no longer competitive, the new generator would know that some of their costs would be written-off and that those generators would not expect to earn a price that exceeded the cost of an efficient new generator.

The method that is commonly used to simulate the costs that an efficient new entrant would incur in contracting for wholesale electricity is the LRMC method. The LRMC method involves disregarding the sunk costs associated with the existing generation mix, then formulating a generation mix that results in the lowest expected cost of meeting demand, given current technology, fuel prices and load shapes. The new entrant would consider this optimal generation mix when deciding on the cost that it would be prepared to incur either in entering into contracts with existing generators or in building its own generation plant. If the new entrant disregarded this information, it would put itself at risk of incurring a cost of wholesale electricity that could be undercut by a competitor.

This competitive dynamic takes place in all well functioning markets, and sometimes leads to existing market participants taking a loss where past investment has resulted in higher costs than those faced by their competitors now. Equally, they would make larger profits where past investment has led to costs that are significantly lower than current competitors' costs. The price of wholesale electricity in a well functioning market would be expected to converge on the LRMC. With this in mind, regulators in Australia have generally used the LRMC method to either set cost reflective tariffs, or a tariff range. For example, the LRMC method has been used in New South Wales by the Independent Pricing and Regulatory Tribunal (**IPART)** in its price determination for electricity retail tariffs. LRMCs have also formed the basis for the determination of efficient wholesale costs in South Australia and in Tasmania.

Importantly, the application of the LRMC method gives new entrants confidence that retail electricity tariffs that are set by either a regulator or government will be sufficient to enable them to recover the capacity and energy costs associated with their investment. The new entrants will understand that there are risks associated with technological change, unexpected demand changes and other unforeseeable events. However, they will be compensated for these risks by the rate of return that is embodied in the LRMC calculation.

If prices were not set on the basis of LRMC, and if participants in the electricity industry were permitted to recover all of the costs incurred in the past, even if with the benefit of hindsight those investments are now considered inefficient, then consumers would end up carrying the risk and paying for it in higher prices. That would not be efficient.

The Authority has found that the generation mix that results from the LRMC method is very sensitive to the carbon price and assumptions on fuel prices and the rate of return (which reduces the competitiveness of capital intensive generation plant). The Authority's assumptions for gas prices in the Draft Report resulted in a generation mix that was entirely fuelled by gas. Some submissions, particularly the submission by Synergy, were concerned that this was not realistic because of the constraints on gas availability. The Public Utilities Office (**PUO**) also expressed concern that the LRMC calculation did not recognise the importance of coal-fired generation plant for providing security of supply.

In response, the Authority has reconsidered the assumptions that it utilised in the LRMC model. The Authority accepts that a 100 per cent gas generation mix would imply a large increase in domestic gas prices in Western Australia, that is, even if the gas could be sourced. In consequence, the Authority has reconsidered its assumptions for fuel input costs in the LRMC. The Authority's revised assumptions take account of the potential pressure for higher coal and gas prices, driven by the levels of demand implied by the LRMC method. The Authority is satisfied that the revised assumptions derived for the LRMC are appropriate and are feasible within the constraints of the Western Australian energy market.

Cost based on Synergy's Contracts

Synergy's wholesale electricity costs are underpinned by its forecasts of future electricity demand. Synergy's demand forecast methodology applies a bottom-up approach, that is, the aggregation of demand forecasts for each customer category. The Authority has reviewed Synergy's demand forecasts and forecasting methodology and considers these to be appropriate.

Synergy procures its wholesale electricity mainly by entering into bilateral contracts with electricity generators, of which Verve Energy accounts for approximately half of the supply (70 per cent in 2012/13) and the rest is provided by Independent Power Producers.

The Authority has assessed Synergy's process for procuring electricity contracts and also considered whether Synergy is utilising these contracts efficiently. Synergy currently has two kinds of contracts: bilateral contracts that are competitively procured, and a Replacement Vesting Contract (**RVC**) that Synergy entered into with Verve Energy.

Over the past five years, Synergy has entered into a number of bilateral contracts using an open, competitive tender process. The Authority is satisfied that a competitive, prudent process was followed in procuring these contracts.

A bilateral contract between Verve Energy and Synergy, called the Vesting Contract, is a contract that was set by the government and first introduced in April 2006.[5] It was subsequently replaced by the RVC in 2010. The RVC contract is relevant for this review, as it is this contract that applies to the period of this inquiry.

The process that was undertaken in the establishment of the RVC was not open and competitive. The Authority doubts that the RVC has delivered an efficient outcome to Synergy.

Comparison of Synergy's Contract Costs with LRMC

The Authority has compared the estimate of wholesale electricity costs based on LRMC with the estimate based on Synergy's existing contracts for electricity supply.

The difference between the LRMC estimate and that based on Synergy's existing contracts is a result of a number of factors. The major component of this difference is due to lower costs, due to more efficient energy generation technology. Another component of the difference is attributable to the projected cost pass-through for carbon. The estimate based on Synergy's existing contracts includes relatively higher carbon intensive generators. For example, a coal fired generation plant is more carbon intensive than a gas fired plant and so will result in higher energy costs to Synergy after the carbon price is introduced in July 2012.

In comparison, the LRMC is calculated on the premise that the value of existing generation plant adjusts immediately to the carbon price. The value of more carbon intensive plant would fall by more than the value of less carbon intensive plant. This expected adjustment to the asset values has resulted in many carbon intensive generators (that face sizeable asset value losses under a carbon price) seeking and gaining compensation from the Federal Government through industry assistance built into the government's Clean Energy scheme.[6]

The Authority recommends the use of the LRMC, as the basis for estimating the efficient cost of purchasing wholesale electricity by Synergy.

Retail Operating Costs

Operating costs refer to costs associated with the day-to-day operations of the retail business, including activities such as trading, billing, and responding to customer inquiries. The operating cost per customer is mainly driven by the level of service standards that Synergy is required to provide.

Synergy's retail operating costs are small relative to the costs of energy procurement and network charges (around $120 million in 2010/11, compared to total costs of $2,500 million). Synergy's capital expenditure has been low historically but rose to around $37.5 million in 2009/10. Most of this capital expenditure was related to Synergy's implementation of a new billing system, to replace 50 legacy systems inherited upon disaggregation from the former Western Power Corporation.

---

[5] For further information on the Vesting Contract, see Publication by the Office of Energy; *Overview of the Vesting Arrangement*, September 2006.

[6] Australian Government 2011, *Securing a Clean Energy Future: The Australian Government's Climate Change Plan*, www.cleanenergyfuture.gov.au, p 75.

To estimate Synergy's efficient operating costs, the Authority engaged consultants to benchmark Synergy's costs against those of other retailers operating in competitive retail markets. The Authority considers that benchmarking using the operating costs of electricity retailers in other Australian jurisdictions is an appropriate basis on which to determine Synergy's efficient retail operating cost. Based on this analysis, the Authority estimates that Synergy's efficient retail operating costs are approximately $81 per small regulated customer in 2010/11 prices.

Non-Controllable Costs

There are several types of costs that Synergy incurs in its normal course of business operations over which Synergy has little influence. The Authority considers it appropriate for these costs to be passed through directly to customers.

The largest component of Synergy's non-controllable costs is the network charges paid to Western Power, the operator of the network. Synergy's network charges across all customers were $862.5 million in 2010/11 and are budgeted at $1.094 billion in 2011/12.[7]

Network charges are levied on the basis of units of electricity traded and are set in accordance with the Authority's decision on Western Power's revenue requirements. In estimating Synergy's network costs, the Authority has applied the network charges published in the Authority's Draft Decision of Western Power's third access arrangement for the inquiry period from 2012/13 to 2015/16. This Draft Decision by the Authority indicates that, following a period of significant network cost increases, there is likely a small reduction in network tariffs in real terms over the next five years.[8]

As a registered market customer in the WEM, Synergy is allocated a share of the ancillary services costs, being the payments for the services required to ensure system security and reliability. Synergy also pays fees to the Independent Market Operator (**IMO**) to cover the costs of the functions performed by the IMO, System Management and the Authority. These fees make up a small proportion of Synergy's total costs (less than 1 per cent).

The Authority recognises that there may be differences between forecast and actual non-controllable costs, and recommends that these be adjusted to reflect deviations from forecast in real terms at the next major review.

Retail Margin

The retail margin represents the risk-adjusted return that an electricity retailer operating in a competitive market can earn on the investment it has made in order to provide retail services. Without a retail margin the retailer would not have an incentive to provide retail services and there would be no incentive for other retailers to enter the market. The Authority recognises that the application of a retail margin is consistent with the approach taken by regulators in other Australian states.

The retail margin is expressed as a percentage that is applied to total costs. Synergy has adopted a separate retail margin for contestable and non-contestable customers. Currently Synergy applies a retail margin of 3.4 per cent to its non-contestable business and 5 per cent to its contestable business.

---

[7] Data provided by Synergy.

[8] This can be accessed from the ERA's website. The tariffs in this report, including the impact of the TEC, will be updated after the Authority's Final Access Arrangement decision.

The Authority does not consider that the retail margin should be differentiated for contestable and non-contestable customers. The retail margin should reflect the systematic risks of the industry as a whole, not the non-systematic risks associated with the mix of customers retained by a particular business. The principle applied when setting efficient regulated tariffs is to achieve the same outcome as would apply if markets were fully competitive. The Authority would not expect the retail margin to rise if the industry moved to full retail contestability. For this reason, the tariffs for both Synergy's contestable and non-contestable customers should reflect the levels of risk that would apply in a competitive market setting. Furthermore, the practice of adopting multiple retail margins would be largely inconsistent with regulatory decisions in other jurisdictions.

The equivalent of a retail margin in the case of an electricity network business is the risk adjusted regulatory rate of return. A return on assets is determined as a product of the rate of return and the regulatory asset base. Electricity retailers such as Synergy require relatively few physical assets to operate, with most of the value of the business being associated with intangible assets.

Intangible assets are non-physical assets held by a business (for example, a brand name, ownership of a copyright, or in Synergy's case a substantial list of existing customers). The Authority has estimated the value for Synergy that reflects both its physical and intangible assets, and derived the retail margin for Synergy by applying a regulatory rate of return to the value of the business.

The Authority has applied two approaches to estimating the value of Synergy's business:

- estimating the cost of acquiring a similar business; and
- estimating the cost of acquiring and retaining customers.

Based on this analysis, the Authority estimates the value of Synergy's business to be around $900 million in 2012/13.

The Authority estimates that an appropriate rate of return for Synergy is 6.66 per cent, on a real, pre-tax basis (9.17 per cent on a nominal, pre-tax basis).

Based on these assessments, the Authority's finding is that an appropriate retail margin for Synergy for the inquiry period is 3.5 per cent of Synergy's total cost.

Cost Reflective Electricity Tariffs

The Authority's estimate of Synergy's efficient cost of service has then been allocated to individual customer classes, to derive an average efficient cost of service (c/kWh) for each tariff, as identified in Table 1 below.

Table 1 Tariffs With All Components Being Cost Reflective (c/kWh, nominal) TEC Exclusive 2012/13 to 2015/16

Tariff	Tariff Description	2011/12 Actual	2012/13 Budget	2012/13 Budget + Carbon[9]	2012/13	2013/14	2014/15	2015/16
	Non-contestable							
A1	Residential	22.34	23.12	25.37	28.78	28.83	29.40	30.83
B1	Residential water heating	14.25	14.74	17.00	18.77	18.81	19.26	20.21
C1	Non-profit organisations	22.26	22.77	25.02	25.47	25.54	25.80	27.01
D1	Charitable residential	18.79	17.91	20.16	24.87	25.14	25.37	26.05
K1	Mixed commercial & residential	23.75	24.58	26.83	27.54	27.61	28.07	29.29
L1	Low voltage supply (<50 MWh)	24.02	24.86	27.11	27.95	28.00	28.45	29.71
R1	Time-of-use tariff (<50 MWh)	17.37	17.97	20.23	30.12	30.23	30.63	32.03
W1	Traffic lights	22.91	25.66	30.18	24.56	24.73	25.05	26.62
Z1	Street lights	36.50	34.68	35.12	38.54	38.92	39.76	41.19
UMS	Unmetered supply	22.91	24.06	30.18	20.01	20.05	20.35	21.45
	Contestable							
L3	Low voltage supply (>50 MWh)	29.04	30.90	31.74	26.84	26.92	27.41	28.61
M1	General supply (high voltage)	25.21	26.02	29.64	26.39	27.65	28.21	28.99
R3	Time-of-use tariff (>50 MWh)	23.25	24.53	26.04	21.91	21.87	22.25	23.42
S1	Low/med voltage time-of-use	19.33	21.26	23.94	21.93	21.83	22.14	23.27
T1	High voltage time-of-use	18.56	20.79	22.86	20.61	20.53	20.81	21.88
	Average across all tariffs	**22.93**	**23.77**	**25.89**	**27.74**	**27.78**	**28.32**	**29.74**

Source: ERA Analysis

As shown in the table above, the move to cost reflective tariffs requires an average overall increase from Synergy's current 2011/12 average tariff revenue amount of 22.93 c/kwh to an average tariff revenue of 29.74 c/kwh in 2015/16.

This move towards cost reflectivity can be achieved in many ways; for example, the tariffs can follow the cost reflective amounts in each year or can be smoothed over the four-year

[9] Based on the Authority's estimate of Synergy's carbon costs.

period. Ultimately, this is a decision for the government since setting tariffs for Synergy is outside the scope of the Authority's functions. However, for illustrative purposes, the Authority has undertaken the bill impact analysis for residential customers, on a smoothed basis (that is, equal rate of increase in each year, after the initial increase in 2012/13 that has been announced in the government's current budget). On this basis, the bill impact for residential customers will be $207 in 2012/13, followed by an increase of between $115 and $135 per year.

With regard to large contestable customers, the Authority recommends the removal of regulated tariffs for the M1, S1 and T1 customers. Given average annual expenditure on electricity by these customers, they are likely to be able to negotiate a fair contract with a retailer of their choice. The Authority also notes that tariffs for customers greater than 160 MWh are not regulated anywhere else in Australia.

Whilst the Authority has identified the TEC as a non-efficient cost and recommends its removal, the government has indicated that the TEC will be retained. In contrast with the cost reflective tariffs given in Table 1 above, Table 2 below shows tariffs for 2012/13 to 2015/16 for which all components are cost reflective, other than the inclusion of the TEC. The result of including the TEC is an average increase across all tariffs.

Table 2 Individual Tariffs; TEC Inclusive but Otherwise Cost Reflective (c/kwh, nominal) 2012/13 to 2015/16

Tariff	Tariff Description	2011/12 Actual	2012/13 Budget	2012/13 Budget + Carbon[10]	2012/13 Cost Refl.	2013/14 Cost Refl.	2014/15 Cost Refl.	2015/16 Cost Refl.
	Non-contestable							
A1	Residential	22.34	23.12	25.37	30.42	30.50	31.11	32.60
B1	Residential water heating	14.25	14.74	17.00	20.20	20.27	20.75	21.75
C1	Non-profit organisations	22.26	22.77	25.02	27.10	27.21	27.51	28.77
D1	Charitable residential	18.79	17.91	20.16	26.50	26.81	27.08	27.81
K1	Mixed commercial & residential	23.75	24.58	26.83	29.18	29.28	29.78	31.05
L1	Low voltage supply (<50 MWh)	24.02	24.86	27.11	29.59	29.67	30.17	31.48
R1	Time-of-use tariff (<50 MWh)	17.37	17.97	20.23	31.55	31.69	32.12	33.57
W1	Traffic lights	22.91	25.66	30.18	26.19	26.40	26.76	28.38
Z1	Street lights	36.50	34.68	35.12	40.17	40.59	41.47	42.95
UMS	Unmetered supply	22.91	24.06	30.18	21.64	21.72	22.06	23.21
	Contestable							

[10] Based on the Authority's estimate of Synergy's carbon costs.

L3	Low voltage supply (>50 MWh)	29.04	30.90	31.74	28.48	28.59	29.12	30.37
M1	General supply (high voltage)	25.21	26.02	29.64	28.02	29.32	29.92	30.75
R3	Time-of-use tariff (>50 MWh)	23.25	24.53	26.04	23.64	23.63	24.07	25.29
S1	Low/med voltage time-of-use	19.33	21.26	23.94	23.63	23.57	23.93	25.11
T1	High voltage time-of-use	18.56	20.79	22.86	22.36	22.32	22.65	23.77
	Average across all tariffs	**22.93**	**23.77**	**25.89**	**29.37**	**29.45**	**30.04**	**31.50**

Source: ERA Analysis

Impact on Synergy and Government

From 2012/13 onwards the Authority's estimate of Synergy's efficient costs[11] is between $69 and $95 million less than Synergy's estimates of Synergy's forecast costs (excluding TEC).

The difference between the revenue recovered from cost reflective tariffs and actual tariffs that Synergy charges its customers, is covered by government funded operating subsidies. The Authority considers that the operating subsidies should be based on the difference between revenue and efficient costs, rather than the difference between revenue and the actual costs Synergy incurs. If Synergy cannot achieve the cost reductions required to meet the efficient level of costs, dividends and tax-equivalent payments to government will be affected.

The Authority has considered the financial impact on government under two scenarios. Each scenario assumes tariffs in 2012/13 are set at the level indicated in the 2012/13 Budget, including an increase for carbon.

Under Scenario 1, tariffs in 2013/14 are increased by 7 per cent to achieve cost reflective levels, and then are maintained at cost reflective levels in each subsequent year.

- If Synergy's costs are reduced to an efficient level, which is likely to involve the writing down of contract values, there will be no ongoing subsidy to Synergy (the subsidy to Horizon Power would be paid directly out of consolidated revenue).
- If Synergy's costs are not reduced to an efficient level, but remain at the actual projected level, the difference between tariff revenue and costs would be $49 million in 2013/14, $66 million in 2014/15 and $58 million in 2015/16.
- If the TEC continues to be recovered from tariffs, the increase in tariffs in 2013/14 would need to be 14 per cent to achieve cost-reflective levels.[12] If the government were to accept the Authority's recommendation to remove the TEC (and replace it with an operating subsidy paid directly to Horizon Power), the government would need to fund the operating subsidy.

Under Scenario 2, equal rate of tariff increase is applied each year, starting in 2013/14 until cost reflective tariffs are achieved in 2015/16 (this is referred to as a "glide path" and requires tariffs to increase between 4 and 5 per cent each year).

[11] Including costs to service both tariffs and market based contracts.

[12] This amount will recover only the proportion of the TEC attributable to Synergy's tariff customers of $129.8 million including retail margin.

- If Synergy's costs are reduced to an efficient level, an operating subsidy to Synergy will continue until cost reflectivity is achieved. This subsidy would be $64 million in 2013/14 and $6 million in 2014/15.
- If Synergy's costs are not reduced to an efficient level, but remain at the actual projected level, the difference between tariff revenue and costs would be $113 million in 2013/14, $73 million in 2014/15 and $58 million in 2015/16.
- If the TEC continues to be recovered from tariffs, the annual increase in tariffs would need to be between 6 and 7 per cent per year. Alternatively, if the TEC were paid directly to Horizon Power as an operating subsidy, the government would need to fund the operating subsidy.

Future Regulatory Arrangements

The Terms of Reference for the inquiry require the Authority to consider whether regulated tariffs for contestable customers should be phased out.

Contestable customers are those who consume over 50 megawatt hours of electricity per year. They may pay the regulated tariff rate to purchase electricity from Synergy, or may negotiate a contract with Synergy or another electricity retailer.

The key principle applied by the Authority is that a competitive market for large business customers is preferable to regulated tariffs. However, this is only possible where there is effective competition between alternative electricity retailers for these customers.

The Authority's assessment of the contestable market suggests that there remain some significant barriers to effective competition. The wholesale market needs to mature further with improvements in the number and size of competing retailers. Synergy still retains around 50 per cent[13] of the contestable market in the South West Interconnected System (**SWIS**). However, the Authority does not consider the tariffs to be a barrier to competition, as the tariffs for contestable customers are already close to cost reflective levels (on a TEC exclusive basis).

The Federal Government has announced a fixed price for carbon for the first three years, 2012/13 to 2014/15. However, from 2015/16, the carbon price will no longer be fixed, and will be set by the market. Hence, the carbon price for 2015/16 is uncertain, and accordingly, the Authority recommends that the next inquiry into the efficiency of Synergy's costs and electricity tariffs be conducted in 2014/15 rather than at the end of the four year review period. This will allow for a timely assessment of any movement in Synergy's carbon cost arising from changes in carbon price.

[13] Synergy (2011), Annual Report, p1.

Recommendations and Findings

Overall Findings

1. The Authority finds that Synergy's actual cost is more than the overall efficient cost of supplying retailer services, and its tariffs are below efficient cost reflective levels.

2. The Authority finds that for residential customers, Synergy's actual cost is more than the overall efficient cost of supplying retailer services, and its tariffs are below efficient cost reflective levels.

Specific Findings

3. The Authority considers Synergy's demand forecasting approach and assumptions to be appropriate and has accepted Synergy's demand forecasts for the pricing period.

4. The Authority considers Synergy's methodology and estimates for dispatching energy to be efficient.

5. The Authority recommends the use of LRMC for calculating the efficient wholesale electricity cost.

6. The Authority does not consider the pass-through of Synergy's actual cost of carbon to customers to be efficient. The Authority regards the carbon cost built into the LRMC calculation to be consistent with carbon cost that would be expected in a competitive market.

7. The Authority considers Synergy's procurement of RECs to be efficient.

8. The Authority recommends the adoption of an average retail operating cost allowance of approximately $81 per customer (in 2011/12 dollars) for the review period.

9. The Authority finds that retail operating costs should be escalated by 3.58 per cent over the review period.

10. The Authority has separately accounted for depreciation in Synergy's cost, and the Authority considers that the average annual depreciation cost of $15.20 per customer, to be appropriate. This amount excludes capital recovery for expenditure on IT in excess of budgeted amounts.

11. Synergy has little control over its ancillary services costs. The Authority therefore recommends that forecast costs for ancillary services be included in the costs to be recovered from Synergy's customers.

12. As a participant in the WEM, Synergy cannot avoid market fees and has little influence on the expenditures incurred by the IMO and System Management. The Authority therefore considers that it is appropriate for Synergy to recover the payment in full from its customers.

13. The Authority considers Synergy's forecasting uncertainty risk is appropriately taken into account in its rate of return, and that it is therefore inappropriate to include balancing costs in Synergy's efficient cost stack.

14. Any differences between forecast and actual non-controllable costs should be adjusted for in real terms at the next major review.

15. The Authority has found that an appropriate retail margin for Synergy for the next four years is 3.5 per cent of its total cost.

16. The Authority considers that the B1 Residential Hot Water Tariff should be removed, or merged with the A1 Tariff. There is no justification for merging any other tariff categories at this stage.

17. The Authority recommends that the subsidy to Horizon Power be provided by a CSO rather than the TEC, and notes that this CSO will be partially offset as a result of moving to cost reflectivity.

18. The Authority recommends removal of regulated tariffs for the M1, S1 and T1 tariffs.

19. The Authority recommends that the next inquiry into the efficiency of Synergy's costs and electricity tariffs be conducted in 2014/15 rather than at the end of the four year review period, to allow for a timely assessment of changes in Synergy's carbon cost.

20. The Authority recommends that if there are significant changes to economic conditions, a mid-period review should be undertaken.

1 Introduction

The Treasurer of Western Australia gave written notice to the Authority, on 11 July 2011, to undertake an inquiry into the efficiency of Synergy's costs and electricity tariffs. The inquiry has been referred to the Authority under Section 32(1) of the *Economic Regulation Authority Act 2003*. This provides for the Treasurer to refer inquiries to the Authority on matters relating to regulated industries.[14]

1.1 Terms of Reference

The Terms of Reference, which are presented in Appendix A, require the Authority to consider and develop findings on:

- the efficiency of Synergy's operating and capital expenditure;
- the efficiency of Synergy's procurement of wholesale electricity; and
- the efficiency of Synergy's procurement of renewable energy certificates.

The Terms of Reference also require the Authority to determine the efficient cost reflective level for each regulated tariff listed under the By-laws[15] for the review period 2012/13 to 2015/16, including:

- developing recommendations regarding the number of regulated electricity tariffs and whether any tariffs should be amalgamated; and
- taking into account the competitive markets within which Synergy operates and the current operating subsidy arrangements, when considering the cost reflective level of each tariff.

The Authority is also to develop a methodology to regularly re-determine the efficient cost reflective level for each tariff and recommend a period for the regular review of cost reflective tariffs. In doing so, the Authority is also to consider:

- whether regulated tariffs for contestable, large business consumers should be phased out, with reference to the competitive nature of this segment of the electricity market; and
- if regulated, large, contestable tariffs are to be phased out, provide recommendations on which tariffs should be phased out and over what timeframe.

The Terms of Reference require the Authority to prepare and release an issues paper to facilitate public consultation for the inquiry. The issues paper provides background information on Synergy and the issues under review and invites written submissions from industry, government and all other stakeholder groups, including the general community.

The Terms of Reference also provide for a second round of public consultation, following publication of a draft report during the timeframe for the inquiry. The Treasurer amended the Terms of Reference to extend the due date for the delivery of the Final Report from 31 December 2011 to 1 June 2012, after which the Treasurer has 28 days to table the report in Parliament.

[14] *Economic Regulation Authority Act 2003*, p19

[15] These are the Energy Operators (Electricity Retail Corporation) (Charges) By-Laws 2006 – Schedule 1

1.2 Background to the Inquiry

Under the current uniform tariff policy, small-use residential and business customers across the State pay the same tariffs for electricity, regardless of their location. However, the revenue collected from these tariffs does not fully cover the costs of supplying electricity in Western Australia. The overall shortfall between uniform tariff revenue and the actual cost of supplying electricity is met through various subsidies from the State Government.

In 2007/08, the Office of Energy (**OoE**), now the Public Utilities Office (**PUO**), conducted a review of the Western Australian retail electricity market and published its findings in January 2009. The OoE report noted that, at that time, regulated residential retail tariffs had not increased since 1997/98. This was in contrast to the Eastern States, which had, over the period 1997/98 to 2007/08, experienced significant increases in residential electricity prices, ranging from 23 per cent to 69 per cent.[16]

The OoE report also considered that the move toward cost reflective retail tariffs was essential to the development of a competitive electricity retail market in the State. The report noted that:

> If retail tariffs do not reflect the cost of supplying electricity (including an appropriate margin), then retailing electricity will not be a viable business activity.[17]

Cost reflective tariffs and competition in the electricity market help to ensure that energy resources are put to their best use. This is achieved by encouraging enterprise and efficiency among energy suppliers, and sending appropriate price signals to customers to enable them to modify their energy usage.

In moving towards cost reflective retail tariffs, customers have seen considerable tariff increases over recent years. The percentage increases in residential and small business tariffs from 2009, as well as budgeted forecasts to 2014/15, are shown in below.

Table 3 Tariff Percentage Increases 2009/10 to 2014/15

	Actuals			Forecasts			
Tariff	**April 2009**	**July 2009**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
Residential (A1)	10%	15%	25.9%	5%	5%	12%	12%
Small business (L1)	5%	10%	25.9%	5%	5%	12%	12%

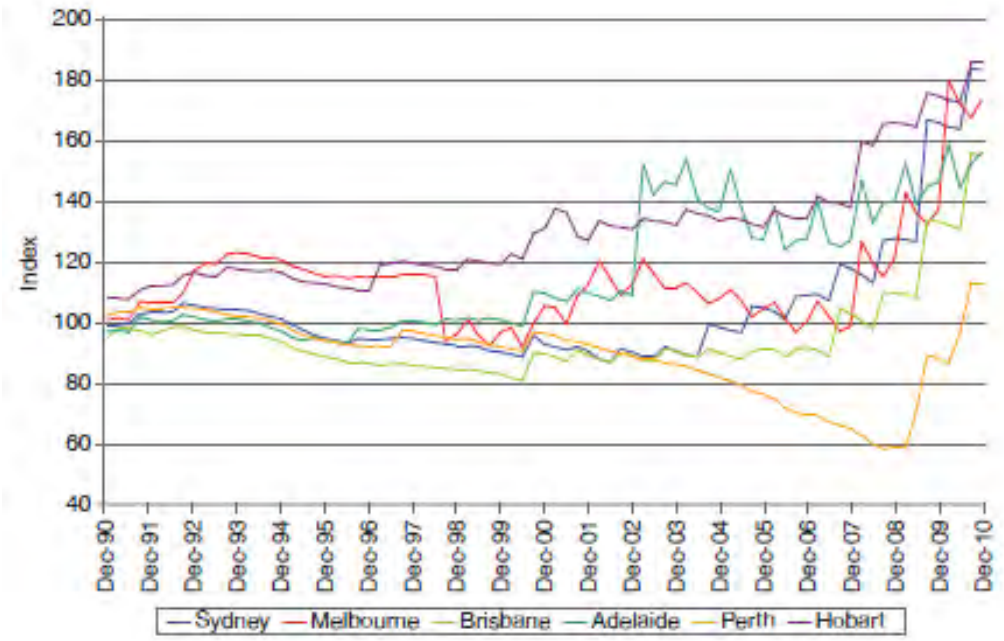
Source: State Budget Paper No. 3 (2009/10 and 2011/12), pp. 276 and 286 respectively

Prior to the tariff increases in 2009, electricity prices in Western Australia had fallen in real terms, since 1990. Figure 3 shows the movement in real residential electricity prices in Perth (that is, adjusted for inflation) in comparison to those in other capital cities over the period from 1991 to 2010.

[16] Office of Energy (2009), Electricity Retail Market Review, Final Recommendations Report, p6

[17] Ibid.

Figure 3 Index of Real Residential Electricity Prices in Australian Capital Cities



Source: Office of Energy (June 2011), Tariff and Concessions Framework Review: Issues Paper, p9

This inquiry will determine cost reflective tariffs for Synergy and, in doing so, inform the government of the level of the subsidy required (if any) to meet the shortfall in revenue over the review period. To determine the level of cost reflective tariffs, the Authority will need to consider Synergy's operating and capital expenditure, procurement of wholesale electricity and procurement of renewable energy certificates.

1.3 Review Process

The recommendations from this inquiry have been informed by the following public consultation process:

- The Authority published an issues paper on the inquiry on 11 August 2011 and invited submissions from stakeholder groups, industry, government and the general community, on the matters in the Terms of Reference. The due date for submissions was 9 September 2011.
- Seven submissions were received in response to the issues paper, which are published on the Authority's website[18].
- The Authority has consulted with its Consumer Consultative Committee (**ERACCC**) over the course of the inquiry.
- Following consideration of the submissions, the Authority developed a draft set of recommendations, presented in the publication *Inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs: Draft Report* (**Draft Report**), and invited a further round of submissions from stakeholder groups, industry, government and the general community. The due date for the submissions was Monday 2 May 2012.

[18] www.erawa.com.au

- The Authority considered the nine submissions received and developed the set of recommendations presented in this Final Report, which was delivered to the Treasurer on 1 June 2012. The Treasurer, in accordance with the Act, will have 28 days to table the report in Parliament.

In accordance with Section 45 of the Act, the Authority acted through the Chairman and Members of the Governing Body in conducting this inquiry.

Further information regarding this inquiry can be obtained from:

Helen Ensikat
Project Manager, References and Research
Economic Regulation Authority
Ph: (08) 6557 7900

Media enquiries should be directed to:

Richard Taylor
Riley Mathewson Public Relations
Ph: (08) 9381 2144

2 Inquiry Approach

2.1 Aim of the Inquiry

This inquiry aims to establish the cost reflective tariffs for Synergy and, in doing so, inform the government on the level of the subsidy required (if any) to meet the shortfall in tariff revenue over the review period. To determine the level of cost reflective tariffs, the Authority has considered the efficiency of Synergy's operating and capital expenditure, procurement of wholesale electricity and procurement of renewable energy certificates. The Authority has formed an opinion as to whether any tariffs should be amalgamated, developed a methodology to regularly re-determine the cost reflective level of each tariff, and considered whether regulated tariffs for large business customers should be phased out.

A description of the electricity sector in Western Australia, including the structure of the industry and an overview of the key market participants, and Synergy's operations and tariffs, is provided as background information in Appendix B.

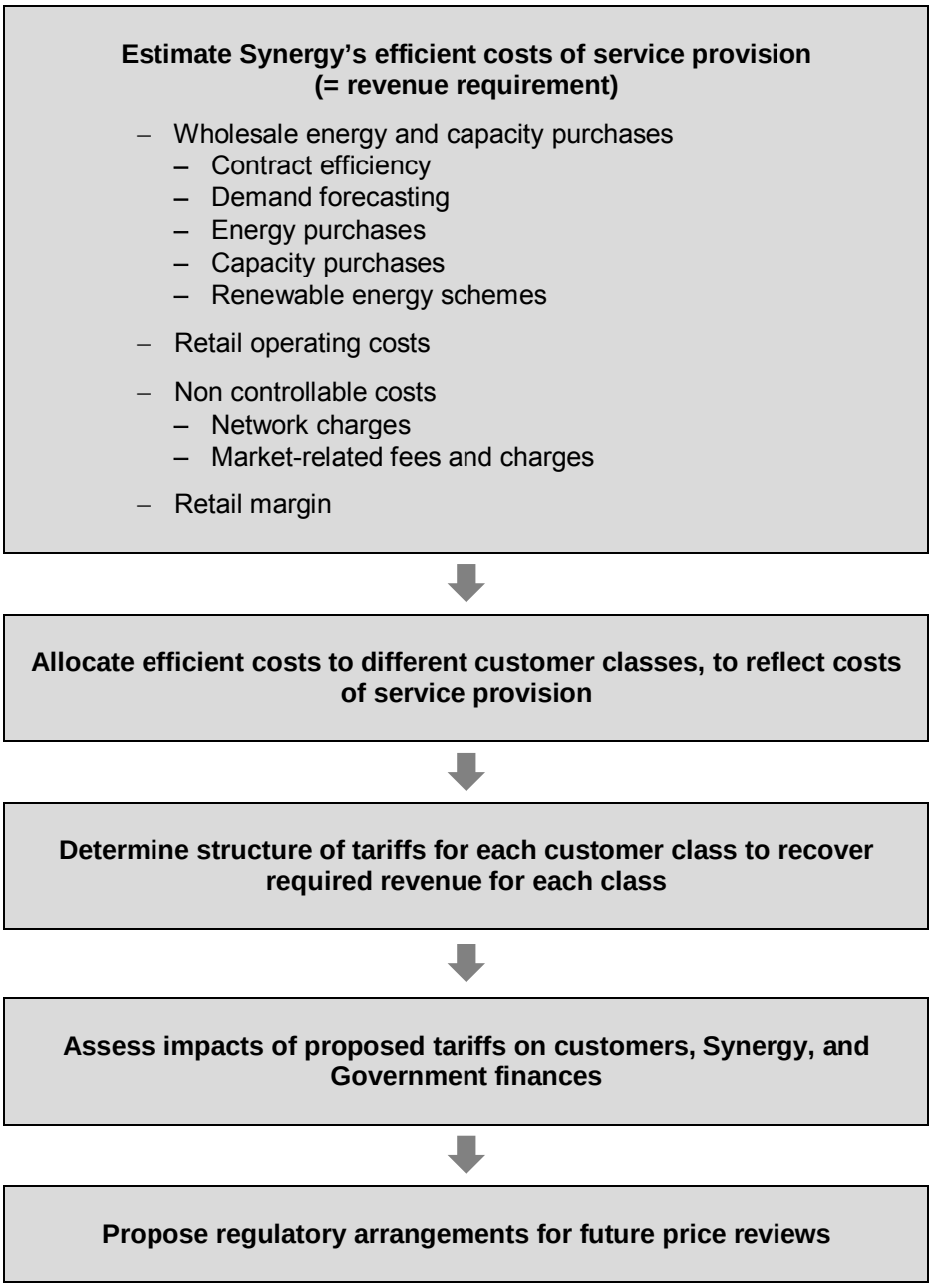
2.2 Current Process for Setting Tariffs

The approach to calculating the cost reflective tariffs that were used in the OoE's 2007/08 Electricity Retail Market Review can be described as a 'cost-stack escalation' approach. This involves creating a 'cost stack' for electricity retail services, usually on a per kWh basis. This cost stack is the average cost of delivered energy for each year.

2.2.1.1 Authority's Recommended Method

The Authority has also applied a cost-stack approach to the estimation of cost reflective electricity retail tariffs. The Authority's method is summarised in Figure 4 below.

Figure 4 Authority's Approach to Determination of Cost Reflective Electricity Retail Tariffs



2.2.2 Economic Efficiency

The Authority's recommendations on costs and tariffs in this inquiry are guided by the principle of economic efficiency. In an efficient market, the goods and services that are produced are the ones that are most valued by society, produced at least cost, and allocated to those who value them most highly, thereby maximising community well-being. There are a number of dimensions to economic efficiency. These include:

- Allocating resources to their most productive use ("allocative efficiency"), which can be achieved by setting the prices of goods and services to reflect the cost of providing an additional unit of the good or service.

- Providing goods and services at least cost ("productive efficiency" or "technical efficiency"), which can be achieved, for example, through using the most efficient, least-cost production technologies or management methods that reduce costs, without compromising service standards.
- Ensuring that investments are optimal over the long-term, in their timing and location ("dynamic efficiency"; that is, taking into account change over time). An example of this is timing capital investments so that costs are minimised over the long-term, and that they reflect any changes in consumer preferences and available technology over time.

Economic efficiency is a forward-looking concept. That is, in order to make efficient decisions at any point in time, the relevant consideration is one of how future well-being can be maximised, given that past decisions or investments have already been made. Therefore, the revenue requirement for a regulated business is determined on the basis of the forward-looking efficient costs that the business needs to provide its services to the required standard.

Competition is an effective tool for encouraging efficiency. In competitive markets producers compete for customers by reducing prices and/or improving quality. To profitably do this, producers need to improve their productive efficiency to reduce their production costs, and consumers need to be able to switch easily between the providers of goods or services. In competitive electricity retail markets, competition between retailers to retain and acquire customers can drive down the cost of retail services, while maintaining service quality, as long as customers are easily able to choose and switch between retail service providers.

There are a number of retail electricity markets around Australia, with varying degrees of competition. In effectively competitive markets, tariffs are likely to reflect efficient costs. In markets that are not fully competitive, actual costs may differ from efficient costs. This may be because there are barriers to entry to the market, such as regulations that deem some types of customers non-contestable. In this case, the costs of service provision by the incumbent retailer are likely to be higher than the costs that would be incurred in a competitive market.

The Authority has been guided in its assessments of efficient costs by the efficient new entrant prices demonstrated in other electricity markets in Australia that have full retail contestability.

However, in doing so, the Authority is cognisant that the retail and wholesale market structure in Western Australia is different to the market structures that exist in the Eastern States. For example, the Wholesale Electricity Market (**WEM**) in Western Australia is part capacity and part energy market,[19] whereas the National Electricity Market (**NEM**; that is, the wholesale electricity market in the Eastern States) is an energy only market. Furthermore, the input cost assumptions in Western Australia may be different to those used in the Eastern States; e.g. fuel costs or wage costs in Western Australia may differ from those interstate. The Authority has ensured that in its assessment of efficient costs, it has given due consideration to any differences arising from different operating environments and contextual factors.

[19] For a full description of the structure of the Western Australian electricity industry and the operations of the wholesale electricity market, see Appendix B.

Apart from these differences in operating conditions and market structure, Synergy's costs can also be influenced by government directives and obligations that are imposed on it due to its public ownership. This cost impost is not directly related to Synergy providing services to its customers and therefore should not be reflected in tariffs. The Authority does not consider these costs to be part of its efficient cost estimates; instead, these costs are appropriately borne by the government, rather than by Synergy's customers. These costs generally relate to areas such as social policy, e.g., concessions for low-income consumers and assistance to customers experiencing financial hardship.

Once efficient costs are established, the gap between actual costs and efficient costs can be determined. Tariffs can be determined to recover efficient costs in a way that reflects the costs of service for different types of customers. In constructing tariffs, it is important to take into account the impacts on customers of moving towards cost reflective prices, for example, by setting a transition path from actual tariffs towards cost reflective tariffs that minimises price shocks.

2.2.3 Estimation of Synergy's Efficient Costs

As indicated above, the Authority has adopted a cost-stack approach to determining the efficiency of each type of Synergy's costs in this report. The cost components of this building block approach are:

- wholesale electricity procurement costs (capacity and energy purchases);
- network charges, paid by network users to Western Power, the electricity network owner and operator, to cover the costs of providing network services;
- market fees, paid by Synergy to the Independent Market Operator (**IMO**) to recover the costs of operating the WEM;
- ancillary service costs, paid by Synergy to the IMO to recover the costs of services administered by System Management (i.e., a branch of Western Power) to ensure system security and reliability, quality of supply, and orderly trading on the electricity market;
- costs of meeting obligations of Mandatory Renewable Energy Targets (**MRETs**);
- costs to Synergy of meeting its Reserve Capacity Requirement (**RCR**);
- retail operating costs (the costs of Synergy's retail activities, such as billing, customer services, revenue collection, information provision, administration, data collection and management); and
- retail margin (the appropriate margin to be provided to Synergy's shareholders to compensate them for the risks associated with the business).

The approach that the Authority has applied in considering each of these cost categories is explained below.

Wholesale Electricity Procurement Costs

In purchasing electricity to meet demand, Synergy is required not only to participate in the energy market to purchase electricity, but also in the capacity market to purchase generation capacity. As part of the assessment of Synergy's efficient costs of electricity procurement, the Authority has examined:

- The existing contracts between Synergy and electricity generators, to assess whether the processes that Synergy adopts in tendering for and negotiating energy supply contracts are consistent with the efficient procurement of electricity;
- Synergy's demand forecasting methodology. Demand forecasts form the basis of Synergy's cost and revenue forecasts. Accordingly, the Authority has examined the assumptions used by Synergy in its demand forecast models, as well as comparing the performance of Synergy's demand forecasts against actual demand.
- Synergy's procurement of electricity using its current portfolio of contracts. To assess this, the Authority has conducted detailed modelling of the cost of energy procurement, taking into account:
    - all the terms and conditions specified in each contract;
    - Synergy's obligations in terms of meeting its requirements for purchasing generation capacity;
    - Synergy's obligations with regard to purchasing wholesale energy to meet demand; and
    - Synergy's obligations with regard to purchasing from renewable energy sources.
- The Long Run Marginal Cost of generation to meet Synergy's load.

Non Controllable Costs

Some costs such as network charges, ancillary services costs, market fees and balancing costs, are outside the control of Synergy, and so would be passed through to customers.

In regard to the other cost-stack components, the Authority proposes to accept Synergy's estimates of market fees, ancillary services charges, MRET quantities and costs, and costs of unhedged reserve capacity requirements (**RCRs**) (which typically account for around 5 per cent of Synergy's total costs). The carbon pricing liability is calculated as part of the energy cost calculation.

The network tariff is also a straight pass-through of the Authority's draft decision on Western Power's third revised Access Arrangement (**AA3**). Network charges typically account for around 33 per cent of the total retail tariff, excluding the TEC (or 42 per cent including the TEC).

Retail Operating Costs

Retail operating costs are those costs associated with billing and revenue collection, operating call centres, managing customer information, energy trading, regulatory compliance, marketing and overheads. The principle when setting a revenue allowance to recover efficient retail operating costs is to estimate the costs that would be incurred by retailers operating in a competitive market. The relevant benchmarks, therefore, are retailers in markets where there is full retail contestability.

The Authority has engaged consultants to assess the efficient retail operating costs of Synergy, by benchmarking Synergy's costs against comparable retail service providers.

Depreciation

For electricity retailers, capital costs are a small proportion of their costs, relating mainly to assets such as computing and telephone systems. The majority of Synergy's costs are those associated with network charges and energy purchasing. However, it is reasonable that Synergy be provided with an appropriate return of its investments, to recover the costs of the depreciation of its assets over their useful lives.

Retail Margin

The question when setting a retail margin for Synergy is: what margin would an efficient retailer, operating in a competitive environment, earn on its investments? The retail margin is a proxy for the return on investment, such as the Weighted Average Cost of Capital (**WACC**) applied to the asset base of other regulated service providers. However, in the case of electricity retail businesses, it is difficult to determine the value of the asset base, as most of the assets are intangible.

The Authority has conducted its own assessment of an appropriate retail margin for Synergy, taking into account the levels of retail margins provided to comparable electricity retailers, the value of Synergy's (mainly intangible asset base), as well as an assessment of the risks associated with the services provided by Synergy.

2.2.4 Allocating Costs to Customer Classes

Once the efficient costs for each of the various cost components have been estimated, the report recommends how these costs should be allocated to the different tariff classes and what the cost reflective tariff should be for each class.

Synergy has three broad customer classes, with these being further divided into individual tariff classes (see Appendix C). These are:

- Regulated non-contestable customers, being customers within the South West Interconnected System (**SWIS**) consuming less than or equal to 50 megawatt hours of electricity per year. These customers pay tariff rates determined by the State Government and are supplied exclusively by Synergy.
- Regulated contestable customers, being customers within the SWIS who consume over 50 megawatt hours and less than 160 megawatt hours of electricity per year. These customers may pay the regulated tariff rate to purchase electricity from Synergy, or may negotiate a contract with Synergy or another electricity retailer.
- Non-regulated customers, being customers who consume 160 megawatt hours of electricity or more per year. These customers may choose to enter a market based contract with Synergy or enter a contract with an electricity retailer of their choice. Although these customers do not pay regulated tariffs, and are therefore outside the scope of this inquiry, they share Synergy's joint costs (such as management costs). As such, they are taken into account to ensure that joint costs are appropriately shared between regulated and non-regulated customers.

There are a number of methodologies available to determine an appropriate allocation of energy costs across Synergy's various tariff classes.

In considering an appropriate allocation methodology, the Authority has been guided by the principle that various customer classes should, to the extent calculable, incur only costs relating to the electricity consumed by that customer class. As such, the allocation process adopted by the Authority is intended to mitigate the occurrence of cross-

subsidisation between customer classes. Additionally, it is intended to prevent, for example, residential customers paying a higher tariff that captures costs more reasonably allocated to Synergy's large business customers.

2.2.5 Tariffs

For each of the three customer categories (being regulated, contestable regulated and non-regulated customers) the Authority has calculated cost reflective cost stacks for each customer class.

In determining the efficient cost for each customer class, the Authority has had regard to the principles of price stability, cost reflectivity, transparency of the price setting methodology, and the minimisation of any associated administrative costs.

2.2.6 Gap Analysis

For each customer category, the Authority has identified the gap between actual tariffs and cost reflective tariffs.

Consideration has been given to the impact of a transition from the actual tariffs to cost reflectivity. In considering possible transition paths, the Authority recognises the importance of avoiding price shocks and providing a level of certainty to customers and other market participants.

Furthermore, the Authority has assessed the potential impacts of a transition on retail customers, Synergy and the Western Australian Government.

3 Wholesale Electricity Procurement Costs

In this section, the efficient costs required by Synergy to purchase wholesale electricity and Renewable Electricity Certificates (**RECs**) are examined.

3.1 Background

The Terms of Reference require the Authority to consider the efficiency of Synergy's procurement of wholesale electricity and RECs. Over the past four years these two items have contributed approximately 57 per cent of Synergy's total aggregated costs[20] for the period.

The Authority has adopted two approaches to assessing the efficiency of Synergy's procurement of wholesale electricity:

- reviewing Synergy's actual wholesale electricity procurement in order to determine the efficiency of Synergy's actual wholesale electricity costs; and
- using the Long Run Marginal Cost (**LRMC**) of wholesale electricity as an indicator of the efficient cost of procuring wholesale electricity.

3.2 Draft Report

The Authority made a number of recommendations in relation to wholesale energy costs in the Draft Report. The Authority considered that:

- Synergy's energy consumption forecasting processes were efficient and accepted Synergy's energy forecasts for the period 2012/13 to 2015/16;
- Synergy's methodology and estimates for dispatching energy were efficient;
- Synergy's procurement of Renewable Energy Certificates was efficient;
- the LRMC of efficient wholesale electricity supply was below Synergy's forecast average cost:
    - the LRMC was slightly lower than Synergy's forecast average cost of dispatch in 2012/13, mainly due to the new entrant generator having a lower carbon intensity; and
    - from 2014/15 onwards, the LRMC was substantially below Synergy's forecast average cost of dispatch, due to the new entrant generator having both a lower energy cost and a lower carbon cost ;
- Synergy may not be able to respond immediately to the carbon price;
    - as a result, while LRMC provides an indication of the efficient level of cost over time, the Authority has chosen to adopt Synergy's actual contract costs for 2012/13 and 2013/14, followed by the LRMC approach for the following two years, when determining Synergy's efficient costs.

[20] The cost of procuring wholesale electricity is included in this cost. The total cost for Synergy in 2009/10 was approximately $2bn.

3.3 Public Submissions

3.3.1 Wholesale Energy Procurement

Synergy

Synergy's submission provided a number of comments regarding the Authority's findings on wholesale energy costs, with key points:

- the Authority's estimates of the LRMC lead to a lower LRMC than that faced by a new entrant retailer, as Synergy's contract customers have a higher capacity factor than the Synergy tariff customers;
- the Authority's wholesale contract optimisation process should be reviewed to ensure all relevant contractual constraints have been incorporated;
- the use of LRMC requires the total load to be met by gas fired generation, which is unrealistic, furthermore, there would be a significant increase in gas prices.

Public Utilities Office (Department of Finance)

The Public Utilities Office (**PUO**) indicated that the Authority's adoption of LRMC in 2014/15 and 2015/16 is inappropriate, as it is unreasonable to assume Synergy can transition to LRMC in two years, particularly given the calculated LRMC requires a movement towards gas fired generation that does not account for existing coal generation in the system.

Additionally, the PUO questioned the gas prices adopted by Frontier Economics, given the likely pressure on gas prices and pipeline capacity arising from increased demand for gas.

Verve Energy

Verve Energy made a number of key points in response to the Draft Report, including that:

- the process undertaken to negotiate the Replacement Vesting Contract (**RVC**) was independently reviewed to establish that it was both fair and reasonable, and that the contract was not externally imposed on either party;
- the adoption of a new entrant methodology has resulted in a material underestimation of LRMC, given that the optimal generation mix determined by this methodology is not achievable;
- the capital costs attributed to some generation plant in the modelling to determine the optimal LRMC generation mix in the SWIS by Frontier appear to be significantly underestimated;
- the Authority had adjusted the costs of procuring capacity in the WEM to levels higher than those suggested by the LRMC model, so as to be consistent with actual capacity costs on the WEM, such that the Authority deviates from the pure theoretical LRMC model;
- the gas price assumptions used by Frontier Economics in the LRMC calculation are lower than the likely market price for long term gas supply contracts in the Western Australian market.

ERM

ERM submitted that, in its experience of the Western Australian wholesale market, the cost reflective wholesale energy prices calculated by the Authority are incompatible with the wholesale product available in the market, particularly for S1 and T1 tariff customers.[21] ERM considers that the S1 and T1 tariffs are well below cost reflective prices. ERM consider that customer churn is low in the WEM because independent retailers cannot profitably compete with the regulated tariff.

Horizon Power

Horizon Power submitted that two years is insufficient to transition from actual cost to LRMC, and that this transition period should be extended to reflect the practical activities necessary to effect any changes.

3.3.2 Renewable Energy Certificates

Synergy

Synergy indicated that the LRMC calculations should account for the purchase of Large Scale Renewable Energy Target (**LRET**) certificates (otherwise referred to as Large-scale Generation Certificates; **LGCs**) on a long term basis. The modelling undertaken by Frontier ignores any LRET obligation and therefore, does not include any renewable generation in the calculation of the efficient LRMC cost.

Horizon Power

In relation to Synergy's procurement of LGCs, Horizon Power noted that the price of LGCs is sensitive to market conditions, fluctuating accordingly, and is of the opinion that the average market price of LGCs will increase over time, placing a larger burden on those companies subject to this legislative requirement.

3.3.3 Carbon Costs

Synergy

Synergy submitted that actual carbon costs in a bilateral market such as the WEM are subject to contractual 'change in law' pass through from the contract generator. As the majority of Synergy's wholesale contracts have a remaining life of 10 years or more, it is inconceivable that carbon costs would decline consistent with the carbon intensity of the marginal generator, as suggested by the Authority;

Synergy further noted that its existing wholesale electricity supply contracts were negotiated prior to the implementation of the current carbon scheme.

[21] S1 tariffs are charged to low/medium voltage time- of-use contestable customers. T1 tariffs are charged to high voltage time-of-use contestable customers.

Additionally Synergy recommended that allowances for the unpredictability of wind generation and for potential Scope 2 and 3 emissions costs[22] be incorporated into calculations of carbon intensity.

Public Utilities Office (Department of Finance)

The PUO expressed an opinion that the full cost of carbon will be passed through, and it appears overly ambitious to expect Synergy to renegotiate contracts with these generators within a two year window. It requested that the Authority consider options other than the LRMC approach to effect a transition to efficient carbon costs.

Verve Energy

Verve Energy considered that the Authority's treatment of the pass through of carbon costs may be appropriate in a gross pool market such as the NEM, but that it is not appropriate to apply this to the WEM which is based on bilateral contracts. It comments that the majority of existing bilateral contracts in the WEM were negotiated prior to the implementation of the current carbon scheme, and that there is currently no explicit mechanism for passing on these costs, although all contracts include a 'change in law' provision. Verve Energy does not consider that Synergy will be able to renegotiate is contracts to ensure that only an efficient level of carbon cost is recovered in tariffs within the two year period recommended by the Authority.

Horizon Power

Horizon Power concurred with the Authority's view that Synergy (or any other existing electricity service provider) will be unable to respond immediately to the carbon price by amending existing electricity supply agreements.

However it submitted that two years is insufficient to transition from actual contract costs to the LRMC costs to service, and that this transition period should be extended to reflect the practical activities necessary to progress to an optimal generation mix.

3.4 Use of the LRMC Approach to Determining Efficient Tariffs

As noted above, the Authority approached the requirements of the Terms of Reference by estimating:

- **Synergy's forecast wholesale electricity procurement costs** – the Authority has examined Synergy's forecast of the wholesale electricity costs that it will incur through its contracting for capacity and energy, its dispatch of energy from these contracts and expected transactions in the wholesale electricity market to meet any shortfalls. The Authority has taken into account each of the bilateral contracts that Synergy has entered into, including the RVC that exists between Synergy and Verve Energy. These contracts include agreements for energy and the capacity that Synergy is required to procure to meet its expected load.

[22] Scope 2 emissions are direct emissions from fuel combustion associated with electricity generation or steam raising. Scope 3 emissions are other emissions associated with inputs to production, such as fugitive emissions created during natural gas extraction and transport.

- **The LRMC of energy to serve Synergy's load** – the LRMC of energy is an indicator of the cost of procuring wholesale electricity in an effectively competitive market, in the long run. The use of the LRMC of energy to inform the efficient cost reflective level for Synergy's total load profile is consistent with the economic efficiency principles outlined earlier in Section 2.2.2.

A number of submissions in response to the Authority's Draft Report questioned the appropriateness of the Authority's LRMC approach. These submissions are addressed in the following sections.

3.4.1 Applicability of LRMC in Efficient Cost Determination

A particular challenge for the Authority in this inquiry has been the estimation of the efficient cost of wholesale electricity. In considering this problem, the Authority has applied the principle that the efficient cost of wholesale electricity is the amount that would be incurred by an efficient new retailer. This approach leads to a price that would reflect the outcomes in a competitive market.

A necessary condition for a new retailer to enter the market to supply a particular customer class is that its price is no more than the price set by incumbent retailers. As the cost of purchasing wholesale electricity is a key determinant in setting the price, the new retailer would need to ensure that its cost of purchasing wholesale electricity is the lower of the following two:

i. The lowest cost that existing generators are selling wholesale electricity for; or

ii. the cost of wholesale electricity from building its own generation plant.

In making its decision on the amount it is prepared to pay for wholesale electricity, the new entrant would consider the current state of technology and demand. In assessing the current generation fleet, the new entrant would not have regard to the historical costs of the generators that are currently in use. It would know that some of those existing generators used old technology and that the configuration of existing generators may not be optimal, given the current level and shape of demand. It would also know that some generators would no longer be as competitive as they once were, given the introduction of the carbon price. Given that some of the existing generators are no longer competitive, the new generator would know that some of their costs would be written-off and that those generators would not expect to earn a price that exceeded the cost of an efficient new generator.

The method that is commonly used to simulate the costs that an efficient new entrant would incur in contracting for wholesale electricity is the LRMC method. The LRMC method involves disregarding the sunk costs associated with the existing generation mix, then formulating a generation mix that results in the lowest expected cost of meeting demand, given current technology, fuel prices and load shapes. The new entrant would consider this optimal generation mix when deciding on the cost that it would be prepared to incur either in entering into contracts with existing generators or in building its own generation plant. If the new entrant disregarded this information, it would put itself at risk of incurring a cost of wholesale electricity that could be undercut by a competitor.

This competitive dynamic takes place in all well functioning markets, and sometimes leads to existing market participants taking a loss where past investment has resulted in higher costs than those faced by their competitors now. Equally, they would make larger profits where past investment has led to costs that are significantly lower than current competitors' costs. The price of wholesale electricity in a well functioning market would be

expected to converge on the LRMC. With this in mind, regulators in Australia have generally used the LRMC method to either set cost reflective tariffs, or a tariff range. For example, the LRMC method has been used in NSW by IPART in its price determination for electricity retail tariffs. LRMCs have also formed the basis for the determination of efficient wholesale costs in SA and in Tasmania.

Importantly, the application of the LRMC method gives new entrants confidence that retail electricity tariffs that are set by either a regulator or government will be sufficient to enable them to recover the capacity and energy costs associated with their investment. The new entrants will understand that there are risks associated with technological change, unexpected demand changes and other unforeseeable events. However, they will be compensated for these risks by the rate of return that is embodied in the LRMC calculation.

If prices were not set on the basis of LRMC, and if participants in the electricity industry were permitted to recover all of the costs incurred in the past, even if, with the benefit of hindsight, those investments are now considered inefficient, then consumers would end up carrying the risk and paying for it in higher prices. That would not be efficient.

The Authority has found that the generation mix that results from the LRMC method is very sensitive to the assumptions on fuel prices and the rate of return (which reduces the competitiveness of capital intensive generation plant). The Authority's assumptions for gas prices in the Draft Report resulted in a generation mix that was entirely fuelled by gas. Some submissions, particularly the submission by Synergy, were concerned that this was not realistic because of the constraints on gas availability. The PUO also expressed concern that the LRMC calculation did not recognise the importance of coal-fired generation plant for providing security of supply.

In response, the Authority has reconsidered the assumptions that it utilised in the LRMC model. The Authority accepts that a 100 per cent gas generation mix would imply a large increase in domestic gas prices in Western Australia, that is, even if the gas could be sourced. Consequently, the Authority has reconsidered the assumptions that it utilised for fuel input costs in the LRMC. The Authority's revised assumptions take account of the potential pressure for higher coal and gas prices, driven by the levels of demand implied by the LRMC method. The Authority is satisfied that the revised assumptions derived for the LRMC are appropriate and are feasible within the constraints of the Western Australian energy market.

3.4.2 Other issues relating to LRMC

A number of submissions have commented on various input assumptions that were made in the Authority's Draft Report and used to derive the LRMC. The following section deals with the issues that were raised in relation to the input assumptions.

3.4.2.1 Energy security

In its submission in response to the Authority's Draft Report, Synergy commented that the LRMC modelling should account for market realities, including considerations of energy security. Energy security is generally taken to be improved by having a more diverse mix of fuel types and fuel supplies.

The Authority notes that its task is to determine efficient prices, based on current policy settings. The Authority is not aware of any regulatory or market obligation that requires a defined mix of generation plant to operate in the market.

Nevertheless, given the change in the LRMC input assumptions, the optimal LRMC fuel mix is now more diverse than that set out in the Draft Report. The optimal mix now includes a large proportion of coal based plants in each of the four years of the review. The revised LRMC input assumptions driving this change relate to changes in the coal and gas input prices (see the following Sections), in the WACC (see Section 6.5.1) and in the capital cost (see Section 3.6.2).

3.4.2.2 Coal supply terms and availability

The LRMC estimates set out in the Draft Report utilised a coal fuel cost assumption of $2.21 per GJ (2011/12 prices), which was the Authority's estimate of pricing relating to the current contracts for supply to coal fired generators in the south west of the State.

The Authority recognises that an efficient new coal generator may need to negotiate a new contract for coal supplies. In this context, the Authority notes that the new owners of the former Griffin coal fields, Lanco Infratech, have signalled that they are looking to increase prices closer to export netback prices.[23]

A new entrant coal fired generator could therefore expect to pay prices closer to the export netback price. Equally, if an existing coal fired generator could not meet the LRMC electricity price, and chose to on-sell its coal, it is likely that the subsequent coal contract price would approach the export netback price.

On this basis, the Authority considers that the export netback price is the correct coal price to adopt for the purposes of the LRMC calculation. The Authority estimates that the netback price would be around $3.25 per GJ (2011/12 prices).[24] This coal price has been used for the LRMC estimates.

3.4.2.3 Gas supply terms and availability

Synergy, Verve Energy and the PUO all commented on the gas assumptions adopted for the Draft Report LRMC modelling.

First, Synergy was concerned that the gas price adopted in the Draft Report decreased in real terms over the period to 2015/16. Furthermore, Synergy is of the view that any generator committing to a new long term capital investment would require a long term fuel contract, which normally involves fixed prices. Accordingly, Synergy recommended that fixed fuel prices should be used for the review process.

Verve Energy also considered that the delivered gas price assumptions used by Frontier Economics in the Draft Report are lower than the likely market price for long term gas supply contracts in the Western Australian market.

Second, Synergy raised concerns that the LRMC method may not be appropriate if it resulted in a generation mix that was fuelled entirely by gas, because there would not be enough gas available to supply such a generation mix. The PUO also was also concerned about constraints around gas creating a barrier for new entrants.

---

[23] That said, current expectations are that Lanco will honour its existing contracts for electricity generation. See The Australian 2011, 'India's Lanco Infratech ends threat to stop coal supply', August 11.

[24] The international thermal coal price is expected to average around $110 per tonne over the review period, or around $4.00 per GJ (see for example Reuters 2012, Bank of America Merrill Lynch lowers its 2012 thermal coal price forecast, www.reuters.com). The Authority has assumed a transport and port cost of 75 cents per GJ, giving a free on board price of $3.25 per GJ (2011/12 dollars).

As noted above, the Authority has reconsidered this issue. The Authority accepts that a 100 per cent gas mix would not be feasible.

A 100 per cent gas mix of generation plant to meet Synergy's entire load would require a substantial increase in the amount of gas required. The Authority estimates this increase to be around 40 PJ.[25]

This demand for such a large additional amount of gas over the review period would likely have a significant impact on gas prices in the South West. Over the next four years, all domestic gas supply to the South West is fully contracted. This implies that the gas would need to be sourced from some other load in the State. Given that all available domestic gas over the review period is contracted and being used (and recognising that there is only around 10 to 20 PJ flowing to the short term secondary market), the Authority has assumed that the only way to source the additional gas from the South West would be to pay distillate equivalent prices of around $26/GJ. Furthermore, any gas sourced by paying distillate equivalent prices in the North West could not be transported south, as there would be no spare capacity of this scale on the Dampier to Bunbury Natural Gas Pipeline in the short to medium term. The implication is that gas on this scale in the short to medium term is likely to be only available at $26/GJ from within the South West, and even then, the availability of such a large amount of gas is questionable.

The Authority addressed this issue by examining the gas price that would induce coal fired generation to re-enter the mix of generators in the LRMC calculation, even with the higher coal price assumption. The Authority's consultant, Frontier Economics, found that a gas price of $9.28 per GJ (2011/12 dollars) over the review period would be sufficient to allow coal to re-enter the generation mix. The results are very sensitive to this gas price; that is, there is either zero coal entry (at prices of $8.28 per GJ), or else coal reverts to a share of around 65 per cent (at $9.28 per GJ).

The corresponding 35 per cent gas share for the LRMC calculation, with a gas price of $9.28 per GJ, requires around 33 PJ of domestic gas supply. This is well within the existing 50 PJ of gas that is estimated to be available to generate Synergy's load (see footnote 25). Accordingly, the Authority is satisfied that the revised amount of LRMC gas supply would be available.

Furthermore, the Authority considers that it is appropriate to base the LRMC calculation on the assumption that gas is priced at $9.28 per GJ. The Authority considers that it is more appropriate to use $9.28 because $9.28 per GJ is the point at which the fuel mix changes from entirely gas to partly coal. This gas price ensures that there is sufficient gas available.

On this basis, the Authority is satisfied that the gas price and availability utilised for the revised LRMC estimates are consistent with the domestic gas market in Western Australia.

[25] This estimate is derived as follows. Current total gas use for electricity generation on the South West Integrated Network (**SWIN**) is around 80 PJ, of which Synergy's load share is around 50 PJ (derived by pro-rating the total SWIN load of around 19,500 GWh by Synergy's load share of around 12,000 GWh). On the other hand, Frontier Economics estimates that the total domestic gas demand for 100 per cent gas-fired generation would be around 90 PJ. The difference between 90 PJ and 50 PJ is 40 PJ, which provides an estimate of the additional domestic gas requirement to convert the Synergy load to 100 per cent gas fired generation.

3.4.2.4 Emissions intensity

Synergy comment in their submission that the Authority has not taken into account any Scope 2 or Scope 3 emissions incurred by generators that may be passed on to retailers. Synergy's concern is that the estimate of emissions intensity for generators that has been used by Frontier Economics in its LRMC modelling does not account for emissions associated with the upstream production of fuel (gas or coal) used by generators.

However, the Authority notes that the emissions intensity that Frontier Economics has adopted in its LRMC modelling does account for the Scope 3 emissions associated with the upstream production of fuel. The emissions intensity used by Frontier Economics is sourced from AEMO's NTNDP. The NTNDP separately identifies a Scope 2 combustion emission factor and a Scope 3 fugitive emissions factor.[26]

The Authority is therefore satisfied that the emissions intensity used by Frontier Economics, accounts for emissions associated with the upstream production of fuel (gas or coal) used by generators.

3.5 Synergy's Demand Forecasts

A key input into Synergy's wholesale electricity procurement model and the estimation of the LRMC of energy is Synergy's demand forecasts at half hourly intervals. The Authority has conducted its assessment of Synergy's demand forecasts, in order to ensure that Synergy's demand forecasting approach and assumptions are appropriate.

This section summarises Synergy's methodology for forecasting electricity demand, and the Authority's assessment of the methodology. A detailed explanation of Synergy's approach to demand forecasting is contained in Appendix D.

3.5.1 The use of Synergy's total load

In determining the allowance for wholesale electricity costs in the Draft Report the Authority based costs on Synergy's total load shape. This includes both non-contestable customers and contestable customers.

In its submission in response to the Draft Report, Synergy noted that determining the allowance for wholesale electricity costs on the basis of Synergy's total load is likely to lead to a lower estimate of wholesale electricity costs than determining the allowance on the basis of Synergy's non-contestable load. The reason is that Synergy's total load has a flatter profile (and is therefore cheaper to supply) than Synergy's non-contestable load. Synergy suggested that determining the allowance for wholesale electricity costs on the basis of Synergy's total load is therefore in conflict with the Authority's framework in setting regulated tariffs on the basis of the costs that an efficient new retailer could undercut.

[26] ACIL Tasman, *Preparation of energy market modelling data for the Energy White Paper*, Supply assumptions report, 13 September 2010.

The Authority does not agree that determining the allowance for wholesale electricity costs on the basis of Synergy's total load is inconsistent with setting tariffs on the basis of the costs that an efficient new retailer could achieve. In the Authority's view, a new entrant retailer to the SWIS will be likely to compete for both contestable and non-contestable customers (assuming there is full retail contestability). The Authority considers that a new entrant retailer would do this for precisely the reason identified by Synergy: supplying a combination of contestable and non-contestable customers is likely to result in lower wholesale electricity costs than supplying only non-contestable customers.

It may be the case that there is competition to supply contestable customers because these customers have attractive load shapes. However, this is simply the nature of markets. If a new entrant retailer is unable to compete for and win these contestable customers then that retailer is most likely inefficient. By extension, increasing regulated tariffs in order to make entry easier for that retailer is also inefficient.

3.5.2 Synergy's Approach to Demand Forecasting

Total Annual Demand Forecasts

Figure 5 below shows Synergy's historical and forecast energy sales from 2006/07 to 2015/16. Synergy's sales to residential customers were measured at [redacted] GWh in 2010/11, a marginal increase of [redacted] per cent from the 2009/10 level. Sales for residential customers were forecast to increase by [redacted] per cent in 2011/12, followed by a forecast reduction of [redacted] per cent in 2012/13. Synergy's residential sales forecasts remain steady from 2013/14 to 2015/16.

Figure 5 Synergy's Historical and Forecast Energy Sales (GWh) 2006/07 to 2015/16

[redacted]

Source: Synergy

Demand Forecasts for Non-Contestable Customers

Most non-contestable demand is for the residential (A1) and smart meter (SM1) tariff classes (82 per cent of total non-contestable annual sales) and low voltage supply (L1) customers (12 per cent of total non-contestable annual sales) in the small to medium enterprise category. Synergy's forecasts for non-contestable customers are based on assumptions about the growth in customer numbers and consumption per customer (including assumptions about housing growth rates, energy efficiency, energy usage per account, uptake of appliances such as air conditioners, and growth forecasts for photovoltaic systems). A full description of these assumptions is contained in Appendix D. Synergy has made some further qualitative adjustments in A1 demand forecasts to account for the recent upsurge in photovoltaic systems (estimated by Synergy to result in a reduction in non-contestable demand of [redacted] GWh per year by 2014/15, around [redacted] per cent of total non-contestable demand).

Demand Forecasts for Contestable Customers

Synergy's STEP model, which is used to forecast contestable customer demand, contains assumptions for various scenarios of tariff increases (transition to cost reflective prices). These include: customer losses due to competition, customer acquisition, the effectiveness of sales strategies, the timing and extent of Mid West expansion, environmental policy and energy efficiency, state economic growth and international economic conditions (see **Error! Reference source not found.** in Appendix D). The model uses data on actual consumption by contestable customers, metered use, new and lost customers, and consumption growth forecasts by industry group, to forecast consumption volumes for different groups of contestable customers.

3.5.3 Authority Assessment of Synergy's Demand Forecasts

The Authority has examined the approach and the assumptions used by Synergy in its demand forecasting, and the accuracy of Synergy's demand forecasts as compared to actual demand.

Synergy's forecasts for total demand have been very close to actual total demand, with a variation of less than two per cent per annum in the years 2005/06 to 2010/11. However, there were significant variations between actual and forecast demand for individual tariff classes (see Table 4 below). In considering the cases where large variations in demand were observed, the Authority notes that these tariffs relate to extremely small groups of customers, being around 30 customers on the R1 tariff to around 500 on the B1 tariff[27]. Due to the small number of customers on each tariff, these variations between actual and predicted demand do not materially impact on the Authority's overall findings.

Total non-contestable demand in 2010/11 was 7.1 per cent below forecast, and contestable demand was 14.5 per cent above forecast. Synergy has provided explanations for individual variations, including, for example, changes in the assignment of customers to tariff classes; higher than anticipated growth in contestable demand due to delays in the introduction of full retail contestability.

Table 4 Synergy's Forecast Variations as Percentage of Total Electricity Volumes 2005/06 to 2010/11

	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Non-Contestable	-0.3%	0.8%	-2.4%	-1.3%	2.3%	-7.1%
Contestable	-2.0%	2.2%	0.9%	7.4%	-1.7%	14.5%
Total	**-1%**	**1%**	**-1%**	**2%**	**1%**	**1%**

Source: Synergy

Synergy's demand forecasts do not appear unreasonable due to the following:

- The annual load shape (distribution of demand over the year) is based on last year's load shape. This simple approach is likely to be superior to any more sophisticated approach. This is because day to day and hour to hour demand variations are largely driven by changes in weather conditions and cyclical consumption patterns.

[27] R1 tariffs are time-of-use (<50MWh) for non-contestable customers. B1 tariffs are residential water heating tariffs for non-contestable customers.

- The total non-contestable demand forecast takes into account two factors, being growth in households and changes in average household consumption. Growth in households is based on data sourced from a reputable agency (BIS Shrapnel). Changes in average household consumption is estimated taking into account major factors such as the penetration of air-conditioning, energy efficiency trends and photovoltaic (solar panels) take up.

- Contestable demand is forecast based on projections of industry growth, estimates of new customers and expected number of customers switching to other retailers. Much of this information is gained directly from account manager surveys of customers in addition to past observations. This sophisticated 'bottom up' approach to forecasting appears to be reasonable in the face of volatile contestable demand, particularly due to the direct incorporation of customers' intentions.

- In the past, year to year total demand forecast errors have been in the order of less than two per cent and have not been biased toward being consistently positive or negative.

Based on the above, the Authority accepts Synergy's demand forecasts for the review period.

3.6 Wholesale electricity costs

The Authority has adopted two approaches to assessing the efficiency of Synergy's procurement of wholesale electricity. The two approaches involve:

- reviewing Synergy's procurement of wholesale electricity in order to determine the efficiency of Synergy's projected wholesale electricity costs; and

- using the LRMC of wholesale electricity as an indicator of the efficient cost of procuring wholesale electricity.

The Authority's considerations in relation to the two approaches follow in the subsequent sections.

3.6.1 Synergy's procurement of wholesale electricity

Synergy has entered into various bilateral contracts to purchase its wholesale electricity. Most of these contracts were competitively procured, except for the RVC that was originally assigned to Synergy and Verve Energy by the State Government as the Vesting Contract.

Synergy uses two models, '[redacted]' and '[redacted]', to optimise its procurement and dispatch decisions.

- Based on the long-term demand forecast, the [redacted] model (developed by Frontier Economics) optimises procurement decisions over a time horizon of around 25 years. Procurement decisions take place over the longer term (generally past 2014) and are based on existing contractual constraints and generic new plant assumptions.

- Using the short-term demand forecast, the [redacted] model optimises dispatch decisions over a shorter time horizon (5 years) and is based on only contractual constraints. Prices determined by the [redacted] model are input into [redacted] and treated as a contract. Only variable costs are input with fixed costs being considered sunk. Dispatch is summarised monthly.

There are two main questions underlying the Authority's assessment of the efficiency of Synergy's wholesale electricity procurement and dispatch.

- Firstly, has Synergy followed appropriate processes to ensure that its contracts with electricity suppliers enable wholesale electricity purchase costs to be minimised? To answer this question, the Authority appointed a consultant, Frontier Economics, to assess a number of bilateral contracts in Synergy's contract portfolio. These included contracts Synergy entered into to meet its REC liabilities, as well as the processes and business cases applied in negotiating these contracts.

- Secondly, given Synergy's existing contracts and their conditions, has Synergy's methodology for utilising these contracts ensured that electricity purchase costs are minimised? The Authority appointed a consultant, Marsden Jacob Associates (**MJA**), to address this question. The consultant examined Synergy's demand forecasting methodology, and developed a contract dispatch model to estimate Synergy's wholesale energy costs under the optimal dispatch, given the constraints of its existing contracts. This model has enabled the Authority to examine Synergy's efficiency in its purchasing of wholesale electricity (including both capacity and energy), meeting its liabilities under Federal Government renewable energy schemes, and in managing the impact of the expected carbon pricing regime.

3.6.1.1 Have the contracts been efficiently procured?

The Vesting Contract

The original Vesting Contract was introduced in 2006, as part of a broader move to introduce competition into the South West Interconnected System and mitigate the market power of Verve Energy and Synergy. The original vesting contract was an arrangement for the wholesale supply of electricity, including for energy and capacity, from Verve Energy to Synergy. The arrangement was initiated and authorised by the State Government. The objective of the original vesting contract was to gradually reduce the level of wholesale electricity supplied from Verve Energy to Synergy, in order to facilitate entry by private investment in the electricity generation and retail sectors, thus enhancing competition.

In 2010, the State Government established revised terms and conditions in relation to the contractual arrangements between Verve Energy and Synergy. This led to the abolition of the original vesting contract and the implementation of the Replacement Vesting Contract (**RVC**). The most significant change between the original vesting contract and the replacement vesting contract involved the removal of the mechanism by which Synergy must displace a proportion of its electricity supply requirements using an open and competitive tender process. The balancing hedge provided by Verve Energy to Synergy in the original vesting contract has also been removed, leaving Synergy with greater exposure to its operational risks, such as the risk of day ahead forecasting errors.

The Authority recognises that the major aim of the RVC was to "provide greater financial stability to Verve and to save the State $1.5 billion over 10 years". [28] However, the Authority observes that prior to the RVC taking effect in October 2010, Verve Energy's financial results, as reported for the 12 month period ending 30 June 2010, already included a significant net profit, presumably as a result of the increases in electricity retail tariffs since April 2009.

The Authority was able to gain background information on the calculation of quantities and prices in the RVC through a formal information request to Verve Energy under Section 51 of the *Economic Regulation Authority Act 2003*. Verve Energy complied promptly with the request. An analysis of the information provided by Verve Energy indicates that there are several aspects to the RVC that would have been unlikely to occur under a competitive process.

Firstly, the RVC contains pricing elements that are influenced by another contract that Synergy has with Verve Energy (the SP08 contract), rather than the price being reflective of Verve's underlying costs. The RVC includes pricing elements for flexible (non- 'must take') energy[29] which have been designed specifically so that the value to Verve of the SP08 contract is not affected. The Authority concludes that under competitive contracting, new contracts would not be artificially distorted to accommodate an existing contract; to do otherwise would risk not being able to compete with a party that does not have existing contracts with Synergy.

Secondly, a major feature of the RVC is the 'must-take' energy component, which appears to be set at a large volume with a high price, in combination with separated energy and capacity prices. In this context, the RVC is unique amongst Synergy's contracts in having both must-take provisions and separated energy and capacity charges. In previous contracts struck by Synergy in competitive processes, including those won by Verve Energy, generators were guaranteed some return on capital either through must-take energy provisions or separate capacity payments, rather than both.

These provisions, combined with a subsequent slowing in electricity demand growth, have led to higher wholesale energy costs to Synergy:

- At the time the RVC was considered, the must-take energy component of the RVC was not expected to restrict Synergy's flexibility to dispatch its other existing contracts in the most cost-effective manner, despite Synergy already having considerable must-take commitments in its contracts with Verve Energy (SP08 and SP09) and wind energy producers. The Authority understands that Synergy was asked to provide Verve Energy with a forecast of its uncontracted energy (that is, energy not able to be supplied by Synergy's existing contracts at the time). Synergy was not asked to provide any sensitivity analysis around its forecast.

- However, Synergy's demand forecasts for the RVC were proven to be too high and Synergy is now constrained by the RVC to the point where it cannot fully optimise its total contracts portfolio in order to achieve the most efficient outcomes.[30]

[28] Minister Collier Press Release, 21/9/2010.

[29] This is additional energy over and above the compulsory must-take volumes that can be purchased under a contract at Synergy's discretion.

[30] The Authority also notes that Synergy's forecasts for 2012/13 and 2013/14 are lower than the equivalent forecasts in 2010.

In assessing this cost to Synergy, the Authority is mindful that no-one has perfect foresight and that there is a chance that any project procured under Synergy's standard processes could result in a cost to Synergy, when considered in hindsight. However, while the Authority can rely on Synergy's processes when considering contracts procured in competitive tenders, no such comfort is available for the RVC.

With regard to the must-take volumes in the RVC, the Authority considers that it is unusual for Synergy to have committed to the large volume must-take components, which gave it little flexibility if its forecasts were too high, given that Synergy already had substantial must-take commitments in other existing contracts.

It is possible that Synergy's optimal forecast may have contributed to the terms of the RVC and hence adversely affected the efficient dispatch of Synergy's total contracts portfolio.[31] Nevertheless, Synergy's wholesale energy costs appear to be higher. It would be inappropriate to pass on these higher costs to consumers, as to do so would result in inefficiency – to the extent that consumers were not facing efficient electricity prices. The Authority notes that the forecasting risks faced by Synergy are compensated in the rate of return for Synergy.

In conclusion, the Authority is concerned that the outcomes of the RVC have contributed to higher wholesale energy costs for Synergy. If these were passed through, this would impose unjustified costs on consumers, and result in a loss in economic efficiency.

The Authority therefore concludes that Synergy's forecast wholesale energy costs based on its current contracts portfolio are not efficient, and should not be allowed to fully pass through to consumers in any year of the review period. Electricity prices should be based on efficient costs, which are set out below in the section on LRMC costs.

Other Contracts

The Authority sought to review the efficiency of Synergy's processes for entering into third-party contracts for the procurement of wholesale electricity and renewable energy. The Authority appointed a consultant, Frontier Economics, to undertake this review. Frontier Economics was asked to provide economic advice to the Authority in relation to determining the efficiency of Synergy's wholesale procurement processes, utilising a desktop review of the processes that Synergy adopts in undertaking its wholesale procurement and in assessing the offers it receives for the supply of wholesale energy.

Frontier's desktop review of Synergy's third-party contracts considered the extent of alignment between the processes that were followed in entering into contracts and Synergy's documented policies and procedures, including hedging procedures, risk limits and other Board policies. The reasonableness of the strategy to enter into contracts was also addressed in the review, by having regard to Synergy's requirements in the management of its overall hedge portfolio and the information that was available at the time about market conditions in general.

Frontier examined the following contracts as part of its desktop review:

- Investec Collgar;
- VESP08 (Verve Energy);

[31] That is to say, the same generators may still be operating at the same levels. The only change is the price that Synergy pays for that electricity.

- VESP09 (Verve Energy);
- NewGen Neerabup; and
- Griffin Energy Bluewaters.

An evaluation of the business decision to enter into the contracts informed by an ex-post understanding of price outcomes, or other market outcomes, was outside of the scope for Frontier's review.

Frontier's approach was to review documentation provided by Synergy, which included:

- the term sheets for the transactions concerned;
- business cases;
- internal market modelling supporting the business cases;
- probity audits reviewing the procurement processes;
- submissions to the Board of Directors; and
- Ministerial correspondence.

The report by Frontier included information on Synergy's objectives for entering into the contracts that were reviewed, as well as brief descriptions of these contracts. Much of this information is confidential and accordingly, Frontier's report to the Authority on its review of Synergy's third-party contracts has not been publicly released.

Consultant's Assessment

In regard to the efficiency of the competitively procured bilateral contracts, Frontier's review found that Synergy's procurement of these contracts was consistent with Synergy's stated objectives.

Frontier observed that Synergy's procurement process has been sound, as it has always involved a detailed business case that had input from market modelling, an examination of present and forecast market conditions and a risk assessment. The latter includes mitigation measures, benchmarking of contract terms and conditions against comparable contracts and, where appropriate, the advice of independent consultants on matters such as the examination of the whole-of-portfolio financial impacts of entering a new contract.

Synergy has also undertaken an ex-post performance review of each contract from a whole-of-portfolio perspective, which is part of good trading practice. The *Assumptions Book 2011* illustrates that each of these contracts that Synergy has entered into has increased its net profit after tax. By employing this approach, Frontier's view is that the performance of the contracts is likely to have been consistent with Synergy's trading objectives of portfolio optimisation and cost minimisation.

Authority's Assessment of Synergy's Procurement

Based on all of the information received from Synergy, and on the assessment by consultants of the processes used by Synergy to procure its contracts, the Authority has concluded that Synergy's decisions to enter into its wholesale contracts were reasonable decisions at the time. Synergy's documentation demonstrated an understanding of the key risks to the business, the mechanisms to mitigate these risks in its dealings with counterparties and, the market and economic circumstances at the time it entered into the contracts

However, the RVC was not procured under the standard processes used by Synergy. As noted above, the RVC increases Synergy's cost of dispatch because it cannot fully dispatch from its cheapest contracts. In hindsight, the RVC's must-take components have imposed a considerable cost on Synergy and if these were passed through, they would impose a considerable cost on consumers.

3.6.1.2 Is Synergy Using its Existing Contracts Efficiently?

The second aspect of wholesale electricity purchasing efficiency is the consideration of whether Synergy's use of the existing contracts is efficient (i.e., whether Synergy's method of using the current contracts minimises wholesale electricity costs).

The Authority appointed consultant Marsden Jacobs and Associates (**MJA**) to examine this issue. The consultant was asked to develop a model to determine the minimum cost at which Synergy could purchase wholesale electricity to meet demand in each half hour, subject to the constraints of its existing contracts. The consultant's approach and key findings are summarised below.

Consultant's Assessment

To provide an estimate of Synergy's efficient electricity purchasing costs, MJA built a linear programming model. This model determines the optimal dispatch of Synergy's contracts for each half hourly interval; i.e. the combination of Synergy's current energy contracts that would be used in each half hour to meet the required demand for that half hour at the minimum energy purchase cost, subject to the terms and conditions built into each of the contracts.

The model estimated Synergy's efficient procurement costs over the five year period from 2012/13 to 2016/17. Contracts contain both price and volume information (i.e. the price to be paid by Synergy for energy purchased under the contract and the volume of energy available in different periods). Most contracts specify prices in terms of fixed capacity charges (to recover capital costs) and dispatch charges (based on the short-run costs of supplying energy, including unit energy costs, as well as the costs of starting up and shutting down plant). However, some contracts have bundled prices, where it is not possible to differentiate between the costs of capacity, energy and RECs.

In determining the optimal deployment of contracts by Synergy, MJA's model incorporates all contractual information on energy dispatch costs and capacity costs that impact on the decision whether to deploy from a certain contract or not. These contractual costs include the estimated impact of the carbon price that will apply from 2012/13 (allowing the Authority to estimate Synergy's actual wholesale electricity costs both with and without a carbon price). The contractual constraints that are built into the model include:

- minimum and maximum levels of energy that may be extracted from a contract over a given time interval, or over a month;
- specification of whether a contract is to start up or shut down within a given time interval;
- measures to ensure that the total energy supplied is not less than total energy demanded in a given interval; and
- whether a contract is a take-or-pay contract, or has dispatch preference (e.g. wind generation).

Contractual conditions may also vary over the life of a contract. For example, the RVC provides for a new set of monthly minimum and maximum constraints for each month over the 60 month period of the contract.

MJA's model uses Synergy's demand forecasts for contestable and non-contestable customers as an input. As discussed in Section 3.4.1, the Authority has reviewed Synergy's demand forecasts and determined that these are appropriate. The model uses a single point estimate of total demand for each half hourly period, even though actual demand will vary stochastically from forecast demand, due to variations in supply and demand conditions at the time of dispatch. However, solving a linear program for a stochastic demand forecast is not practical, as it is not possible to capture information that may reduce demand uncertainty closer to the time of dispatch, such as short-term weather forecasts, in the model.

The Authority's estimate of Synergy's forecast actual (contract dispatch) costs have increased since the Draft Report, mainly due to better modelling of the must-take restriction in the RVC and gas constraints in the NewGen Kwinana project.

3.6.1.3 Authority's Assessment of Synergy's Contracts

Table 5 below presents the Authority's estimates of Synergy's actual wholesale electricity costs, based on the modelling of the efficient dispatch of Synergy's existing suite of contracts. The Authority has estimated Synergy's actual wholesale electricity costs with a carbon price.

Table 5 Authority's Estimates of Synergy's Wholesale Electricity Costs 2012/13 to 2015/16

[redacted]

Source: ERA Analysis

Note: Includes reserve capacity over and above optimal dispatch requirement. Excludes increase costs due to the carbon tax changing the optimal dispatch mix.

Synergy's total wholesale electricity costs are influenced by the range of contracts on offer and how they are dispatched in response to forecast demand. Synergy's wind costs are the most expensive in terms of raw energy, partly due to additional ancillary service costs.

The RVC is the most expensive of Synergy's traditional energy source contracts, although the Authority has no information of its exact fuel composition. This high cost, both relative to Synergy's suite of existing contracts and to the LRMC (see below), casts doubt over whether this is an efficient contract for Synergy to hold.

3.6.2 LRMC of Wholesale Electricity

This section reports on the second approach to assessing efficient costs. It sets out the results from Frontier Economics' assessment of the efficient LRMC of supply of wholesale electricity. The Authority's rationale for determining Synergy's efficient costs through the LRMC method are set out in Section 3.2 above.

Frontier used its proprietary least-cost optimal investment electricity market model ([redacted]) to determine the LRMC of wholesale electricity to meet the demand from Synergy's customers. The Frontier Economics final report on Synergy's LRMC is available on the Authority website[32].

3.6.2.1 Consultant's Findings

Modelling assumptions

The estimation of the LRMC involves a range of key assumptions with regard to capital costs, variable operating and maintenance costs, fuel prices (gas, coal, distillate), WACC and carbon pricing. These are discussed below.

The Authority engaged Frontier Economics to undertake its LRMC calculation based on the new assumptions.

Capital Cost

Capital costs for different technology types modelled by Frontier Economics have been provided in Table 2 of Frontier's final report. In the Draft report, for OCGT plant, the capital cost sourced from 2011 NTNDP is $875/kW (2011/12 dollar, real), which has been used for modelling of the Base Case and the High Case for all years from 2012/13 to 2015/16.

Verve Energy submitted that, in the modelling, the capital costs attributed to some generation plant to determine the optimal LRMC generation mix in the SWIS by Frontier Economics appear to be significantly underestimated. In Verve's view, this is particularly the case for the open cycle gas turbine (**OCGT**) and closed cycle gas turbine (**CCGT**) plant estimates.

The Authority acknowledges that in the Draft Report the capital cost of the OCGT plant used for the LRMC calculation was well below the equivalent figure (around $1200/kW for a 160 MW OCGT plant, in April 2014 dollars) in the IMO's 2014/15 Maximum Reserve Capacity Price (**MRCP**) calculation. The Authority further acknowledges that the MRCP figure is a comprehensive estimate of the cost to build a 160 MW OCGT generation facility in Western Australia.[33] Consequently, the Authority has revised its estimate of the capital cost of an OCGT plant to be consistent with that adopted for the MRCP estimate. This capital cost is set at $1,138/MW, in 2011/12 dollars) in the modelling for this Final Report.

The capital cost for CCGT plant has been increased in the same proportion to the OCGT plant, from the original $1,215/kW (2011/12 dollar, real) to $1,627/kW for the modelling in the Final Report.

[32] Frontier Economics 2012, *LRMC of Regulated Tariffs – Final Report*, www.erawa.com.au.

[33] Independent Market Operator, *Final Report: Maximum Reserve Capacity Price for the 2014/15 Capacity Year*, http://www.imowa.com.au/f175,1981344/IMO_Final_Report_Max_Reserve_Capacity_Price_2014_15.pdf.

There has been no change to the capital cost for a coal plant.

Fuel Costs

As noted in sections 3.4.2.2 and 3.4.2.3, the Authority considers that the gas and coal price assumptions in the Draft Report were too low. In the Draft Report, a coal fuel cost assumption of $2.21 per GJ (2011/12 prices) was utilised. However, the Authority considers that the export netback price is the correct price to adopt for the purposes of the LRMC calculation. The Authority estimates that this price will be around $3.25 per GJ at 2011/12 prices. Similarly, a gas fuel cost assumption of $8.28 per GJ and falling (2011/12 prices) in the Draft Report has since been revised to $9.28 per GJ.

WACC

A WACC value of 7.8 per cent (pre-tax real) was used in the Base Case and the High Case in Frontier Economics' modelling for the Authority's Draft Report. The Authority considers that an updated WACC, that is consistent with the IMO's MRCP framework, is more appropriate for estimating the LRMC price for this report. As in the case of the OCGT capital cost, the Authority considers this to be the best underpinning for the WACC for the Western Australian electricity generation sector. Hence, the Authority has decided to revise the WACC value from 7.8 per cent (pre-tax real) in the LRMC calculation for the Draft Report to 6.66 per cent. The revised WACC is updated to reflect the latest information from financial markets and the Authority's bond-yield approach for estimating the debt risk premium, which is detailed in Appendix E. The lower WACC in the Final Report offsets much of the price increase from the increase in capital costs.

Plant mix

Verve Energy commented that the adoption of a new entrant methodology has resulted in a material underestimation of LRMC, given that the optimal generation mix determined by this methodology is not achievable, as it assumes only gas generation and does not address black coal and wind generation.

The Authority notes that the plant mix from the modelling is an optimal economic outcome based on the assumptions. Due to the carbon pricing impact and the relativity between coal and gas fuel costs, it is possible that investment in coal fired plant will become less competitive in the future. There are other policy drivers for renewable energy generation entering into the market. However, this is considered beyond the scope of this modelling exercise.

Consultant's findings

Using the base case assumptions, Frontier estimated that the carbon-inclusive efficient cost for Synergy's total load was $112.32 per MWh for 2012/13 (real, in 2011/12 dollars).

3.6.2.2 Authority's assessment of wholesale electricity costs

The Authority has used the LRMC for Synergy's total load as the efficient cost for wholesale electricity, rather than the cost of supplying each customer class. This is because aggregating load that peaks at different times, leads to a lower system wide peak, as opposed to the sum of individual peaks, which would add up to be higher than the system wide peak. As Synergy's cost relates to the total load, the efficient cost of wholesale electricity cost should relate to this total load, as opposed to the sum of individual loads.

The Western Australian electricity market separates capacity and energy to ensure sufficient capacity for large spikes in demand or unforseen plant shutdowns. Any cost estimate of wholesale electricity cost must account for capacity payments as required by the IMO.

The Authority has adjusted the LRMC to account for the additional capacity cost that a new entrant would incur under the WEM context. Frontier's LRMC modelling approach includes a 15 per cent reserve capacity margin over the forecast peak supply. However, the IMO's forecast methodology sets a higher capacity requirement which is allocated to retailers.

The Authority acknowledges that Synergy cannot avoid the costs impost due to the higher capacity requirement, and any efficient retailer in WA will have to incur this cost. As such, the Authority recommends that the LRMC energy cost should be adjusted to incorporate the cost associated with the additional capacity requirement in WA's wholesale market.

As in the Draft Report, the Authority has allowed for a higher reserve capacity requirement than adopted for in Frontier Economics' modelling and so has included an allowance for this cost to Synergy in its final estimate. Also, as in the Draft Report, the Authority has allowed an additional fixed network connection charge equivalent to $2.1 million[34] (in 2010/11 prices) for a 160 MW OCGT facility.

In doing so, the Authority has accepted Synergy's capacity pricing mechanism, where capacity is priced as follows:

- if a specific capacity cost is specified in the contract, then capacity is valued at this price;
- if no specific capacity price is specified in the contract, then the procured capacity is priced at the IMO capacity price at the date that the contract was signed; and
- for estimated IMO purchases, capacity is priced at Synergy's forecast of the IMO capacity price.

The Authority has used the adjusted LRMC in its analysis, as set out in Table 6.

As pointed out by Synergy and Verve Energy in their submissions on the Authority's Draft Report, the Authority notes that these LRMC results do not include the costs of complying with the RET. Whilst an LRMC modelling approach can be used to estimate the LRMC of complying with the RET, the 'stand alone' LRMC modelling undertaken by Frontier Economics does not include a requirement to meet a Renewable Energy Target (**RET**) and, therefore, the resulting LRMC does not include any cost of meeting a RET. This is consistent with the framework adopted by the Authority under which the cost of complying with the RET is accounted for separately (as discussed in Section 3.6.4). Incorporating the cost of meeting the RET within the 'stand alone' LRMC would result in double-counting of these costs.

[34] http://www.imowa.com.au/f175,1981352/MRCP_Calculation_Spreadsheet_2014_2015_-_final_v2.0.xls .

Table 6 Adjusted LRMC Accounting for Additional Capacity Required by the IMO 2012/13 to 2015/16

$/MWh, nominal, sent out	2012/13	2013/14	2014/15	2015/16
Wholesale electricity cost (excluding carbon and RECS)	[redacted]	[redacted]	117.17	122.06

Source: ERA Analysis
Note: Figures must be adjusted for line losses for conversion to consumer prices. The estimates exclude changes in costs due to the carbon tax changing the optimal dispatch mix.

Synergy's actual wholesale cost (Table 5) is higher than the LRMC cost (Table 6). Whereas the LRMC is calculated with the benefit of better information and technology, the wholesale contract negotiations are based on past investment and other factors, such as the requirement to sign the RVC with must-take provisions.

3.6.3 Costs of Carbon Pricing

The current generation in the SWIS consists of a mix of coal, gas and renewable sources, with an average carbon intensity of approximately 0.78 tCO2/MWh for Synergy's estimated dispatch in 2012/13. The Authority considers that this is sufficient to cover Synergy's direct and indirect[35] increases in costs due to the carbon tax. This is because several of Synergy's contracts have the respective carbon intensity pass-through limited, and because Synergy has made sufficient allowance for direct and indirect carbon costs in its assumptions regarding its unhedged contracts.

3.6.3.1 Consultant's assessment

The impact of carbon price on Synergy's contract dispatch is calculated slightly differently to the LRMC. For Synergy's contract dispatch, the Authority has calculated Synergy's estimated carbon tax liability, as this figure is of direct relevance to government.

The full impact of the introduction of the carbon price on the LRMC is appropriately determined by running two scenarios; without the carbon price and with carbon price. The incremental difference between these two scenarios reflects the full impact of carbon price. Under the carbon tax, the LRMC will contain a slightly less carbon-intensive generation mix than will the LRMC without the carbon tax. As such, pre-existing generators will not be able to pass their entire carbon tax liability on to consumers. This is discussed further in Section 3.6.3.2 below. The consultant's estimate of the proportion of the carbon tax able to be passed on to consumers by an average pre-existing LRMC generator is shown in Table 7 below.

[35] Direct costs are those associated with emissions from the generation of electricity by Synergy's suppliers. Indirect emissions arise through emissions further up the production chain, such as costs from the emissions resulting from natural gas extraction and transport.

Table 7 Carbon Impact on LRMC and Contract Dispatch Prices 2012/13 to 2015/16, Nominal

	2012/13	2013/14	2014/15	2015/16
LRMC				
Proportion of carbon-tax passed on to consumers (average generator)	73.33%	73.19%	72.90%	72.40%
Total Carbon Tax Impact $/MWh	16.95	17.76	18.61	21.10
Total Carbon Tax Impact $m (total load)	202.59	213.39	225.99	258.15
Synergy' s Contract Dispatch				
Total Carbon Tax Impact $/MWh	[redacted]	[redacted]	[redacted]	[redacted]
Total Carbon Tax Impact $m (total load)	[redacted]	[redacted]	[redacted]	[redacted]

Source: ERA Analysis

3.6.3.2 Authority's Assessment

The difference between the wholesale electricity cost that Synergy will incur due to its current contracts, and the LRMC, is partly explained by the difference in the carbon cost.

The extent of the carbon cost that a generator will face depends on, the carbon intensity of the generator, amongst other things. For example, in its calculation of LRMC, Frontier Economics has assumed a carbon intensity of a coal based generator of about 0.84, whereas the carbon intensity assumed for an OCGT is 0.43.

However, the full cost of carbon that is imposed on a generator is not necessarily passed on to consumers in an efficient market. The amount of carbon cost that is passed on to consumers in an efficient market is the cost that applies to the marginal generator (that is, the last generator that is called upon to meet demand at any given time). The Commonwealth Government has noted that:[36]

> How much of the carbon cost individual generators can recoup depends on how much electricity prices increase in each market. The emission intensity of the marginal generator at different times through the day and over the year largely determines this. If the marginal generator is less emission intensive than a particular generator, this compresses the margins of that generator, reducing its profits.

Therefore, for example, a coal based generator cannot always pass through the full carbon cost it incurs because, in a competitive environment, it may be under-priced by a less carbon intensive generator, as it is the short-run marginal cost that determines dispatch. As such, highly carbon intensive generators will incur some losses in their profitability, leading to lower returns for their shareholders. The level of decrease in their profitability would depend on a range of factors, including any government-funded assistance.

[36] Commonwealth Treasury 2012, *Strong Growth, Low Pollution: Modelling a Carbon Price*, www.treasury.gov.au.

Generators, including Verve Energy, recognise that this is the case. In one of the submissions to the Federal Government, the National Generators Forum stated that:

> Based on updated modelling undertaken separately by Macquarie Generation, Delta Electricity, CS Energy, Stanwell Corporation and Verve Energy the total combined reduction in profit to these businesses under a carbon price is $4 billion to $5.5 billion (**NPV**).

The Authority recommends the LRMC carbon pass-through in Table 7 above. The Authority notes that the implementation of the carbon price introduces a risk for investors. Some of the loss in profitability will be compensated for by the Federal Government's assistance to many of the coal fired generators. However, this compensation is largely provided to brown coal generators, mainly in Victoria. Western Australian generators have not received any Federal Government assistance.

The Authority also notes that Verve Energy has earned a significant return in the last financial year. The Authority notes that Verve Energy achieved a rate of return of 14.8 per cent in 2010/11[37], and therefore any losses arising from its inability to fully pass through its carbon tax liability should not impact on its financial viability.

3.6.4 Procurement of RECs and LGCs

In addition to the procurement of wholesale electricity, retailers in the SWIS are also required to comply with renewable energy policy obligations.

On 24 June 2010, the Commonwealth Government passed legislation (the *Renewable Energy (Electricity) Amendment Bill 2010*), making significant changes to the expanded Renewable Energy Target (**RET**) scheme in order to address the oversupply imbalance in RECs which retailers are required to purchase. From 1 January 2011, the RET was split into two schemes, being the Large-Scale Renewable Target (**LRET**) and the Small-Scale Renewable Energy Schemes (**SRES**). As a result of this change, two new types of REC were created: Large-Scale Generation Certificates (**LGCs**) and Small-Scale Technology Certificates (**STCs**). Under the change, all RECs will be recognised as LRECs.

The LRET effectively continues Synergy's pre-existing obligations under the RET. Synergy must surrender LGCs to meet its obligation. Additionally, Synergy must surrender LGCs in relation to the sale of its accredited GreenPower products.[38]

The SRES is a new scheme introduced to accommodate the certificates produced by small-scale renewable installations, largely consisting of residential photovoltaic installations. Synergy must also surrender STCs to meet its obligation.

3.6.4.1 Synergy's Approach to REC Procurement and Forecasting

LRET Liability

From 2006 to 2010, Synergy met its REC liability from the following sources:

[37] http://www.parliament.wa.gov.au/Parliament/commit.nsf/(Evidence+Lookup+by+Com+ID)/0684114D87DA0C3148257936001DC0FF/$file/ef.aar10.111021.tro.001.Verve+Energy.pdf

[38] For the sale of each MWh of GreenPower, Synergy is required to surrender one LGC.

- purchase agreements with Verve Energy for RECs created from the Albany wind farm and the biomass firing facility at Muja Power Station (Muja biomass). The contract for RECs from Muja biomass has now ended;

- purchase agreements for RECs produced from the Emu Downs wind farm;

- purchase agreements for RECs produced from the Henderson Renewable Energy Facility;

- a purchase agreement for RECs produced from the Mount Barker Community Wind Farm; and

- market purchases and market based short term contracts.

In response to the relatively low REC/LGC prices in late 2010 and early 2011, Synergy made a strategic decision to purchase LGCs to cover liabilities in future periods. These were purchased by using a combination of spot and forward contracts and will cover Synergy's forecast LRET exposure up until 2016. Synergy's forecast LRET exposure is shown in Table 8 below.

Table 8 Synergy's Forecast LREC Expenses ($/LGC)

2012	2013	2014	2015	2016
[redacted]				

Source: Synergy

SRES Liability

SRES liability has only existed from 1 January 2011. SRES liabilities must be settled quarterly. Synergy has met its liability by purchasing from the market at prices less than the clearinghouse price of $40/STC, and is continuing to do so.

Synergy does not intend to cover its SRES liability by entering long term bilateral contracts. Synergy's exposure is managed by purchasing from the market and entering into short term bilateral contracts of less than 12 months.

3.6.4.2 Authority Assessment of Synergy's REC Forecasting and Procurement

The Authority has examined the assumptions used by Synergy in its REC procurement by benchmarking Synergy's forecast costs against those published in other jurisdictions.

In considering Synergy's LREC procurement, the Authority notes that Synergy's forecast LGC price is derived from its existing bilateral contracts. As these LGC prices have been locked in, they will provide a hedge against any future volatility in the LREC market. The Authority notes that the contracted LGC prices are around 50 per cent of the LRET penalty price.

In relation to STC procurement forecasts, Synergy assumes a forecast price of $40/STC, being the fixed clearinghouse price. Given the level of political uncertainty around photovoltaic installations in Western Australia and with regard to Federal policy, and in light of the potential volatility of the new SRES market, the Authority finds this assumption to be reasonable. While the Authority has made some slight adjustments to Synergy's costs in terms of the cost of holding stocks, in general, it finds Synergy's REC procurement efficient.

The Authority has concluded that Synergy's procurement of RECs, including generation commitments that generate RECs for Synergy, has been efficient. Accordingly, the Authority has accepted Synergy's forecast of REC costs.

3.6.4.3 Authority's Conclusion on Wholesale Energy Procurement

The Authority concludes that Synergy has generally procured wholesale electricity efficiently. Furthermore, the Authority also concludes that Synergy's dispatch of its available suite of supply contracts is efficient, taking account of the uncertainty that Synergy faces.

The exception to this conclusion relates to the electricity supplied under the RVC. This contract was negotiated in conjunction with the government, and has features that the Authority considers are inefficient. The RVC also has constrained Synergy's dispatch of electricity, such that it is not able to utilise its least cost electricity supply.

On this basis, the Authority considers that the LRMC of wholesale electricity is a more appropriate basis for determining efficient wholesale electricity purchase costs.

In the Draft Report the Authority allowed two years of actual costs, but given its concerns with regard to the efficiency of the RVC, the Authority has decided to use LRMC for all four years in this Final Report.

The Authority's estimate of the efficient wholesale cost of electricity is shown in Table 9 below.

Table 9 Efficient Wholesale Electricity Cost ($/MWh, nominal) 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Wholesale electricity cost (incl. Capacity)	117.10	116.81	117.17	122.06
Carbon	16.95	17.76	18.61	21.10
RECs	10.81	7.76	7.79	8.57
Total	**144.87**	**142.34**	**143.57**	**151.72**

Source: ERA Analysis

3.7 Final Recommendations

1. The Authority considers Synergy's demand forecasting approach and assumptions to be appropriate and has accepted Synergy's demand forecasts for the pricing period.

2. The Authority considers Synergy's methodology and estimates for dispatching energy to be efficient.

3. The Authority recommends the use of LRMC for calculating the efficient wholesale electricity cost.

4. The Authority does not consider the pass-through of Synergy's actual cost of carbon to customers to be efficient. The Authority regards the carbon cost built into the LRMC calculation to be consistent with carbon cost that would be expected in a competitive market.

5. The Authority considers Synergy's procurement of RECs to be efficient.

4 Retail Operating Costs

4.1 Background

Synergy's remaining controllable costs are those associated with its retail activities. Retail operating costs include:

- billing and revenue collection costs;
- call centre costs;
- customer information costs;
- corporate overheads;
- energy trading costs;
- regulatory compliance costs; and
- marketing costs.

The costs incurred in these activities are driven by the level of service that Synergy is required to provide. The minimum service standards that apply to Synergy's retail services are specified as part of its licence conditions and relevant legislation, and Synergy's performance against these service standards is monitored by the Authority. It is important that Synergy is provided with sufficient revenue for the efficient provision of its service level obligations.

Retail operating costs will vary depending on whether customers are non-contestable (tariff categories A1, SmartPower, B1, C1, D1, K1, L1, R1, W1 and Z1) or contestable (L3, M1, R3, S1 and T1 tariff categories). In the case of contestable customers, there may be additional costs associated with customer service, or transferring customers to alternative tariffs.

Synergy's retail operating costs are small relative to the costs of energy procurement and network charges (around $120 million in 2010/11, compared to total costs of $2,500 million for that period). Synergy's capital expenditure is also low (around $10.6 million in 2010/11). Most of this capital expenditure is related to Synergy's implementation of a new billing system, to replace 50 legacy systems inherited upon disaggregation from the former Western Power Corporation. The new system covers electricity and gas transactions, billing, customer relationship management and e-business. A key consideration is the extent to which the new billing system will lower future costs of customer servicing.

The Authority engaged a consultant (Frontier Economics) to examine the efficiency of Synergy's operating expenditure. The consultant used information on the unit costs of other comparable electricity retailers as a benchmark to estimate Synergy's relative operating efficiency.

4.2 Draft Report

The Authority made a number of recommendations in relation to retail operating costs in the Draft Report:

- Retail operating costs in the first two years; 2012/13 and 2013/14, should be based on Synergy's forecast actual retail operating costs, followed by approximately $81 per customer (in 2011/12 dollars) for 2014/15 and 2015/16.

- Retail operating costs should be escalated by 3.58 per cent over the review period.
- Depreciation should be separately accounted for – an average annual depreciation cost of $14.10 per customer (in 2011/12 dollars) should be applied.

4.3 Public Submissions

The public submissions on the Draft Report included the following comments relating to retail operating costs.

Synergy

Synergy broadly supports the approach adopted by the Authority in determining the allowable retail operating costs to be recovered from tariff customers, but considers that a separate and additional cost allowance for the acquisition and retention of contestable customers be included in the allowable costs to be recovered.

Synergy also indicates that a two year glide path for achieving the benchmark costs would be appropriate.

Public Utilities Office (Department of Finance)

The PUO suggests that in bidding for different customer groups the market will recognise, and price, the differing underlying costs for each tariff class.

PUO indicates that, consistent with the Inquiry's Terms of Reference, the Authority's tariff methodology should recognise the differing underlying costs of each tariff class.

Alinta

Alinta accepts that the methodology in the immediate term is appropriate, but indicates that the methodology should be revisited in future reviews and that the Authority should comment upon the suitability of the ROC methodology going forward. Alinta would like to see the level of the ROC transition to a benchmark level so as to incentivise retailers to act as efficient enterprises.

Horizon Power

Horizon Power indicates that where there are differences in the costs associated with retailing to the various tariff classes, it would be appropriate to have a customised retail margin or cost reflective level of unit retail operating cost.

Horizon considers that two years may not provide a sufficiently long timeframe to implement efficiencies so as to meet benchmark retail unit costs.

Horizon supported the Authority’s separate consideration of both labour and non-labour costs in the escalation factor applied to retail operating costs.

Perth Energy

Perth Energy indicates that the level of retail operating costs is dependent on the efficiency with which an organisation is able to deliver the required level of service. Perth Energy considers that:

- the allowance for depreciation costs is higher than for comparable retailers;
- costs to service should be determined separately for the different segments of customers.

4.4 Service Standards

Synergy's main reporting requirement is undertaken as part of its electricity retail licence obligations.[39] Synergy reports to the Authority against performance standards covering billing, payment arrangements, responding to customer queries and complaints and compensating customers for breaches of particular service standards.

Each year the Authority publishes its report on the performance of electricity retailers, the latest version of which is the 2010/11 report. The report covers four areas (affordability, access, customer service, and compensation payments). A copy of the report is available on the Authority's website[40].

Synergy also publishes information relating to its performance in its Annual Report and Quarterly Reports.

The service standards that Synergy is required to report as part of its licence conditions are similar to those reporting requirements in other Australian jurisdictions. Synergy's historical service level performance is comparable and at a level consistent with retailers in other jurisdictions.

It is outside the terms of reference for this inquiry as to whether alternative minimum service standards should be set for Synergy, or performance measures altered. This would require amendments to Synergy's licence conditions, as well as consultation with customers (for example, as to their willingness to pay for any improvements in service standards that would require additional expenditure, or willingness to accept lower standards for a reduced price). The review of service standards is incorporated into the Electricity Code of Conduct Review, which is undertaken periodically.

However, Synergy's service standards set the framework for determining the level of efficient costs that are required to provide sufficient revenue for Synergy to meet its licence obligations.

4.5 Synergy's Estimates of its Retail Operating Costs

Total Electricity Retail Operating Costs

Synergy provided the Authority with estimates of its retail operating costs for 2010/11 and its forecasts for the period 2011/12 to 2015/16[41] as shown in Table 10 below:

[39] The Authority issued Synergy with Electricity Retail Licence ERL1, which commenced on 30 March 2006.

[40] www.erawa.com.au

Table 10 Synergy's Actual and Forecast Operating Costs ($m) 2010/11 to 2015/16

	Actual		Forecast			
Customer Class	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Total electricity operating costs* ($m)	[redacted]	[redacted]	109.9	113.5	118.1	121.7

Source: Synergy

Note: Operating costs exclude depreciation, amortisation, interest, nomination fees and operating costs associated with gas sales activities, escalated as per Synergy's expected CPI.

Synergy reported that its forecast increases in operating costs were based on the following explanatory factors:

- an expected increase in the costs of dealing with customer complaints, due to tariff increases, and additional Ombudsman-related compliance costs;
- the implementation of new products and services required by government;
- increasing implementation costs associated with the new billing system;
- costs associated with strategic projects and business transformation; and
- higher IT costs arising from the separation of IT systems from Western Power.

To estimate the costs associated with different types of customers, Synergy allocated costs that could be directly attributed to particular customer categories to those customers, while costs that were common to all customers were allocated on the basis of the number of bill accounts.

Non-Contestable Customers

Synergy estimated that, for non-contestable customers, retail operating costs in 2012/13 would be around [redacted] for an average residential customer and [redacted] for an average small to medium enterprise (**SME**) customer (in 2010/11 dollars).

Contestable Customers

Synergy's estimates of its retail operating costs for contestable customers in 2010/11 and forecasts for 2012/13 are presented in Table 11 below. As in the case of non-contestable customers, Synergy expects retail operating costs for contestable customers to increase due to increasing costs of labour, regulatory compliance, and IT and telecommunications.

Table 11 Synergy's Estimated Retail Costs for Contestable Customers in 2010/11 and 2012/13

[redacted]

Source: Synergy

4.6 Synergy's Capital Expenditure

Information on Synergy's capital works programme is included in the annual Budget Papers. A summary of Synergy's cumulative budgeted capital programme per year compared to the cumulative actual expenditure is shown in Figure 6 below.

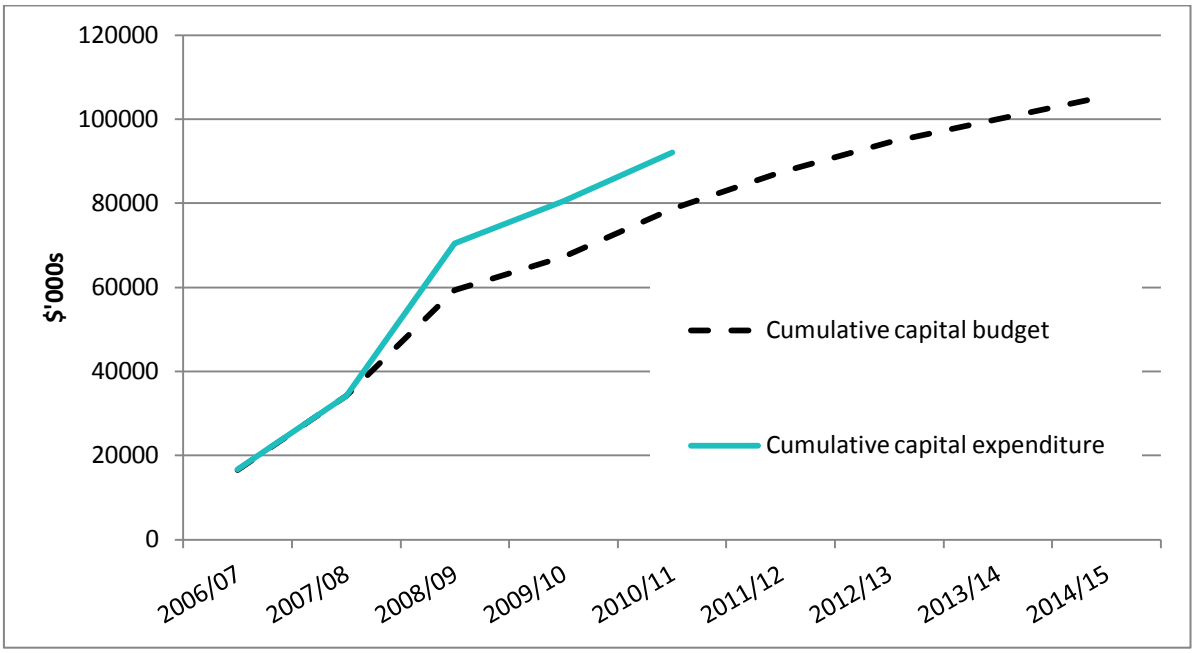
This shows the increase in actual capital expenditure over and above the budgeted amount. By the end of 2009/10, the cumulative capital overspend (compared to the budget) was $13.4 million, as illustrated in Figure 6 below. This partly results from problems encountered during the implementation of the billing system, which has increased budgeted and actual costs from original estimates.

Looking at the information for the customer information and billing system in isolation, in 2006/07, the total budgeted cost was $15.5 million[42] and by 2010/11 the total budgeted cost was estimated at $48.8 million,[43] an increase of over 200 per cent. Actual expenditure on the billing system was $6.7 million above budget at 2010/11. The Authority recognises that capital expenditure for the period from 2007 to 2011 has been impacted both by Synergy's separation from the former Western Power Corporation, and by the implementation of the billing system. Consequently, the level of historical capital expenditure does not necessarily indicate a need for above budget capital expenditure in the future.

[42] Department of Treasury and Finance (2005), 2006/07 Budget Paper No. 2 – Volume 3, p 925.

[43] Department of Treasury and Finance (2010), 2011/12 Budget Paper No. 2 – Volume 2, p 616.

Figure 6 Synergy's Total Cumulative Budgeted and Actual Expenditure for its Total Asset Investment Programme ($'000s) 2006/07 to 2014/15



Source: Department of Treasury and Finance Budget Papers 2006/07 to 2011/12 and ERA Analysis

4.7 Consultant Assessment

4.7.1 Consultant's Approach

The key focus of Frontier's analysis was on the benchmarking of Synergy's per-customer operating costs for different customer classes with those of other electricity retailers. Frontier drew upon 27 determinations by Australian regulators on retail operating costs. In comparing these costs, Frontier took into account a range of factors.[44]

- Some regulators allow for additional retail operating costs to cover customer acquisition and retention. However, these costs are not relevant to Western Australian non-contestable customers, and were deducted for the purposes of benchmarking against Synergy.
- Retailers in other states where FRC has been introduced incur additional costs associated with updating retail systems to make them compatible with a competitive market. These costs are likely to overstate retail operating costs in Western Australia, where there is limited contestability.
- Where depreciation costs were explicitly included in retail costs, these were deducted for comparison with Synergy. For example, the average cost of depreciation for NSW retailers in IPART's 2007 decision was $8-$9 per customer.
- The relative size of the retailers (and the potential for larger retailers to achieve efficiencies due to economies of scale) was considered. However, Frontier considered that Synergy would be able to achieve the same economies of scale as other retailers. With around one million small retail customers, Synergy is comparable in size with standard retailers in NSW, and larger than many other retailers. Further, the average cost curve for retail activities is quite flat over a

[44] Frontier's report is available on the Authority's website at www.erawa.com.

wide range of customer numbers, with new entrants in a number of jurisdictions achieving operating costs similar to those of larger incumbent retailers.

- Economies of scope were also considered (e.g. where retailers can offer dual fuels). However, Frontier concluded that such economies were not relevant to Synergy, as it is subject to a gas market moratorium and cannot supply gas to customers that use less than 0.18 TJ of gas until electricity FRC is introduced.[45] Other regulatory decisions indicated that, in any case, economies of scope are unlikely to be substantial.
- Another issue was whether labour costs in Western Australia were comparable with those in other States. Frontier found that the rate of increase in labour costs in Western Australia was only slightly faster than that in other states (less than 1 per cent per annum difference over the period to 2011), and that the use of benchmarks from other states remained appropriate.

Data on the costs to serve contestable customers are more difficult to benchmark, due to lack of any publicly available data. In making recommendations on retail operating costs for contestable customers, Frontier therefore examined Synergy's assumptions and forecasts, as well as estimates of new entrant retail operating costs that were provided by Synergy as part the Office of Energy's Energy Market Review in 2007/08.

4.7.2 Consultant Findings

Frontier noted that the external factors cited by Synergy as cost drivers for its operating cost forecasts (customer complaints driven by tariff increases; new products and services implemented at the request of government) have been common to retailers in other jurisdictions. Frontier also noted that the additional costs of business transformation cited by Synergy as contributing to higher retail costs for contestable customers could be assessed against the retail costs determined by the Queensland Competition Authority in 2007, during a time of change in the Queensland retail energy market ($77 per customer in 2010/11 dollars). Another suitable comparator was Origin Energy, with a cost to serve of $66 per customer in 2009 (2010/11 dollars).

Non-Contestable Customers

Frontier concluded that $78 per customer per annum in 2012/13 (in 2010/11 dollars) was a reasonable estimate of Synergy's efficient retail costs for non-contestable customers.[46] This estimate is consistent with recent retail operating cost benchmarks in other jurisdictions (once adjusted for the factors noted in the previous section). Further, this estimate was within the range of all the benchmarks considered, and was comparable with the regulatory decisions that were most relevant to Synergy and with Synergy's own cost estimates. Frontier noted that large efficient retailers have been shown to achieve costs lower than $78 per customer.

Frontier recommended against adjusting operating costs to reflect changes in efficiency over the review period, concluding that there is limited opportunity to change the relevant technologies over the regulatory period.

[45] Gas use of 0.18TJ per annum involves the same energy value as electricity use of 50 MWh per annum. The average household uses about 0.018 TJ per annum of gas, and about 6.2 MWh per annum of electricity.

[46] The Authority estimated Synergy's forecast retail cost for the same period to be $89 per annum (nominal) for A1 customers in 2011/12. The Authority adjusted Synergy's forecast estimates to ensure consistent customer numbers in this review.

On the other hand, Frontier did consider that operating costs should be escalated to reflect changes in input costs. Frontier recommended that the escalation should be based on changes in labour costs – noting that changes in labour costs have been estimated by CRA International to make up around 60 per cent of retail operating costs, and that Synergy has projected that labour costs will account for 40 per cent of total operating costs over the regulatory period.[47] In line with this, Frontier recommended that the retail operating cost allowance be adjusted each year by the labour price index for total hourly pay excluding bonuses in Western Australia.

Contestable Customers

Frontier noted that, unlike costs for non-contestable customers, it is not possible to benchmark operating costs for contestable customers. This is because while the operating costs for non-contestable customers are transparently reported by regulators of various jurisdictions, prices for medium to large businesses (contestable customers) tend not to be regulated. As a result, there is very little reliable data that is publicly available to benchmark against.

Frontier has, therefore, focussed its effort on assessing Synergy's actual and forecast cost for these customers. However, Frontier was unable to verify Synergy's operating cost forecasts for contestable customers, due to inconsistent data on projected customer numbers and the methodology of allocating costs to customers. Frontier therefore recommended that retail operating costs for contestable customers be estimated on the basis of Synergy's assumptions on new entrant retail operating costs, provided to Frontier as part of the Office of Energy's 2007/08 Electricity Retail Market Review. This approach results in estimates (in 2010/11 dollars) of:

- $794 per customer for L3, R3 and M1 tariffs in 2012/13, in line with Synergy's estimates of the efficient new entrant cost for the R3 tariff; and
- $2,267 per customer for S1 and T1 tariffs in 2012/13, in line with Synergy's estimates of the efficient new entrant cost for these tariffs.

4.8 Authority Assessment

The primary principle when determining appropriate revenue to cover retail operating costs is to assess the costs that would be incurred by an efficient retailer. Competitive markets encourage efficiency, as retailers compete for contestable customers in terms of better prices and service quality, so benchmarking against retailers in such markets provides the best guide to efficient retail operating costs.

4.8.1 Benchmarking retail operating costs

It is important when benchmarking against other retailers to ensure that benchmarks are comparable. Some regulatory allowances for retail operating costs have included depreciation costs. However, the Authority has made a separate allowance for depreciation (see Section 4.8.5), so depreciation is excluded from retail operating costs. Benchmarking comparisons have excluded depreciation from comparable retailers' operating costs for consistency where possible.

[47] Frontier Economics 2012, *Retail Operating Costs: A Report Prepared for the Economic Regulatlion Authority of Western Australia*, www.erawa.com, p. 31.

The evaluation in the Draft Report of an allowance for retail operating costs for smaller customers consuming less than 160 MWh per annum accounted for a range of data:

- The benchmarking assessment carried out by Frontier covers a wide range of regulatory decisions on retail operating costs in competitive retail markets across Australia. The retail operating cost estimate of $78 per customer (in 2010/11 dollars) recommended by Frontier is an average across the most relevant of these regulatory decisions, some of which may include costs associated with full retail contestability (**FRC**), and depreciation, and others which exclude these costs. This estimate will therefore approximate, but not underestimate, the efficient retail costs for customers consuming less than 160 MWh per annum.
- Converting Frontier's estimate to 2011/12 dollars gives an estimate of approximately $81 per customer, on average, for all regulated customers consuming less than 160 MWh per annum.
- The Authority acknowledges that customers consuming greater than 50 MWh per annum (such as tariff classes L3, R3 and M1) are likely to have higher operating costs due to dedicated resources required in managing these customers. However, since the benchmarking data from other jurisdictions does not differentiate between larger and smaller customers, the average benchmarking cost is applied across all customers consuming less than 160 MWh per annum to derive the retail operating cost allowance.

In setting the revenue allowance for retail operating costs for the Draft Report, the Authority was of the view that approximately $81 in 2012/13 (in 2011 /12 dollars) would be an efficient cost per customer – when averaged across all customers consuming less than 160 MWh per annum.

Synergy indicates that it broadly supports the benchmark approach to setting retail operating costs adopted by the Authority.

Alinta considers that the retail operating cost allowance estimated in the Draft Report is conservative, and that the methodology should be reviewed – with a view to transitioning to a benchmark level. As a corollary, Alinta considers the 'base' retail operating cost of approximately $81 per customer per annum in 2012/13 to be at the lower end of the range of the benchmarks.

However, the Authority considers that the base retail operating cost allowance of approximately $81 (in 2011 /12 dollars) is consistent with recent relevant benchmarks from other jurisdictions for electricity retailers operating in markets with similar scale to the Western Australian market. These include:[48]

- the Independent Pricing and Regulatory Tribunal's estimate in 2010 for around $70 for a New South Wales electricity retailer (in 2011/12 dollars – once FRC costs estimated by Frontier at around $10 per customer are removed);[49]
- the Queensland Competition Authority estimate in 2011 for around $77 for Queensland (in 2011/12 dollars – once FRC costs of around $10 per customer are removed);

[48] Frontier Economics 2012, *Retail Operating Costs: A Report Prepared for the Economic Regulatlion Authority of Western Australia*, www.erawa.com, p. 28.

[49] Ibid.

- the Essential Services Commission of South Australia estimate in 2010 of around $79 for South Australia (in 2011/12 dollars – once customer acquisition and retention costs are removed).

The higher benchmarks in the Frontier range tend to be of less relevance to Western Australia, as these generally are for retailers in markets of a smaller scale.[50]

The Authority is therefore satisfied that the average retail operating cost allowance for small to medium customers, of approximately $81 (in 2011/12 dollars), is a reasonable benchmark that reflects efficient costs.[51]

For the larger S1 and T1 tariff customers, the Authority accepts Frontier's recommended retail operating cost of $2,353 per annum (in 2011/12 dollars).[52]

4.8.2 Differentiating retail operating costs

Perth Energy considers that the cost to serve should be determined separately for the segment of customers consuming less than 50MWh per annum (that is, the non-contestable customer segment). To this end, Perth Energy indicates that the Authority should assign a discount of 10 - 20 per cent to the $81 cost to be associated with those below 50 MWh.

PUO and Horizon Power also consider that the tariff methodology should observe the differences in customer groups when setting retail operating costs for each tariff class. The PUO suggests that to do otherwise may lead to cross-subsidisation, incorrect price signals and an adverse impact on competition for particular tariff customers.[53]

The Authority agrees with the principle that the tariff estimates should reflect the efficient costs faced by a new entrant. Indeed, in the Draft Report, the average retail operating cost of approximately $81 per customer was allocated across the tariff classes (apart from the S1 and T1 tariff classes) *in proportion to* Synergy's forecast of retail operating costs for each class. The implication of this method is that small customers using less than 50 MWh per annum will have an allowance for retail operating costs of somewhat less than $2,353 per customer, while larger customers will have a higher allowance.

For the S1 and T1 tariff classes, the higher retail operating cost of $2,353 per annum (in 2011/12 dollars) was adopted, differentiating costs for this class of tariffs.[54]

In summary, the cost reflective tariffs set out in the Draft Report do account for differences in retail operating costs for the various tariff classes. The Authority is satisfied that this

[50] Ibid.

[51] The Authority notes that the average of the three recent relevant decisions set out in the paragraph above is $75.30 (in 2011/12 dollars) – once the estimated costs for FRC are excluded. Given this, the $81 may be inferred as providing some allowance for the costs of preparing for contestability. These costs relate principally to IT expenditures, including for customer billing and metering. The Authority has taken this fact into account in its recommendation on an allowance for depreciation (see section on depreciation below).

[52] Frontier Economics 2012, *Retail Operating Costs: A Report Prepared for the Economic Regulation Authority of Western Australia*, www.erawa.com, p. 33.

[53] The PUO notes that the Authority highlights in the Draft Report that retail operating costs will vary between contestable and non-contestable customers, and the recommendation that any additional costs associated with the contestable market should be recovered through Synergy's retail margin. However, PUO indicates that the Authority also takes a conflicting view that contestable and franchise customers should carry the same retail margin.

[54] The S1 and T1 tariffs in the Draft Report were based on this allowance.

approach is consistent with the principle of differentiating tariffs according to efficient costs.

4.8.3 Customer acquisition and retention costs

A further issue relating to the overall retail operating cost allowance is the treatment of customer acquisition and retention costs (**CARC**). As noted above, these costs were not included in the 'base' retail operating cost estimate in the Draft Report.

Synergy indicates that a separate and additional CARC cost allowance should be provided for regulated contestable tariff customers, in addition to the base retail operating costs allowance.

The Authority agrees that the cost of acquiring and retaining a customer will be a cost incurred by a new entrant and as such, should be included in the determination of efficient costs. However, it can only be recovered as an annual expense, or it is capitalised and a return on it is provided.

The Authority notes that, for the S1 and T1 tariffs, a higher retail operating cost of $2,353 per annum (in 2011/12 dollars) is used as the retail operating cost allowance (see above) already incorporates costs for CARC for these tariff classes as an annual operating cost expense. On this basis, no additional allowance for CARC is recommended for these tariffs.

With regard to all other customers, the cost of acquiring and retaining a customer must be expensed or capitalised, not both. In its determination of retail margin (see Chapter 6), the Authority has capitalised the value of CARC for all customers (excluding S1 and T1). An annual return on that capitalised value therefore is included in the overall efficient tariffs through the retail margin.

4.8.4 Escalation of the retail operating cost allowance

Having determined the base retail operating cost of approximately $81 in 2012/13, an escalation rate is applied to this base operating cost to derive forecast retail operating costs for the remaining three years of the review period. To do this, the Authority considered the likely composition of the retail operating cost.

As stated in Frontier's report, a study undertaken by CRA for QCA, estimated the labour costs to account for up to 60 per cent of retail operating cost.[55] Similarly, Synergy projects labour costs will account for 40 per cent of total operating costs over the review period.[56] Accordingly, the Authority has estimated that the labour cost will constitute approximately half of the total retail operating cost. Therefore, the proportion of the labour cost should be escalated by the Labour Price Index (**LPI**) and the non-labour proportion of the costs is escalated by the consumer price index (**CPI**).

The Authority has adopted the Treasury forecasts used in the State Budget for the LPI, which are for 4.5 per cent from 2012/13.[57]: For the CPI, the Authority has adopted the Reserve Bank of Australia forecasts, as utilised for the Weighted Average Cost of Capital (see Appendix E for detail).

---

[55] CRA International, *Calculation of the Benchmarking Retail Price Index for 2007/08 and 2008/09,* draft report prepared for the QCA, 24 January 2008.

[56] Synergy data, SY_n3451924_v4_ERAInformation_Request_Spreadsheet_Incl_Efficiency_Gains2

[57] Government of Western Australia 2012, *Economic and Fiscal Outlook: Budget Paper No. 3*, p. 4

This leads to an escalator for the retail operating cost allowance of 3.75 per cent in 2012/13 and 3.5 per cent in the out years.

4.8.5 Depreciation

The Authority's recommendation on the retail operating cost does not include depreciation. Depreciation is accounted for separately in this section.

Depreciation only relates to the tangible assets of Synergy, and does not apply to the intangible asset (customer value) that was derived by using customer acquisition and retention costs (**CARC**). It is typically a relatively small component of the retail operating cost.

The Authority's calculation of the depreciation cost set out in the Draft Report was based on Synergy's tangible asset base, and using a straight line method, suggested that Synergy's depreciation cost is $14.10 per customer, on average over the four year review period.

Perth Energy notes that Synergy's depreciation cost is significantly higher than for comparable retailers. Perth Energy suggests that the Authority examine the IT system upgrade project to determine whether appropriate project management processes were followed and to ensure that unnecessary additional costs were avoided. Failing such an internal and thorough analysis of this cost to Synergy, Perth Energy indicates that the Authority should use an industry (National Electricity Market included) wide benchmark figure as an efficient depreciation cost for this purpose.

The Authority noted in the Draft Report that the significantly higher depreciation cost is due in part to Synergy's recent upgrade of its IT systems (and as discussed in the capital expenditure section above). Furthermore, IT systems have a short life over which they are depreciated, leading to a high depreciation cost. This combination of high capital expenditure and short life has resulted in a higher depreciation charge for Synergy, over the review period.

Horizon Power noted that during the Authority's 2010/11 inquiry into the funding arrangements of Horizon Power, the Authority did not allow actual capital expenditure (over and above budgeted amounts) to be included in Horizon Power's regulated capital base. [58] Horizon Power therefore considers that the same approach should be applied to Synergy's forecast capital costs.

The Authority has significant concerns in relation to the increase in the capital expenditure associated with the IT systems upgrade, and by corollary the impact this has on depreciation expenses. In this context the Authority notes that data for average per customer depreciation and amortisation expenses for energy retailers in the east involve significantly lower amounts.

More recent data on capital expenditure and customers numbers provided by Synergy, since the Draft Report was published, suggest that Synergy's average forecast depreciation expense per customer will be around $17.70 (in 2011/12 dollars). This is high compared to the recent benchmark data set out in Table 12.

[58] The Authority acknowledges that it disallowed depreciation on capital expenditure in its recommendations on Horizon Power. This was because the Authority considered that cost overruns by Horizon Power on a number of power generation projects were inefficient, compared to procurement via an independent power purchase arrangement (Economic Regulation Authority 2011, *Inquiry into the Funding Arrangements of Horizon Power: Final Report*, www.erawa.com.au, p. 87).

Table 12 AGL and Origin Energy's average depreciation per customer

Energy Retailer	Depreciation and Amortisation expense (2011/12 $m)	Depreciation and Amortisation expense (2011/12 $m)	Customer Numbers (m)	Depreciation per customer (2011/12 $ per customer)
AGL	43.8	44.5	3.2542	13.67
Origin	48.0	48.8	4.137	11.79
Average				12.70

Source: AGL and Origin 2011 annual reports

The Authority therefore has reconsidered this issue, and considers that only the budgeted IT costs of $15.5 million be allowed for the purpose of determining Synergy's depreciation (see Section 4.6). This would reduce the average depreciation per customer over the review period to $15.20 per customer (2011/12 dollars).[59]

On this basis, the Authority considers the depreciation cost for Synergy of $15.20 per customer (in 2011/12 dollars), on average, over the four year review period, to be appropriate.

4.9 Findings

1. The Authority recommends the adoption of an average retail operating cost allowance of approximately $81 per customer (in 2011/12 dollars) for the review period.

2. The Authority finds that retail operating costs should be escalated by 3.58 per cent over the review period.

3. The Authority has separately accounted for depreciation in Synergy's cost, and the Authority considers that the average annual depreciation cost of $15.20 per customer, to be appropriate. This amount excludes capital recovery for expenditure on IT in excess of budgeted amounts.

[59] The revised data from Synergy suggests that a depreciation cost – which included the actual IT expense incurred by Synergy of $48.8 million – would be $17.70 per customer on average. The final allowance is based on the budgeted IT expense of $15.5 million, and is lower than it would otherwise have been.

5 Non-Controllable Costs

There are several other types of costs that Synergy incurs in its normal course of business operations, over which it has little control. These include:

- Network charges paid to Western Power for the use of the South West Integrated Network (**SWIN**). There is little scope for Synergy to reduce these costs, which are separately determined by the Authority as part of Western Power's Access Arrangement, and recovered by Western Power from retailers and generators accessing the network.
- Costs associated with ancillary services. These are required to maintain Power System security and reliability, facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality. Synergy pays its share of the ancillary services costs, which are determined by the IMO each month.
- Market Fees that are paid to the IMO towards the costs of operating the electricity market. Again, there is little scope for Synergy to reduce these costs through its operating practices.

5.1 Draft Report

In the Draft Report, the Authority provided a number of recommendations; these were retained and are provided as final recommendations in Section 5.8 below.

5.2 Public Submissions

Synergy

Synergy noted that the IMO and System Management are undertaking significant technology upgrades to accommodate factors such as competitive balancing, and that the subsequent increase in system costs and ongoing scheduling costs will reside with System Management. It commented that this cost increase has not yet been translated into a market fee forecast.

Furthermore, Synergy discussed the potential for increases in ancillary services costs as a result of rule changes relating to the linkage of the load following service with an expansion of intermittent generation capacity. Consequently, Synergy has proposed that the allowances for the recovery of network charges, market fees and ancillary services costs be reset on an annual basis.

Finally, Synergy noted that no allowance has been made within the tariff cost stacks, nor in the retail margin, for costs related to balancing.

Public Utilities Office (Department of Finance)

The PUO indicated that the Authority had not considered all potential non-controllable costs, including balancing costs, and suggested that an appropriate methodology would address the manner in which tariffs reflect changes in non-controllable costs.

5.3 Network Charges

5.3.1 Background

Network charges paid by Synergy to Western Power are a major component of Synergy's costs, representing around 33 per cent of Synergy's cost of sales. Synergy's network charges are budgeted at $811 million in 2011/12.[60]

A component of Synergy's network charge payment to Western Power is its contribution to the Tariff Equalisation Fund, which was established to support the uniform tariff policy, so that small use electricity customers in regional areas of Western Australia, serviced by Horizon Power, pay the same electricity tariffs as small use customers in the SWIS. Synergy pays its Tariff Equalisation Contribution (**TEC**) to Western Power as part of distribution network charges, and Western Power passes the TEC on to Horizon Power. The amount of the TEC is determined by the government and published annually in the Government Gazette. The TEC was set at $175.7 million for 2010/11 and $181.2 million for 2011/12.[61]

The Authority regulates electricity network charges as part of Western Power's Access Arrangements. The Authority released its draft decision on Western Power's third Access Arrangement on 29 March 2012. The Authority's final determination on Western Power's third Access Arrangement is due to be delivered in mid-2012. For the purpose of this report, the Authority's draft determination on Western Power's third Access Arrangement has been used.[62] Tariffs will have to be updated to reflect the final outcome of the Access Arrangement. This will also impact the amount of the TEC allocated to each tariff.

5.3.2 Authority's Assessment

The network costs incurred by Synergy for use of the network are outside the control of Synergy. The Authority will therefore treat these charges as costs that should be passed through to Synergy's customers.

The Authority notes that Western Power's network charges currently include payments collected by Western Power under the TEC to facilitate the State Government's uniform electricity tariff policy so that customers in regional Western Australia pay the same prices for electricity as SWIS customers. The Authority considers that the TEC should be funded by a CSO payment to make this cost more transparent and to ensure that it is shared by all taxpayers in Western Australia. In calculating the efficient cost reflective level of tariffs, the Authority has assumed that this subsidy to Horizon Power is no longer met by electricity consumers in the South West. This subsidy is not a cost that is associated with generating, distributing or retailing electricity in the South West. It is a tax that is arbitrarily imposed on a narrow base of electricity customers in the South West, on the basis of a government policy decision. Just as the subsidy for Water Corporation's regional customers is not paid for by Perth customers, neither should the subsidy for regional consumers of electricity be paid for by Synergy's customers. The subsidy should come out of general taxation revenue. This arrangement will also have the benefit of removing the cross-subsidisation of regional Western Australian customers by customers in the SWIS. Furthermore, the need to include TEC as a component of network costs adds further complexity to the process of setting electricity tariffs.

---

[60] Data provided by Synergy to ERA on 6 March 2012.

[61] *Government Gazette* (November 2009), no. 208, p4639.

[62] Available on the Authority's website.

The Authority has observed significant increases in the TEC since the disaggregation of the old Western Power Corporation in 2006. The gazetted TEC amount for 2011/12 of $181.2 million is more than double the amount set for 2006/07 of $69.7 million. The Authority estimates the impact of the TEC on a typical household's annual electricity bill has increased from $35 in 2006/07 to $83 in 2011/12.

The Authority notes that Western Power's proposed third Access Arrangement has included a total TEC amount with a present value approaching $0.7 billion dollars, or around $180 million per annum over the five year period from 2012/13 to 2016/17 in nominal dollars. Only a proportion of the TEC is charged to Synergy's tariff customers, with the remainder charged to Synergy's non-tariff customers and other Western Power SWIS network users. The Authority's estimate of the TEC attributable to Synergy's tariff customers is shown in Table 13 below.

Table 13 TEC Attributable to Synergy's Tariff Customers and Total TEC ($m, nominal) 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Synergy Tariff TEC	-125.45	-127.05	-129.65	-133.14
Total TEC	-186.60	-190.80	-195.70	-201.50

Source: ERA Analysis

The Authority completed an inquiry into the funding arrangement for Horizon Power in 2011 and recommended reductions to Horizon Power's operating costs and capital expenditure, based on the efficient cost of service, and hence reduced TEC requirements. The Authority has not seen these recommended cost reductions being built into the TEC forecast in Western Power's proposed third Access Arrangement.

The network cost forecasts for Synergy to 2015/16 are calculated by multiplying Synergy's volume forecasts by the regulated network charges over that period.

Based on the Authority's draft decision on Western Power's third Access Arrangement, the Authority's estimates of Synergy's total network costs over the period to 2015/16 are set out in Table 14.

Table 14 Synergy's Tariff Volume, Network Charges and Costs 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Volume (GWh)	7,938	7,860	7,820	7,802
Network Charges (c/kWh)				
- TEC exclusive	8.96	9.14	9.37	9.67
- TEC inclusive	10.54	10.76	11.03	11.37
Network Costs ($m)				
- TEC exclusive	711.4	718.6	733.0	754.2
- TEC inclusive	836.9	845.7	862.7	887.3

Source: ERA Analysis

5.4 Ancillary Services Costs

5.4.1 Background

Ancillary services are necessary to maintain the balance between supply and demand, system security, and system frequency. As a registered market customer in the WEM, Synergy is allocated a share of the ancillary services costs, mainly relating to load following, system restart, load rejection reserve and dispatch support ancillary services.

Synergy has provided information on its actual and forecast ancillary services costs. In regard to the ancillary services costs, Synergy has advised that it does not forecast these costs at a detailed level, due to the high degree of complexity and relatively small amounts involved (typically the costs make up less than 0.5 per cent of Synergy's total costs of goods sold). Instead, forecasts are set based on a similar approach applied by Frontier Economics in the 2009 Electricity Retail Market Review (**ERMR**).

Table 15 below provides information on Synergy's actual ancillary services costs for the 2009/10 and 2010/11 financial years, and forecasts for the following five financial years.

Table 15 Actual and Forecast Ancillary Services Costs Paid by Synergy ($m) 2009/10 to 2015/16

Actual		Forecasts				
2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
9.4	14.1	15.70	16.26	16.88	17.49	18.18

Source: Synergy

Note: The ancillary services costs are currently spread across all sales at average levels by Synergy, which are then allocated to customer groups and tariff classes on the basis of annual forecast sales.

5.4.2 Authority Assessment

The Authority has reviewed the information provided by Synergy.

Firstly, the Authority is aware of the increases in the cost associated with Load Following Ancillary Service (**LFAS**) in the market over recent years. For instance, the cost of LFAS has increased from $7.6 million for the period from 1 April 2009 to 31 March 2010, to $11.4 million for the period from 1 April 2010 to 31 March 2011.63 The cost of LFAS is dependent on the generation capacity required for providing the service and the real time balancing price during the trading intervals.

The Authority recognises that a further cost increase is likely in 2011/12 due to the commissioning of the Collgar wind farm (206 MW) in October 2011, and in order to meet the SWIS Operating Standards, as defined in the Market Rules. The load following capacity requirement for 2011/12, as determined by System Management, has shown an increase in the required load following capacity from +/-60MW in July 2011 to +/-90MW for November 2011 and onwards.

[63] System Management Ancillary Service Report 2011.

Secondly, the cost associated with Spinning Reserve Service has also increased over recent years, as a result of the revised margin value parameters determined by the Authority. With the introduction of the carbon pricing regime from 1 July 2012, the Authority considers that there will be further cost increases. System restart cost has almost doubled in 2011/12, as the service arrangement assigned to Verve Energy prior to the market commencement expired in June 2011.

Thirdly, the Authority expects that costs associated with dispatch support will also increase from 1 July 2012, with the introduction of the carbon pricing regime.

Overall, the Authority considers that Synergy's forecast ancillary service costs are reasonable based on the provided information.

5.5 Market Fees

5.5.1 Background

As a participant in the wholesale energy market, Synergy is required to pay market fees to the IMO to cover the costs of functions performed by the IMO, System Management and the Authority.

The market fees apply to all energy traded on the market, including energy bought or sold through bilateral contracts. The fees are calculated on the basis of the estimated total revenue requirement for each year (derived from the budget estimates of the IMO, System Management and the Authority's market-related functions), divided by the projected total MWh of energy supply and consumption in the WEM for the year.

The total market fee is set per MWh of energy traded, and is set at $0.556 per MWh for 2011/12, based on an estimated 38,370 GWh of trading volume.[64] The total fee comprises:

- IMO Market Fee $0.327 per MWh;
- System Management Fee $0.195 per MWh; and
- Economic Regulation Authority Fee $0.034 per MWh.

The Authority notes that the market fee rate published by the IMO for the 2011/12 financial year ($0.327 per MWh) includes the impact of the Market Evolution Program fee rate of $0.033/MWh.

5.5.2 Authority's Assessment

Synergy's approach to forecasting its market fees, which is not very detailed, is based on the assumptions in the 2009 ERMR report by Frontier.[65] In this report, Frontier noted that it is difficult to predict how market fees might vary in future years, due to the absence of information on forecast fee rates from the IMO, as well as information on forecast revenue requirements. As a result, Frontier based its market fees calculation on the market fee rate of $0.468/MWh for 2007/08, as published by the IMO, and assumed the market fee rate to remain constant in real terms over the period to 2011/12.

[64] IMO website.

[65] Frontier Economics Pty Ltd., Melbourne, January 2009, *Electricity Retail Market Review – Electricity Tariffs*, pp49-50.

Synergy has adopted Frontier's view that revenue requirements, and therefore market fees, will be relatively stable over time. For this reason, and in the absence of better information, Synergy also adopted Frontier's assumption that fee rates will remain relatively constant in real terms over the inquiry period to 2015/16.

Table 16 shows the actual market fees paid by Synergy in 2009/10 and 2010/11, and Synergy's forecast market fees for the next five years.

Table 16 Synergy's Actual and Forecast Market Fees ($m) 2009/10 to 2015/16

Actual		Forecasts				
2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
5.6	7.0	6.39	6.62	6.87	7.10	7.37

Source: Synergy

The total revenue requirement to be recovered through market fees is spread across both energy supply and energy consumption volumes as measured in MWhs. As a market customer, Synergy pays its share of the market fees based on its transactions in the WEM, including the bilateral market, STEM and balancing market. Synergy's transaction volume in the WEM reflects the sales volume to its customers.

The Authority has noted the large increase in Synergy's reported market fees payment in 2010/11, which are 25 per cent higher than the reported market fees for 2009/10. However, Synergy's forecast market fees payment for 2011/12 is 11 per cent lower than the actual payment in 2010/11, whilst the market fee rate has increased from $0.551/MWh in 2010/11 to $0.556/MWh in 2011/12.

The Authority has examined some relevant information provided by Synergy and noted that Synergy expected a reduction of 3.3 per cent in its sales volume in 2011/12, compared to the 2010/11 level. Based on Synergy's sales volume projection for 2011/12 and the published market fee rate, the Authority's calculation indicates that Synergy's market fees payment in 2011/12 is likely to be close to $7 million, i.e. at a similar level as the 2010/11 actual payment. The Authority is aware of the cost pressure associated with the implementation of the new competitive balancing and LFAS market and considers that Synergy's forecast for the period from 2012/13 to 2015/16 is likely to be at the lower end.

5.6 Balancing Costs

Both Synergy and the PUO have commented in their submissions to the Authority's Draft Report that the Authority has not included balancing costs in its calculation of the tariffs. Synergy's participation in the market involves transactions with the IMO to settle variations from its nominations to the market, based on its day-ahead forecasts. The net outcome of these balancing transactions can be either positive (as an income to Synergy) or negative (as a cost to Synergy). Synergy's has estimated that the net outcomes of its balancing transactions with the market, for the period from 2012/13 to 2015/16, will be a cost of approximately $22 to $23 million per year, as shown in Table 17 below.

Table 17 Synergy's Net Forecast Balancing Costs ($m) 2012/13 to 2015/16

Forecast Balancing Costs			
2012/13	2013/14	2014/15	2015/16
22.5	22.6	22.9	23.1

Source: Synergy

The Authority considers that forecast uncertainty is a risk faced by retailers as part of their normal business operations. This risk has been taken into account in the rate of return for retailers. Synergy's estimates of a net balancing cost for each of the four years from 2012/13 to 2015/16 indicate that there will be systematic under-forecasts in its day-ahead nominations to the market, which is not a justified position. It is the Authority's view that it is not appropriate to accept these cost estimates as part of an efficient cost stack for Synergy, as it will not provide any incentive for Synergy to improve its forecasting process and systems.

5.7 Adjustment mechanism for non-controllable costs

5.7.1 Background

In the Draft Report, the Authority considered that forecasts of non-controllable costs provided a reasonable means on which to base estimates of efficient prices for regulated electricity tariffs.

The PUO and Synergy suggested that the Authority should propose a methodology of how tariffs would appropriately reflect changes in non-controllable costs. Synergy proposed an annual adjustment mechanism, noting:[66]

> The level of these costs have the ability to vary significantly from the current forecasts. In particular, the IMO and System Management are undertaking significant technology upgrades to accommodate such factors as competitive balancing, the gas bulletin board and gas statement of opportunity.
>
> Whilst the IMO has indicated its portion of the market fees resulting from system improvements will only modestly increase in real terms, Synergy understands that the bulk of the system costs and ongoing scheduling costs will reside with System Management. This cost increase has not yet been translated into a market fee forecast.
>
> Ancillary Services costs could also vary because of rule changes related to making the load following service linked with an expansion of intermittent generation capacity.

5.7.2 Authority Assessment

The Authority recognises that actual outcomes for Synergy's non-controllable cost components will differ from those that are forecast. The Authority considers that some mechanism to allow a 'true up' between forecast and actual outcomes is warranted.

[66] Synergy 2012, *Submission regarding the ERA's Draft Report: Inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs*, www.erawa.com.au, p. 9.

Two broad approaches are possible. The first could involve an annual adjustment (as suggested by Synergy). The second approach could space adjustments further apart, such as at each major review of efficient tariffs, and take account of discount rates to ensure that tariff revenues are adjusted in real terms.

Arguments for an annual variation include:

- network charges are around 33 per cent of the total cost of regulated tariffs, and will change depending on the difference between forecast and actual inflation outcomes;
- market fees may change significantly, as noted by Synergy.

Arguments for a 'true up' at the next tariff reset include:

- the forecast error amounts involved are expected to be relatively small, with likely changes in tariffs around plus or minus 1 per cent over a four year period;[67] and
- a single true-up is likely to be less resource intensive, and create greater certainty for customers with regard to tariff paths over the immediate future.

On balance, the Authority is of the view that a 'true up' at each tariff review is preferable. This accounts for the relatively small amounts involved, and the resource costs involved with resetting tariffs every year.

The formula for the reset is as follows:

$$C_{R\,N-C} = \sum_{t=1}^{n}(N_F^t - N_A^t) + \sum_{t=1}^{n}(A_F^t - A_A^t) + \sum_{t=1}^{n}(M_F^t - M_A^t)$$

where:

- $C_{R\,N\text{-}C}$ are the real non-controllable costs carried forward to the first year of the next review period;
- N_F are the forecasts of network costs in real dollars;
- N_A are the actual network costs in real dollars;
- A_F are the forecasts of ancillary services costs in real dollars;
- A_A are the actual ancillary services costs in real dollars;
- M_F are the forecasts of market fee costs in real dollars;
- M_A are the actual market fee costs in real dollars.

[67] For example, a 1 per cent forecast error in inflation annually would lead to a tariff cost differential of 0.33 per cent annually due to the implied changes in network charges. Over four years this could lead to a cumulative forecast error of 1.3 per cent. However, it is more likely that there would be some balancing of 'unders' by 'overs', such that the actual amount was less than this.

5.8 Findings

1. Synergy has little control over its ancillary services costs. The Authority therefore recommends that forecast costs for ancillary services be included in the costs to be recovered from Synergy's customers.

2. As a participant in the WEM, Synergy cannot avoid market fees and has little influence on the expenditures incurred by the IMO and System Management. The Authority therefore considers that it is appropriate for Synergy to recover the payment in full from its customers.

3. The Authority considers Synergy's forecasting uncertainty risk is appropriately taken into account in its rate of return, and that it is therefore inappropriate to include balancing costs in Synergy's efficient cost stack.

4. Any differences between forecast and actual non-controllable costs should be adjusted for in real terms at the next major review.

6 Retail Margin

6.1 Background

The retail margin represents the risk-adjusted return a retailer operating in a competitive market can earn on the investment it has made in order to provide retail services. Without a retail margin the retailer would not have an incentive to provide retail services and there would be no incentive for other retailers to enter the market.

The retail margin is expressed as a per cent that is applied to total input costs. Currently Synergy applies a retail margin of 3.4 per cent to their non-contestable business and 5 per cent to their contestable business. These margins are applied to their costs, which include their own cost to serve as well as the costs of energy, capacity, networks, RECs, market fees, ancillary costs and balancing.

The equivalent to a retail margin (expressed as a percentage) in the case of an electricity network is the risk adjusted regulatory rate of return. A rate of return is determined as the product between the rate of return and the regulatory asset base. However, such an approach cannot be as readily applied to an electricity retail business such as Synergy because the value of its asset base is dependent on the intangible value of its customer base, rather than the value of is physical assets.

In this chapter, in determining an appropriate retail margin for Synergy, the Authority has considered a number of possible approaches, including a benchmarking approach (examining the reported margins of comparable companies) and a bottom-up approach (determining the risk-adjusted return on investment). These approaches are discussed below, after the discussion on public submissions.

6.2 Draft Report

The Authority recommended in the Draft Report that an appropriate retail margin for Synergy for the next four years would be 3.5 per cent of its total cost.

6.3 Public Submissions

Synergy

Synergy indicated that the risks associated with contestable tariff customers are greater than for non-contestable customers, and therefore a separate and higher retail margin should be assigned to contestable tariff customers.

Synergy also expressed concern with the methodology adopted by the Authority for the calculation of retail margins, noting that while it may be theoretically sound to consider the cost of acquiring and retaining customers as an approach for calculating an intangible asset value, it also poses issues of verification and calculation.

Public Utilities Office (Department of Finance)

The PUO reiterated the concerns provided by Synergy and Horizon Power, supporting the adoption of separate retail margins for contestable and non-contestable customers.

Western Australian Council of Social Service Inc. (WACOSS)

WACOSS queried the methodology used to determine the cost of customer acquisition and retention, noting that a benchmarking against Eastern States utility regulators may be inappropriate given the SWIS is structured in a manner that is not comparable with the NEM.

WACOSS further submitted that any costs incurred by Synergy in relation to CARC will be significantly lower than those incurred by retailers in the National Electricity Market. WACOSS supported this point with the reasoning that the requirement in the Authority's terms of reference to 'consider and develop findings on the efficiency of Synergy's operating and capital expenditure' can only be fulfilled by analysing Synergy's current and expected expenditure independently of considering the costs as they would relate to a theoretical new entrant to the market. WACOSS considered that there is no justification for including the full estimated costs of the retail margin until full retail contestability is introduced.

Horizon Power

Horizon Power did not support the Authority's adoption of a single retail margin, and comments that the risk of retailing to different customer classes should be recognised through the adoption of varying retail margins depending on the risk associated with different customer classes.

6.4 Benchmarking Approach

The benchmarking approach examines the reported margins of comparable electricity retailers interstate and some international benchmarks, to establish a range for the retail margin. For reasons of commercial confidentiality, retail margins applied in market contracts are not transparent. However, for most of these markets, regulated tariffs continue to apply, and these margins are transparently reported. Benchmarking in this environment means that reference is made to regulators' retail margin estimations.

Although care is taken in selecting the relevant businesses with which to compare the margins, it is inevitable that international benchmarking results are less relevant given the differences between jurisdictions in operating environments, associated risks and regulatory and governance frameworks. Many retailers incorporate other operations into their business, such as food retail or power generation, while others specialise in green energy. Furthermore, the results show considerable dispersion.

The Authority has considered the retail margins adopted by other Australian regulators. The retail margins, expressed as the earnings before interest, taxation, depreciation and amortisation (EBITDA) as a percent of total costs, adopted by other Australian regulators in recent years are presented in Table 18 below.

Table 18 Retail Margin Expressed as EBITDA per cent of Total Costs Adopted by Australian Regulators in the National Electricity Market

IPART 2010/11	QCA 2010/11	ICRC 2010/11	ESCOSA 2009/10	Tasmanian Economic Regulator 2010/11
5.4%	5.0%	5.4%	5.0%	3.7%

Source: Compiled by the ERA from other Australian regulatory decisions

Table 18 indicates that the range of the EBITDA retail margin, expressed as a percentage margin on total costs, adopted by other Australian regulators recently has been between 3.7 per cent (Tasmania) and 5.4 per cent (New South Wales). Most regulators have provided a retail margin of 5.0 per cent or more.

The shortcoming of this approach lies in the fact that most of these regulatory decisions are based on benchmarking other regulatory decisions. Although this leads to consistency in regulatory decisions, it does not, in itself, imply a robust and accurate calculation. As such, the Authority has undertaken a bottom-up analysis to overcome problems associated with the benchmarking approach.

6.5 Bottom-Up Approach

Like all similar businesses in Western Australia, Synergy faces risks in supplying electricity to customers. Some of the risks involved are systematic risk (which cannot be diversified or eliminated) and some of the risks involved are non-systematic in nature, which could be diversified. For example, due to economic conditions, electricity demand by all customers may decrease. This is a systematic risk faced by all industry participants, and in Synergy's case will be compensated via the retail margin – because the risk arises from the exposure to the overall economic conditions. In contrast, non-systematic risks relate to individual firms' risks, such as those associated with their particular mix of contracts or customers. These are not compensated for by the retail margin, but rather will be reflected in the profit outcomes of individual businesses – which may be higher or lower, depending on actual performance.

The central premise in the bottom-up analysis is that the profit margin is a proxy for the risk-adjusted return on the investment made by the investors in a retail business. The bottom-up analysis, therefore, estimates the risk-adjusted return that an electricity retailer should earn to compensate the business for bearing the risk, and applies this return to the estimated value of the investment made in the business. This arrives at a dollar value return to the investor which can be expressed in percentage terms by calculating the value as a proportion of total costs. This percentage is averaged out over the review period to arrive at a figure like those presented in Table 18.

A bottom-up approach relies upon an assumed asset base and demand forecasts, to ensure that the retailer is only allowed to earn an expected return equal to its estimated cost of capital to compensate for the level of systematic risk the business faces. Retail businesses such as Synergy have relatively small tangible asset bases, compared to network service providers such as Western Power. Synergy's tangible assets consist mainly of IT and communications infrastructure. However, much of the value of a retail business lies in its intangible assets, which is predominantly the value of its customer base.

With regard to the Authority's bottom-up approach, the assumed asset base for a retail business is estimated. The retail margin is then derived by applying a cost of capital (which proxies the rate of return) on a derived asset base.

The derivation of the appropriate rate of return and a discussion on the valuation of deemed investment in the retail business is set out in the following sections.

6.5.1 Rate of return

The rate of return that any business should earn relates to the riskiness of the business. To capture this relationship, the Capital Asset Pricing Model (**CAPM**) has been utilised by Australian Regulators.[68] This finance model is applied for the purpose of deriving the risk-adjusted return for an efficient electricity retailer.

The WACC previously utilised for the Draft Report was based on the assumption, among others, that an electricity retailer such as Synergy would have zero debt in its financing. The resulting nominal pre-tax rate of return was calculated, using the Authority's WACC method, to be 7.52 per cent as at 29 February 2012. This return of 7.52 per cent was applied to the estimates of the asset value for Synergy to reflect the dollar value of the retail margin.

The Authority has reconsidered its position on the appropriate WACC to apply for this report. The Authority notes that the WACC is used to determine the return on capital for generators as part of the LRMC calculation. The WACC is also used to derive the returns on the efficient retailer's asset base for the purposes of calculating the retail margin. For this Final Report, the Authority considers that a WACC that reflects the parameters of a generator in the Western Australian market is most appropriate, including a gearing level of 40 per cent. This is the correct WACC to use for the LRMC calculations. It is also a reasonable WACC to adopt for the retail business, as the levels of risk faced by retailers and generators tend to be similar. Both types of business are susceptible to the same unexpected fluctuations in demand, and it is likely that an efficient new entrant to the retail market in Western Australia would be a 'gentailer'. To this end, the Authority has updated the WACC utilised by the IMO for the purposes of calculating the Maximum Capacity Reserve Price.[69] The Authority has also incorporated its bond yield approach.

The resulting real pre-tax WACC estimate is 6.66 per cent (this corresponds to a 9.17 per cent nominal pre-tax WACC – see Appendix E for the detail of these calculations). This revised real pre-tax WACC of 6.66 per cent is taken as a point of reference in what follows.

Synergy submits that the WACC determined by the Authority in the Draft Report was inappropriate. Synergy noted that the Authority's real pre-tax WACC of 4.9 per cent is below the lower boundary of the WACC range proposed by Frontier Economics and IPART, and that an appropriate real pre-tax WACC should be close to IPART's 2011 mid-point real pre-tax estimate for electricity retail business of 8.9 per cent.

Key estimates driving the difference between the Authority's recommendation and IPART's recent draft decision mid-point estimate include:

[68] For a detailed discussion on the CAPM and its application on the determination of regulatory rate of return, see the Authority's discussion on Western Power's Access Arrangement 3, available on the ERA website.

[69] The IMO's WACC is based on work undertaken by the Allen Consulting Group (see Allen Consulting Group 2009, *WACC Parameters Update*, www.imowa.com).

- the forecast inflation rate of 3.0 per cent for 2012/13 and 2.5 per cent for the remaining three years (compared to IPART's 3.0 per cent for a single year);
- the equity proportion of 60 per cent (compared to IPART's 70 per cent);
- the equity beta of 0.83 (compared to IPART's 0.9 to 1.1); and
- the franking credit gamma of 0.25 (compared to IPART's 0.4).

Each of these differences is discussed in what follows.

First, the Authority's forecast of inflation relates to average expected inflation over the review period. IPART's higher estimate on the other hand is for the single year 2012/13.

Second, as noted above, the equity proportion of 60 per cent and equity beta of 0.83 – adopted for this final report – are based on the IMO's WACC parameters for a generator in the Wholesale Electricity Market. In addition, the IMO's WACC parameter for the debt margin has been updated for the Authority's latest estimates using the bond yield method. The Authority considers that these figures reflect the best available evidence for the WACC parameters for generation and retail businesses operating in the WEM.

Third, the franking credit gamma value of 0.25 adopted by the Authority is consistent with the Australian Competition Tribunal's recent decision on gamma.

For these reasons, the Authority considers that its estimate adopted for the WACC, of 6.66 per cent (real, pre-tax), is reasonable.

6.5.2 Asset Valuation

The customer base of an electricity retailer has a value – it is an asset that generates revenues for the business. As such, the customer base is considered an intangible asset of the retail business which can be incorporated into the value of the total assets, or the asset base, when there is a merger or acquisition of the business. There is no general agreement on the approach by which the value of intangible assets such as a customer base should be valued.

The Authority considered two possible approaches in estimating an appropriate regulatory asset base for a retail business:

- the cost of acquiring a comparable business, and
- the cost of building up a customer base through customer acquisition and retention.

These two methods are considered and compared below.

6.5.2.1 Cost of Acquiring a Business

The Authority obtained a list of ten transactions of Australian electricity and gas retailers used by SFG in 2010 to provide its advice to IPART. The amount paid to acquire a 100 per cent interest in the business was estimated and then adjusted for inflation as at 31 December 2011. This was then converted to a dollar value per customer. For the entire sample of ten transactions of Australian electricity and gas retailers, the median value was approximately $1,000 per customer and $70 per MWh.

Table 19 below adopts a total asset base approach, based on the cost of acquiring a comparable business.

Table 19 Cost of Acquiring a Business, Total Asset Base ($ million) 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Customer Based Method	1,177.4	1,193.0	1,211.6	1,232.4
MWh Based Method	628.0	615.4	604.9	599.2
Average of Two Methods	902.7	904.2	908.2	915.8

Source: ERA Analysis, based on Synergy's balance sheets and profit and loss statements

Using the average of the asset bases above from the cost of acquiring a business method and WACC estimates of 6.66 per cent, the results shown in Table 20 were attained:

Table 20 Estimated Regulatory Asset Base and Associated Retail Margin ($ million) 2011/12 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Total Asset Value	902.7	904.2	908.2	915.8
Retail Margin	60.1	60.2	60.5	61.0

Source: ERA Analysis

The dollar value of the retail margin for Synergy is around $55 million per year when the cost of acquiring the business is considered. This equates to approximately 2.9 per cent to 3.4 per cent when the retail margin is expressed as a percentage of the total cost for Synergy for the next five years.

Although useful for cross checking purposes, the problem with this approach is that the calculations of the asset base by those conducting the transactions are based on the expectations of the retail margins as set by economic regulators. This creates circularity, where the value of the business is dependent on the regulatory margins, and regulators are using that value to determine an appropriate margin.

To overcome this circularity problem, the Authority considered another approach to determine the value of investment, as described below.

6.5.2.2 Cost of Acquiring and Retaining Customers (CARC)

The central premise in this methodology is that, similar to the replacement cost valuation methodology in the network business, the value of a customer base for electricity retailers can be derived by capitalising the cost of acquiring and retaining a customer (**CARC**). This valuation methodology is also consistent with the underlying principle of emulating the outcome of a competitive market.

To derive the CARC value for Synergy, the Authority considered the average CARC values in competitive markets in other Australian States.

The approach spreads the total costs of customer acquisition over an appropriate period, with this being the period a customer might on average be expected to remain with the retailer, based on analysed rates of churn. The retention costs are rarely determined separately from the acquisition costs, as they are relatively small and are difficult to identify, given that many acquisition activities also impact customer retention. Using this approach, an annual CARC value per customer is derived, which is then multiplied by the number of customers in the regulated market, to determine the value of the regulatory asset base.

A number of jurisdictions with relatively competitive retail electricity markets were considered to determine a reasonable range for Synergy's annual customer acquisition and retention costs. These are summarised in Table 21 below.

Table 21 Regulatory Customer Acquisition and Retention Cost Estimates

Queensland[(a)]	New South Wales[(b)]	South Australia[(c)]	Victoria[(d)]
$40.52	$28 - $45	$41.90	$49.00

Source: Analysis from various Australian jurisdictions [70]

Given these findings, it appears that a reasonable annual average CARC for an efficient retailer in Western Australia, based on competitive retail markets elsewhere in Australia, would fall within the range of $30 to $50 per customer per year.[71]

The Authority has given consideration to defining a reasonable estimate of the CARC from the above range of $30 to $50 per customer per year that would best meet the objectives of the inquiry. However, while the Authority recognises that it would be unreasonable to adopt either of the extremes of this range, the Authority is of the view that there is no apparent rigorous method for determining precisely which point estimate of a CARC reflects a reasonable view for Synergy. Furthermore, with the exception of the $28 and $49 per customer per year extremes, the CARC estimates are narrowly clustered around $40 per customer. The Authority thus considers a CARC of $40 (in 2011/12 dollars) to be a reasonable value for the purposes of valuing intangible assets in Synergy's regulated asset base.

The net present value of the intangible asset reflecting Synergy's customer base is estimated through the following steps:

- the annual intangible asset real value is determined by multiplying Synergy's various tariff customer numbers in each year (excluding S1 and T1 customers) by the real value of the CARC;
- this value is divided by the WACC of 6.66 per cent (real, pre-tax) – giving the real net present value of Synergy's customer asset base to perpetuity;

---

[70] Queensland Competition Authority (2011), *Final Decision – Benchmark Retail Cost Index for Electricity, 2011-12.*

IPART (2009), *Final Determination – Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013*

LECG Consultants (2010), *Report to the Essential Services Commission of South Australia*

CRA International (2007), *Impact of Prices and Profit Margins on Energy Retail Competition in Victoria,* a report prepared for the Australian Energy Market Commission

[71] The average CARC is for all customers. It is recognised that there will be differences in CARC depending on their energy consumption.

- a value to perpetuity is considered appropriate as the majority of Synergy's customers are non-contestable customers, and Synergy is expected to retain a significant proportion of its contestable customers;
- furthermore, Synergy's forecast operating costs are related to its current customer base, implying that to the extent that there was a net loss of contestable customers by Synergy through future churn, then Synergy's operating costs would fall in proportion to that loss – such that the calculated retail margin would remain virtually unchanged (apart from a minor impact of the small proportion of fixed costs);
- the real value of the customer base to perpetuity is taken as the intangible asset.

The final step in this valuation methodology is to add the tangible asset values, including an estimate for the working capital required to operate the regulated part of Synergy, to the value of the customer base.

The need for a return on working capital is dependent on the assumptions made with regard to the timing of the cash flows. For the purposes of this inquiry, the Authority is of the view that working capital should be included in the estimates of the regulatory asset base for electricity retailers because it is expected that there is a significant mismatch between the day the company pays for its account payables (for electricity generators) and receives from its account receivables (from customers), and this mismatch has not been compensated for in the financial modelling assumptions.

Based on information provided by Synergy, the estimated regulatory asset base using the cost of acquiring and retaining customers is presented in Table 22 below.

Table 22 Estimated Value of Synergy's Regulated Asset Base (Tangible Asset Values in $m 2011/12 dollars) 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Fixed Investment	30.2	22.5	12.7	5.8
Working Capital	227.3	228.8	241.5	241.5
CARC[72]	614.5	643.0	674.0	704.3
Total	**872.0**	**894.3**	**928.2**	**951.7**

Source: ERA Analysis based on Synergy Balance Sheet and Profit and Loss Statements

The final step is to multiply the estimated asset base by the nominal pre-tax WACC, to give a value for retail margin. The resulting dollar value of the retail margin for Synergy is in the range of $60 million to $70 million per year when CARC methodology for valuing the intangible asset is considered (Table 23). This equates to approximately 2.8 per cent to 3.1 per cent when the retail margin is expressed as a percentage of the total cost for Synergy for the next five years.

[72] A cost of acquiring and retaining customers (CARC) is calculated from the CARC per customer, which is $40, and a forecasted numbers of total customers from Synergy over the next 5 years.

Table 23 Estimated Regulatory Asset Base and Associated Retail Margin ($m 2011/12 dollars) 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Total Asset Value	872.0	894.3	928.2	951.7
Retail Margin	$59.8	$62.9	$66.9	$70.3

Source: ERA Analysis

Synergy indicates that the benchmark CARC range from other jurisdictions set out in Table 21 – of between $28 and $49 per customer per annum – is too broad to provide a reasonable cost estimate for the purpose at hand. Synergy's preference is for the adoption of a methodology based on the cost of acquiring a comparable business.

However, as noted, the Authority considers that these estimates are reasonably clustered and that as a result the range provides the best means for valuing customer intangible assets. The Authority also notes that in coming to its recommendation, it took account of all the available information – including Synergy's proposal, benchmarks and the data from both the bottom up methods.

6.6 Authority's Assessment

The Authority notes there is no single technique that can accurately determine Synergy's retail margin. All techniques either suffer from circularity problems, or rely on an imprecise range to estimate the retail margin. However, (except for the benchmarking approach, which suffers the most from the circularity problem) all other approaches considered by the Authority indicate a range of 2.8 per cent to 3.4 per cent.

On this basis, in recommending a point estimate for the retail margin, the Authority considered the range of outcomes, including the weighted average derived from Synergy's proposal, to form the view set out in the Draft Report that a retail margin of 3.5 per cent best reflects the efficient point estimate of Synergy's retail margin.

The view was based on the following considerations:

- the benchmarking approach is a circular approach as regulators tend to base their decisions on the retail margin on previous decisions of other regulators, who are likely to have, in turn, used a benchmarking approach. This approach results in a very wide range, from 3.7 per cent to 5.4 per cent;
- a bottom-up analysis using the cost of acquiring a business method presents that a retail margin falls within the range of 2.9 per cent and 3.4 per cent. This method is somewhat imprecise since the financial valuation of business depends on the expected profit margin;
- a bottom-up analysis using the cost of acquiring and retaining customers based on a CARC of $40 returns a range from 2.8 per cent to 3.1 per cent; and
- the weighted average retail margin, based on Synergy's proposal of 3.4 per cent for non-contestable customers and 5 per cent for contestable customers returns a value of 3.6 per cent.

Synergy, Horizon Power and the PUO submitted that separate retail margins should be used for contestable and non-contestable customers. PUO indicated that to do otherwise may lead to cross-subsidisation between customer groups and impair competition in the contestable segments of the market.

The Authority does not consider that the retail margin should be differentiated for contestable and non-contestable customers. The retail margin should reflect the systematic risks of the industry as a whole, not the non-systematic risks associated with the mix of customers retained by a particular business. The principle applied when setting regulated tariffs is to achieve the same outcome as would apply if markets were fully competitive. The Authority would not expect the retail margin to rise if the industry moved to FRC. For this reason, the tariffs for both Synergy's contestable and non-contestable customers should reflect the levels of risk which would apply in a competitive market setting. Further, the practice of adopting multiple retail margins would be largely inconsistent with regulatory decisions in other jurisdictions.

However, the Authority notes that the benchmark range for CARC was utilised to derive the intangible asset value of the customer base – as an input to determining the retail margin. The Authority considers that this retail margin should be consistent with that derived from the efficient operation of a typical business in the electricity retailing sector. To apply any other retail margin would not be efficient, and would breach principles of competitive neutrality.

In conclusion, the Authority remains of the view that a single retail margin of 3.5 per cent best reflects the efficient point estimate of Synergy's retail margin.

6.7 Findings

1. The Authority has found that an appropriate retail margin for Synergy for the next four years is 3.5 per cent of its total cost.

7 Electricity Tariffs

7.1 Background

In line with the Terms of Reference for this inquiry, the Authority is required to determine the efficient cost reflective level for each regulated tariff. As noted in Section 1.2, moving towards cost reflective tariffs is necessary to the development of a competitive electricity retail market in Western Australia, and to sending appropriate price signals to customers regarding their electricity usage.

To be cost reflective, a retail tariff has to reflect the overall cost of supplying electricity, and also variations in the cost of supplying electricity due to the quantity of energy demanded (e.g. the cost to supply electricity increases in times of peak demand). Therefore, to determine fully cost reflective tariffs, both the level of the overall tariff and the structure of the tariff over time need to be considered.

In this section, the Authority calculates the overall level of cost reflective tariffs, taking into account the different elements of the retail cost stack.

The Authority has also reviewed the number of tariff categories, and reviewed similarities in the structure of tariffs to determine whether any tariff categories can be amalgamated. The Terms of Reference also require the Authority to consider whether regulated tariffs for contestable large business customers should be phased out, giving consideration to the competitive nature of the market at the present time. The proximity of uniform tariffs to cost reflective levels may assist in determining how quickly these tariffs can be phased out, as well as providing an assessment of the ability of the market to deliver fair outcomes to customers.

7.2 Draft Report

In the Draft Report the Authority considered that, given the information available at that time, there was no justification for merging any tariff categories.

7.3 Public Submissions

Synergy

Synergy recommended the B1 tariff be removed, due to the fact it is a legacy tariff that is no longer promoted, has a customer base of approximately 550 accounts, and Synergy anticipates it will be unreasonably costly to implement billing service changes to ensure these customers are billed in a manner consistent with the *Code of Conduct for the Supply of Electricity to Small Use Customers.*

Horizon Power

Horizon Power emphasised the need for the Authority to consult it on any proposed changes to tariff classes, as Horizon Power applies the same uniform tariffs as Synergy.

Citelum Australia

Citelum Australia did not comment on the Authority's findings regarding the amalgamation or removal of tariffs. However, it did provide commentary on alternative approaches to street lighting tariffs, and suggested that the Authority look to the models adopted in Queensland and New South Wales.

7.4 Cost Reflective Tariffs

7.4.1 Background

This section details Synergy's cost reflective tariffs on an average revenue (c/kWh) basis. The Authority has not attempted a detailed tariff design in this inquiry. The tariffs in this section include only the costs of supplying electricity on an ongoing basis. Specific one-off charges, such as connection fees, should be recovered on a cost basis, as required.

Cost reflective tariffs (being by definition TEC-exclusive tariffs) are provided in Table 24. The TEC for 2012/13 onwards has yet to be gazetted by the government. In order to subtract the TEC from network charges, the Authority has used the assumptions adopted in the Authority's draft decision of Western Power's third access arrangement for the inquiry period from 2012/13 to 2015/16 (**AA3**).[73]

The cost reflective level of tariffs on a per kWh basis for Synergy's total tariff business is shown in Table 24 below. As previously noted, energy, capacity and network charges make up the largest share of costs, accounting for between 82 to 84 per cent of total cost depending on the year. Carbon prices account for 7 to 8 per cent of costs, retail operating costs 4 per cent and the retail margin approximately 3.5 per cent.

Table 24 Cost Reflective Tariff Breakdown, Total Tariffs (c/kWh, nominal) TEC Excluded 2012/13 to 2015/16

c/kWh	2012/13	2013/14	2014/15	2015/16
Wholesale Electricity Cost	[redacted]			
Networks				
Retail Operating Cost				
Renewable Energy Certificates				
Carbon				
Ancillary Services				
Market Fees				
Balancing				
Depreciation				
Retail Margin				
Total				

Source: ERA Analysis

With regard to the TEC-exclusive basis for cost reflective tariffs, the Authority believes that SWIS customers should not subsidise Horizon Power customers and that any shortfall in

[73] These assumptions are based on information from Western Power and from the most recent State Budget, indexed in line with inflation. For further information, see the Authority's website.

revenue to Horizon Power from the Uniform Tariff Policy should be funded through consolidated revenue. The tariffs in Table 24 are therefore provided on a TEC-exclusive basis. However, if the TEC continues to be funded through SWIS network tariffs, SWIS customers should be aware of the amount that the TEC-inclusive tariffs will be higher than the cost reflective tariffs.

Table 25 provides a breakdown showing the impact of the TEC on tariffs, where all other components are cost reflective. The inclusion of the TEC results in an increase in network costs, which flows through to the retail margin and the total tariffs.

Table 25 TEC Inclusive Tariff Breakdown (all other components being cost reflective) Total Tariffs (c/kWh, nominal) 2012/13 to 2015/16

c/kWh	2012/13	2013/14	2014/15	2015/16
Wholesale Electricity Cost	[redacted]			
Networks				
Retail Operating Cost				
Renewable Energy Certificates				
Carbon				
Ancillary Services				
Market Fees				
Balancing				
Depreciation				
Retail Margin				
Total				

Source: ERA Analysis

7.4.2 Allocation of Costs Across Customer Groups

To determine the cost to serve a customer on a particular tariff, all cost components, including network charges, capacity and energy costs, retail operating costs, etc, must be allocated across the various customer groups. In the case of energy costs, there are a number of ways of performing this allocation.

7.4.2.1 Allocation of Energy Costs

The Authority considered the following approaches when allocating Synergy's wholesale energy costs to customer categories.

- **Time-of-use average costing**. This method divides the time-of-use period into three categories: peak, off-peak and shoulder periods.[74] The average cost for each time-of-use period is derived based on the optimal dispatch of Synergy's contract portfolio using its total load profile at half-hourly intervals. Each customer group's consumption pattern is also summarised into the three time-of-use

[74] A peak period is defined as all trading periods commencing and ending between 7:00am and 10:00pm Monday to Friday and a shoulder period is defined as all trading periods commencing and ending between 7:00am and 10:00pm on weekends and public Holidays; with all other trading periods being defined as off-peak. (Synergy information #128)

periods. The energy costs for a customer group is the aggregation of the average price multiplied by the consumption quantity over the three time-of-use periods.

- **LRMC approach**, which calculates the amount it would cost a new electricity retailer to procure wholesale electricity for supply to a particular class of customer as a stand-alone load. The LRMC includes both energy and capacity costs and provides a cost benchmark for a load shape, which focuses on the composition of the demand but not the timing. Aggregating the stand-alone LRMC estimates across customer classes may ignore the benefits from economies of scale and the effect of a flatter aggregated load shape, leading to higher cost estimates.
- **Cost allocation by matching load type with a specific bilateral contract.** This approach assesses how much each type of customer contributes to Synergy's cost of procuring a particular contract. Under this approach, a customer class with less variable demand (e.g. major industry loads) would be able to access proportionally more low-price, base-load contract than a customer class with higher variable demand (e.g. residential customers), which could result in some artificial biases in cost allocation.

Authority's Assessment

Synergy applies the time-of-use average costing in assessing its profitability across various customer groups. Although the alternative methods for cost allocation have their merits, the Authority considers the time-of-use methodology outlined above is the most appropriate for the purpose of this inquiry. This methodology is closest to cost causation principle, and yet the simplest approach.

The Authority has therefore adopted the time-of-use average price approach. Half-hourly cost values are split into the three time-of-use periods whereby the average for each of the time-of-use period is calculated. These average costs are then applied equally to all customer groups.

7.4.2.2 Allocation of Capacity Costs

A second component of the wholesale electricity cost is the capacity cost that a retailer incurs in the WEM.

The WEM has a **RCM**, operated by the Independent Market Operator (**IMO**), for ensuring that adequate generation and demand side management (**DSM**) capacity is available to maintain reliability and security of electricity supply. Under the RCM, retailers can either secure adequate capacity bilaterally or purchase it from the IMO. The IMO sets the capacity requirement for the total market two years in advance, and assigns capacity credits to generation and to DSM capacity to meet the capacity requirement. The total assigned capacity credits are then matched by the capacity obligations allocated to each retailer by the IMO during the settlement process. Hence, a retailer will not know its exact capacity obligation until the IMO calls for payments.

Synergy's contract portfolio covers approximately 80 per cent of its capacity obligation in the WEM. The shortfall is met by transactions with the IMO. Synergy's total capacity cost, which it pays to either its contract partners or to the IMO, is allocated to each customer group.

The most appropriate allocation basis for capacity costs is the causer-pay principle, applied by identifying the respective contribution of each customer group to the retailer's

capacity obligation. The IMO determines a retailer's capacity obligation based on the demand of its load during specific trading intervals during which the highest system demand readings have been recorded.

The Authority has sought information from Synergy as to how it allocates capacity cost to various customer classes. Synergy believes the proportions of capacity costs allocated between customer groups should be dependent on the relevant load profiles. Given that Synergy does not have interval meter readings for all its customer groups, Synergy has engaged Data Analysis Australia to develop deemed load profiles.[75]

For the purpose of capacity allocation, Synergy applies a two-step approach. Firstly Synergy calculates an annual peak demand for each customer group based on the relevant energy consumption forecast. Certain tariff classes are then excluded from the calculation.[76] The total annual capacity cost is then allocated among those that remain.

The Authority has taken a different approach to that adopted by Synergy. The Authority takes note of the half-hour interval in which Synergy's forecast peak demand of its total load portfolio occurs, then notes the peak demand for each customer group in that half-hour interval. This ensures that each customer groups' peak is measured at the same time and at a time that is most likely to fall into the IMO's definition of the peak period.[77] Each customer group's contribution to the demand in this peak is then calculated. This contribution is only applied to that part of demand that is considered to be above average during the peak. Each customer group is then allocated capacity costs based on a combination of both their average overall use throughout the year and their contribution to the above average demand in the peak. This method ensures no tariff classes are excluded from paying for capacity, whilst those that contribute the most to above average demand during the peak are allocated costs accordingly.

The table below illustrates how Synergy's forecast capacity requirement for the 2012/13 financial year has been allocated across customer groups. It shows that 53 per cent of Synergy's capacity requirement is attributable to the A1 customer group (i.e. residential customers).

Table 26 ERA's Capacity Allocation for Synergy's Contracted Capacity in 2012/13

	Total Allocated Capacity (MW)	Total Allocated Capacity (%)		Total Cost
Non-Contestable Customers				
A1	2273	53%	$	460,078,228
SM1			$	15,572,519
B1	0	0%	$	98,211
C1	14	0%	$	2,859,387
D1	4	0%	$	735,863
K1	45	1%	$	9,035,281
L1	310	7%	$	62,750,735
R1	46	1%	$	9,353,009
Z1	24	1%	$	4,941,728
UMS (including W1)	11	0%	$	2,284,006

[75] DAA 2009 study.

[76] Tariffs B1 and Z1 are excluded

[77] http://www.imowa.com.au/n545.html

Contestable Customers			$	33,061,594
L3	163	4%	$	692,900
M1	3	0%	$	37,504,010
R3	185	4%	$	21,983,240
S1	109	3%	$	16,250,220
T1	80	2%	$	153,731,532
ECON	760	18%	$	39,392,428
PP	195	5%	$	33,061,594
Total Synergy	**4300**	**100%**	**$**	**870,324,893**

Source: ERA Analysis

Allocation of Network Costs

The network costs are a straight pass-through in accordance with the corresponding network tariff of each customer group. The network tariffs incorporated in this report reflect the Authority's draft decision regarding Western Power's third access arrangement released on 29 March 2012.

7.4.3 Cost Reflective Tariffs

The Draft Report recommended that the move towards efficient costs should be transitioned over a two year period.

A number of submissions have raised the issue that the two year transition period is too short.

Synergy submitted that it is unable to re-negotiate its contracts in two years to achieve efficient cost levels. The PUO also suggested that two years does not appear to be sufficient time to transition to efficient costs. Horizon Power expressed concern that two years is too short a period of transition from actual contract costs to a LRMC cost.

Authority's Assessment

The reason for the two year transition period in the Draft Report was to allow time for Synergy to adjust its contracts and operations to realign its cost with efficient costs. This was considered as the appropriate pragmatic implementation strategy.

However, the Authority has reconsidered this approach for the Final Report. Several submissions commented on the length of time necessary to transition to efficient costs, and the Authority recognises that any judgment on a sufficient transition time is inherently a subjective one and largely a policy issue. Given that the terms of reference require the Authority to determine efficient costs, the Authority has provided these for each of the four years of the period, and notes that any transition arrangement is a decision for government.

Consequently, the Authority has developed the efficient costs in each year of the inquiry period, including for the first two years. These costs are below Synergy's actual costs. The Authority believes that the tariffs should reflect these efficient costs, although the Authority acknowledges that Synergy's own actual costs may not immediately revert to these costs. This mimics the outcome of a competitive market, where tariffs are based on the cost that an efficient new entrant supplier will incur, and incumbent suppliers face the risk of not being able to recover costs that they are locked into.

Furthermore, the Authority notes that the tariffs for non-contestable customers in the first two years are set below both the actual cost and the efficient costs. As such, the decision to allow any transition period does not have any impact on customers.

The government currently provides a CSO payment to Synergy that covers the shortfall between the revenue recovered and the actual cost of supply. In this regard, Perth Energy states that:

> Perth Energy holds the view that the amount of any CSO payment made to Synergy as compensation for supplying non-contestable customers below the cost of supply should be based on the difference between the actual revenue received from that supply and the efficient costs of supply. Otherwise, Synergy will continue to focus its effort on rent seeking activity (trying to obtain more and more CSO funding) rather than on competitive activity to minimise cost of supply.

The Authority concurs with Perth Energy's conclusion that the CSO payment should be based on the efficient cost of supply. While this will reduce Synergy's profitability, it represents the outcome that is expected in a competitive market, and forms part of the operational risk for which Synergy is compensated for in its margin allowance.

As such, for the purposes of establishing efficient cost reflective tariffs, as required under the terms of reference, the Authority has not applied any transition period in its findings. However, the Authority notes that the matter of determining the glide path to transition current tariff levels to efficient cost reflective tariffs is beyond the scope of the terms of reference of this inquiry (although the Authority has provided some indicative price paths in Section 8.4.1.1).

The table below shows the cost reflective level for each of Synergy's regulated tariffs, as well as for the Z1 tariff.[78]

Table 27 Cost Reflective Tariffs, Individual Tariffs (c/kWh, nominal) TEC Exclusive 2012/13 to 2015/16

Tariff	Tariff Description	2011/12 Actual	2012/13 Budget	2012/13 Budget + Carbon[79]	2012/13	2013/14	2014/15	2015/16
	Non-contestable							
A1	Residential	22.34	23.12	25.37	28.78	28.83	29.40	30.83
B1	Residential water heating	14.25	14.74	17.00	18.77	18.81	19.26	20.21
C1	Non-profit organisations	22.26	22.77	25.02	25.47	25.54	25.80	27.01
D1	Charitable residential	18.79	17.91	20.16	24.87	25.14	25.37	26.05
K1	Mixed commercial & residential	23.75	24.58	26.83	27.54	27.61	28.07	29.29
L1	Low voltage supply (<50 MWh)	24.02	24.86	27.11	27.95	28.00	28.45	29.71
R1	Time-of-use tariff (<50 MWh)	17.37	17.97	20.23	30.12	30.23	30.63	32.03

[78] This is calculated as a by-product of calculating the regulated tariffs.

[79] Based on the Authority's estimate of Synergy's carbon costs.

W1	Traffic lights	22.91	25.66	30.18	24.56	24.73	25.05	26.62
Z1	Street lights	36.50	34.68	35.12	38.54	38.92	39.76	41.19
UMS	Unmetered supply	22.91	24.06	30.18	20.01	20.05	20.35	21.45
	Contestable							
L3	Low voltage supply (>50 MWh)	29.04	30.90	31.74	26.84	26.92	27.41	28.61
M1	General supply (high voltage)	25.21	26.02	29.64	26.39	27.65	28.21	28.99
R3	Time-of-use tariff (>50 MWh)	23.25	24.53	26.04	21.91	21.87	22.25	23.42
S1	Low/med voltage time-of-use	19.33	21.26	23.94	21.93	21.83	22.14	23.27
T1	High voltage time-of-use	18.56	20.79	22.86	20.61	20.53	20.81	21.88
	Average across all tariffs	**22.93**	**23.77**	**25.89**	**27.74**	**27.78**	**28.32**	**29.74**

Source: ERA Analysis

Table 28 shows the differences (in c/kWh) between the 2012/13 State Budget tariffs (shown in terms of CPI, and in terms of CPI plus carbon pass through[80]) and the cost reflective tariffs in the same year. The cost reflective tariffs exclude the TEC. Adding the TEC back in would increase the cost reflective tariffs by an average of approximately 1.64 c/kWh.

Table 28 Assumed Budgeted Tariffs versus Cost Reflective Tariffs (c/kWh) TEC Exclusive 2012/13

Tariff	Tariff Description	2011/12 Actual	2012/13 Budget	2012/13 Budget + Carbon	2012/13 Cost Refl.	2013/14 Cost Refl.	2014/15 Cost Refl.	2015/16 Cost Refl.
	Non-contestable							
A1	Residential	22.34	23.12	25.37	30.42	30.50	31.11	32.60
B1	Residential water heating	14.25	14.74	17.00	20.20	20.27	20.75	21.75
C1	Non-profit organisations	22.26	22.77	25.02	27.10	27.21	27.51	28.77
D1	Charitable residential	18.79	17.91	20.16	26.50	26.81	27.08	27.81
K1	Mixed commercial & residential	23.75	24.58	26.83	29.18	29.28	29.78	31.05
L1	Low voltage supply (<50 MWh)	24.02	24.86	27.11	29.59	29.67	30.17	31.48
R1	Time-of-use tariff (<50 MWh)	17.37	17.97	20.23	31.55	31.69	32.12	33.57

[80] Based on the Authority's estimate of Synergy's carbon costs.

W1	Traffic lights	22.91	25.66	30.18	26.19	26.40	26.76	28.38
Z1	Street lights	36.50	34.68	35.12	40.17	40.59	41.47	42.95
UMS	Unmetered supply	22.91	24.06	30.18	21.64	21.72	22.06	23.21
	Contestable							
L3	Low voltage supply (>50 MWh)	29.04	30.90	31.74	28.48	28.59	29.12	30.37
M1	General supply (high voltage)	25.21	26.02	29.64	28.02	29.32	29.92	30.75
R3	Time-of-use tariff (>50 MWh)	23.25	24.53	26.04	23.64	23.63	24.07	25.29
S1	Low/med voltage time-of-use	19.33	21.26	23.94	23.63	23.57	23.93	25.11
T1	High voltage time-of-use	18.56	20.79	22.86	22.36	22.32	22.65	23.77
	Average across all tariffs	**22.93**	**23.77**	**25.89**	**29.37**	**29.45**	**30.04**	**31.50**

Source: ERA Analysis

Overall, on a TEC-inclusive basis, the 2012/13 Budget tariffs, including carbon, are 11.9 per cent below their aggregated cost-reflective level. However, there is substantial variation between tariffs. On a TEC exclusive basis, contestable tariffs are all above their respective cost-reflective levels, while non-contestable tariffs are below cost. Adding back in the effect of the TEC would, eliminate the remaining difference between the estimated actual tariffs and cost reflective tariffs for contestable customers. However, there would still be an under recovery for non-contestable tariffs (including residential customers).

Non-contestable tariffs (households and small businesses) are further away from cost reflectivity due to two main reasons:

- these tariff classes generally have higher cost structures due to their load profiles, or the way in which they consume electricity; and
- contestable tariffs had a greater rate of increase in 2011 than households and small businesses, bringing them closer to cost reflective levels. Larger businesses experienced increases of between 13 per cent and 29 per cent (depending on the tariff), whereas households and small businesses experienced increases of 5 per cent.

7.5 Amalgamation of Tariffs

7.5.1 Background

Amalgamation (or removal) of tariffs for non-contestable customers is recommended where the tariff no longer serves the purpose for which it was originally designed (strategic or policy objective not being met), is economically inefficient (requires subsidisation or causes market distortions), or can be replaced with alternative pricing arrangements, resulting in overall net cost savings.

The following tariffs have been identified as candidates for amalgamation or removal:

- B1 Tariff: Residential off-peak hot water heating. This tariff was introduced some decades ago to facilitate cheaper water heating costs for those customers who were unable to access alternative fuel sources such as reticulated natural gas. The B1 tariff requires a separate meter with a load control timer that activates between 11pm and 6am, and was designed to take advantage of cheaper overnight base load electricity. There are fewer than 500 B1 customers with no potential for growth in customer numbers due to tightening greenhouse gas emission restrictions on electric storage hot water systems. The basis for examining the B1 tariff is that the retail operating costs for maintaining small numbers of low consumption tariff customers are likely to outweigh the benefits to the customer group, resulting in a cross-subsidisation.

- C1 Tariff: Special community service tariff for voluntary, non-profit organisations (community groups, youth groups, non-profits, fire & rescue groups). There are just over 2000 C1 tariff customers, with an average consumption of just over 16MWh per annum per connection. This tariff has been identified for removal with the potential for customers to shift to other business tariffs such as the L1 tariff or R1 tariff. The basis for examining the C1 tariff is that it may contain a subsidy, distorting market signals for efficient resource allocation. It may be better to provide a direct subsidy to such organisations rather than deliver a subsidy via discounted electricity.

- D1 Tariff: Special tariff for charitable or benevolent organisations providing residential accommodation (hostels, homes for the aged, emergency accommodation). There are currently 75 D1 tariff customers, with an average consumption 122.5 MWh per annum per connection. Again, this tariff may contain a subsidy, which may be better delivered directly. Many of these customers are large enough to be contestable.

7.5.2 Authority Assessment

7.5.2.1 B1 Tariff (Residential Off-Peak Water Heating)

B1 tariff customers are all A1/B1 dual tariff customers, and are currently billed via 'collective invoicing' (a single invoice that includes both tariffs).

Synergy advises that the current method of billing the B1 tariff on a 'collective bill' is not currently compliant with the *Code of Conduct*, and that the investment to upgrade the customer information and billing systems to enable compliance is likely to be prohibitive for a small portfolio of small-use customers. Synergy no longer promotes the B1 tariff, is implementing measures for alternative billing arrangements in the short term, and ultimately seeks withdrawal of the B1 tariff.

Following publication of the Authority's Draft Report, Synergy has subsequently provided information to the Authority as to the size of the investment required to upgrade Synergy's billing and information systems to ensure compliance with the Code of Conduct for the B1 tariff customers. The Authority has determined that this investment is not efficient and cannot be justified for the relatively low and declining numbers of B1 tariff customers. As such, the Authority considers that the B1 tariff should be merged with the A1 tariff**.**

7.5.2.2 C1 Tariff (Special Community Services) and D1 Tariff (Charitable Residential)

Analysis of the C1 tariff indicates that the estimated cost reflective price of this portfolio is significantly less than the L1 and L3 tariff classes and therefore not suitable to amalgamate with either of these tariffs. The C1 tariff has a similar cost profile to the R1 time-of-use portfolio, but is higher than the R3 portfolio.

Similarly, the D1 tariff has an estimated cost reflective price that is substantially less than either the L1 or L3 tariffs. The D1 tariff has an estimated cost profile lower than that of R1 and higher than that of R3.

It is noted that Recommendation 4 of the OoE's *Electricity Retail Market Review 2009*, stated that

> The Community and Charitable Organisation Tariffs (C1/C2 and D1/D2 Tariffs) should be removed from 2009/10, with assistance instead provided by direct Community Service Obligation payments.

However, the ERA's analysis shows that the load profiles and therefore the cost to serve the C1 and D1 portfolios, is sufficiently different from the general business tariffs to warrant separate treatment of these customer groups. The Authority does not recommend amalgamation of either the C1 or D1 tariffs with other regulated tariffs.

Instead, the Authority recommends that the C1 and D1 tariffs be retained and moved to cost reflective levels. It is noted that larger C1 or D1 customers do have the option of seeking market based contracts.

7.6 Findings

1. The Authority considers that the B1 Residential Hot Water Tariff should be merged with the A1 Tariff. There is no justification for merging any other tariff categories at this stage.

8 Tariff Impacts

In accordance with the Terms of Reference, the Authority has determined the efficient cost reflective tariff for each customer category (i.e., Terms of Reference 1-3).

The Terms of Reference do not require the Authority to address equity issues that may arise in the implementation of cost reflective tariffs. Equity considerations are generally a matter of government policy. The role of the Authority is not to set tariffs but rather to provide independent advice to the government to enable it to make decisions on regulated tariffs. Therefore, this section sets out the Authority's assessment of the impacts of cost reflective tariffs on different types of customers, Synergy and government finances.

8.1 Draft Report

The Authority made a number of recommendations in relation to tariff impacts in the Draft Report:

- The Authority considered two years to be an appropriate period for Synergy to achieve the efficiency gains necessary to move to cost reflective tariffs.
- The Authority recommended that Synergy take steps to reduce wholesale electricity costs and retail operating costs over this two year period.
- The Authority recommended that the subsidy to Horizon Power be provided by a CSO rather than the TEC, and noted that this CSO would be partially offset as a result of moving to cost reflectivity.

8.2 Public Submissions

Public Utilities Office (Department of Finance)

The PUO suggested that the method adopted by the government to fund the TEC is a decision for the government. Given that the Authority's proposed change would have a significant budget impact on the government, the PUO requested that the Authority include information in the report based on the government's current policy.

It also stated that the impacts of the Authority's recommendations upon Synergy's financial sustainability were not sufficiently detailed in the Draft Report, but noted that this is confidential information and that it is not necessarily appropriate to disclose this information publicly. Consequently, the PUO requested that the Authority analyse Synergy's financial stability, including the impact of select scenarios on Synergy's profitability and cash flow, with the intent of providing the information confidentially to the government.

Western Power

Western Power supported the Authority's recommendation for the TEC to be removed, and for the uniform tariff policy to be supported transparently via a CSO.

Western Australian Council of Social Service Inc. (WACOSS)

WACOSS emphasised the need for targeted improvements in concessions for low income households, in order to offset further price shocks and ensure concessions are provided to those most in need. It stated that maintaining artificially low electricity prices by means of an across-the-board government subsidy to all customers is neither cost effective nor desirable in terms of social policy, as it subsidises those who can easily afford to pay for their consumption, and provides a greater subsidy to those who consume more energy without regard for need.

Additionally, WACOSS supported the Authority's recommendation for the TEC to be removed, but noted the importance of retaining uniform tariffs throughout Western Australia, stating that the cost of the uniform tariff policy should be borne fairly and equitably by all Western Australians out of consolidated government revenue.

Energy Supply Association of Australia (esaa)

esaa supported the Authority's proposal to transfer the burden of funding the TEC from SWIS customers to the government via a CSO, noting that such an approach would be more equitable, efficient and transparent.

ERM

ERM expressed support for the removal of the TEC, and the provision of a subsidy via a CSO.

8.3 Principles

In assessing the impacts of cost reflective tariffs, it is first necessary to establish the cost reflective tariffs for different customer categories, and to identify how far actual costs are from cost reflective levels. The methodology applied by the Authority, and outcomes from this process are detailed in the previous chapters.

Having determined the cost reflective tariffs, it is possible to identify the price impacts on different customers of moving to cost reflective tariffs. Cost reflective prices are economically efficient, and so send the correct price signals to customers, rather than distorting prices away from cost reflective levels to achieve particular welfare objectives. As a consequence, it is preferable to use separate grants and targeted subsidies to assist particular customers, resulting in transparent and cost reflective pricing for all electricity users.

The Authority supports the positions of the Council of Australian Governments (**COAG**), and the Ministerial Council on Energy[81], who have supported the principle that social welfare and equity objectives should be met through clearly specified and transparently funded State or Territory community service obligations[82] that do not materially impede competition.

[81] http://www.coag.gov.au/coag_meeting_outcomes/2009-07-02/docs/energy_market_agreement.pdf

[82] A Community Service Obligation arises when a government specifically requires a public enterprise to carry out activities relating to outputs or inputs which it would not elect to do on a commercial basis, and which the government does not require other businesses in the public or private sectors to generally undertake, or which it would only do commercially at higher prices.

In this regard, the following principles apply to economically efficient electricity tariffs:

- Cost reflective tariffs send appropriate price signals to customers.
- Moving away from cost reflective tariffs has costs, in that it distorts price signals. It can also be an inefficient approach to delivering financial assistance to those who need it.
- Administrative cost should be minimised. In cases where the cost of addressing an equity issue through an adjustment to tariffs away from cost reflectivity is less than addressing it through alternative mechanism, it may be appropriate to deliver a subsidy via the tariff. However, in such cases, transparency of the subsidy should be maintained.

The social impacts upon individual consumers caused by moving from the current prices to cost reflective prices will depend upon the size of the customer's electricity account, and other factors affecting affordability such as the customer's income and other financial commitments.

8.4 Impacts on Customers

Given the diversity of customers in many tariff classes, it can be difficult to illustrate the impact of moving to cost reflective tariffs. This is because the 'average bill' may not represent the electricity usage of many customers in that tariff class. For instance, for some businesses utility bills may not be a large operating cost (compared to say; wages, freight, or stock costs) and so electricity price changes may have a very small impact on these consumers. For other businesses, utility bills may be a large component of operating costs, and hence the price increases will have a greater impact in their operating budget.

Furthermore, there is a wide spread in business customer usage. As such, average bill impact analysis is of little use for non-residential customers. This section will therefore focus on the impacts on residential customers. Using an 'average bill' remains a common way of illustrating impacts on residential customers.

8.4.1 Residential Customers

8.4.1.1 Background

- As detailed in the introduction to this report, real residential electricity prices in Perth (that is, adjusted for inflation) have until recently, in contrast to other capital cities, remained largely static over the past two decades. If electricity prices are to move to cost reflective levels (and are therefore more comparable with those in other states), it is appropriate to consider the impact of this transition on low income customers and those experiencing financial hardship.

Table 29 below shows the likely impact on an average sized household bill of moving from Synergy's current tariffs in 2011/12 to cost reflective tariffs in 2015/16.

The average bill increases are calculated based on the following assumptions:

- 2012/13 bills are based on an increase in existing tariffs as published in the 2012/13 State Budget Papers, including full pass through of the carbon tax; any increases thereafter are spread evenly over the remaining three years, as provided here by the Authority for illustrative purposes;
- average annual consumption of 6,208 kWh (the level in 2011/12); and
- Synergy expects average household consumption to decline over the period. For the purpose of determining impacts on customers, the Authority has calculated the bill impacts assuming households will continue to consume the same amount of electricity as in 2011/12. If average household consumption decreases (either as a result of customers choosing more energy efficient technologies, or simply choosing to be more frugal with electricity usage); this will offset the impact of price increases.

Note that the cost reflective tariffs do not contain the TEC. The effect of removing the TEC is to decrease cost reflective tariffs, and save households between $108 and $116 per average bill.

The table below shows the average annual bill impact to a residential customer, when the tariffs are steadily moved towards cost reflective tariffs. This is achieved by moving the tariff to the budget 3.5% plus full carbon cost pass-through in 2012/13, and from then onwards, the tariffs increase at equal increments each year to achieve full cost reflectivity in 2015/16.[83]

Table 29 Bill Impacts: Estimated Average Annual Bill for a Residential Customer, TEC Exclusive 2011/12 to 2015/16

			Forecasts			
	Tariff (GST inclusive)	**2011/12 Average Bill**	**2012/13**	**2013/14**	**2014/15**	**2015/16**
A1	Residential	1,525	1,733	1,849	1,973	2,005
	Annual change in Average Bill		207	116	124	132

Source: ERA Analysis

Synergy has a number of existing programmes to assist vulnerable customers and those experiencing financial hardship. Concessions are available to low income customers, those with dependent children, and those eligible for an air-conditioning allowance. The Hardship Utilities Grants Scheme (**HUGS**) assists customers experiencing payment difficulties to access financial counselling, and alternative payment arrangements, and waivers of debts, fees and charges can be granted where appropriate. A Hardship Efficiency Programme (**HEP**) also assists customers experiencing hardship with energy usage advice and appliance upgrades.

[83] It should be noted that the Government sets electricity retail tariffs, and the price path shown here is for illustrative purposes only. The actual movement in tariff, year on year, will be the Government's decision.

8.5 Impacts on Synergy and Government

8.5.1 Background

The following section considers the financial impact on Synergy of introducing cost reflective tariffs and removing the TEC.

The Authority notes that a transition to cost reflective tariffs is likely to have an impact on Synergy's business, in terms of revenue, credit management, customer behaviour and market share, but has not attempted to quantify these in terms of financial impacts. (For example, it is beyond the scope of this inquiry to quantify the impact of demand elasticity.) In the context of the cost reflective tariffs determined in previous chapters, the Authority has noted a number of potential impacts for Synergy arising from the introduction of cost reflectivity, with regard to both Synergy's non-contestable and contestable customers.

8.5.2 Synergy's Revenue Requirement

Synergy's efficient revenue requirement is shown in Table 30 below on a TEC exclusive basis.

Table 30 Synergy's Total Electricity Efficient Revenue Requirement ($m, nominal) TEC Exclusive 2011/12 to 2015/16

	2011/12	2012/13	2013/14	2014/15	2015/16
Energy / Capacity	[redacted]				
Networks					
Cost to Serve					
RECS					
Carbon					
Ancillary Services					
Market Fees					
Balancing					
Depreciation					
Retail Margin					
Total					

Source: ERA Analysis, includes market-based contracts.

Table 31 Synergy's Total Electricity Revenue Requirement Based on Actual Projected Costs ($m, nominal) TEC Exclusive 2011/12 to 2015/16

	2011/12	2012/13	2013/14	2014/15	2015/16
Energy / Capacity	[redacted]				
Networks					
Cost to Serve					
RECS					
Carbon					
Ancillary Services					
Market Fees					
Balancing					
Depreciation					
Retail Margin					
Total					

Source: ERA Analysis, includes market-based contracts.

The difference between Synergy's forecast actual costs and the revenue requirement based on efficient costs (as presented in Table 30 above) are shown in Table 32. Under efficient cost reflective tariffs and market based contracts, by 2015/16 Synergy's forecast actual costs are anticipated to be [redacted] million higher than the forecast efficient costs.

Table 32 Differences Between Synergy's Efficient Revenue Requirement and Actual Revenue Requirement ($m, nominal) TEC Exclusive 2011/12 to 2015/16

	2011/12	2012/13	2013/14	2014/15	2015/16
Energy / Capacity	[redacted]				
Networks					
Cost to Serve					
RECS					
Carbon					
Ancillary Services					
Market Fees					
Balancing					
Depreciation					
Retail Margin					
Total					

Source: ERA Analysis includes market-based contracts.

The Authority emphasises that the function of this inquiry is to determine Synergy's efficient cost-reflective tariffs, and that as part of this analysis it has been necessary to consider the cost of procuring wholesale energy from an efficient new generator (or from an incumbent generator matching the price of a new competitor in the market).

It is recognised by the Authority that incumbent operators may be advantaged or disadvantaged where the efficient price of wholesale energy is equal to the price for which

it may be procured by a new entrant retailer.[84] Existing generation and procurement decisions made within the WEM will determine whether or not the efficient new entrant price is advantageous for any operator. However, additional costs above that efficient new entrant price should not be passed through to consumers as they are, by definition, not efficient costs.

8.5.3 Impacts on Government

The difference between Synergy's forecast actual costs and the revenue requirement based on efficient costs (as presented in Table 30 above) are shown in Table 32. Under efficient cost reflective tariffs, by 2015/16, Synergy's forecast actual costs are anticipated to be [redacted] million higher than forecast efficient costs. Hence the impact of the Authority's recommendations on government depends upon whether Synergy is able to reduce its costs to efficient costs by 2015/16, or whether it would face losses when out-competed by a new entrant.

The difference between the revenue recovered from cost reflective tariffs and actual tariffs that Synergy charges its customers, is covered by government funded CSO payments. The Authority considers that the CSO payments should be based on the difference between revenue and efficient costs, rather than the difference between revenue and the actual costs Synergy incurs. If Synergy cannot achieve the cost reductions required to meet the efficient level of costs, the government dividend will be impacted.

The expected tariff increases in 2012/13 and the Authority's recommended cost reductions both have the impact of reducing the financial loss to government from Synergy's regulated business.

Table 33 below shows the financial impact on the government under two scenarios, with each scenario presented on a TEC inclusive and TEC exclusive basis. The two scenarios are based on Synergy charging cost reflective tariffs from 2013/14 onwards, and Synergy steadily increasing the tariffs to achieve cost reflectivity by 15/16.

In each scenario, the government's announced tariff changes for 2012/13 has been incorporated. Each scenario is described below.

Scenario 1: Impact on Government when Tariffs move to cost reflective levels from 2013/14

Under this scenario, the tariffs have been adjusted in each year following 2012/13 to reflect the Authority's finding on cost reflective tariffs. That is, for each year following 2012/13, the tariffs are set at a level that would recover Synergy's efficient cost.

With regard to Synergy's cost, this scenario assumes that it is able to meet its efficient cost target immediately, from 2012/13 and for every year after that.

This is the optimal scenario which represents the Authority's recommendation. Under this scenario, government does not have to 'top-up' payments to Synergy to ensure that Synergy earns a reasonable return on its operations.

[84] For instance, the Authority notes the large asset write downs for generators in the National Electricity Market (NEM) due to the introduction of the carbon tax and considers that a similar situation would occur here, although contractual arrangements mean that the generators have been able to transfer the losses through to the retailers.

However, as recommended by the Authority, the government contributes towards the TEC subsidy, which is no longer collected through efficient cost reflective tariffs. If the government continues to collect the TEC subsidy payment through tariffs, it will have no outgoings at all.

Variation to Scenario 1: Under this scenario, the tariff adjustment to cost reflectivity remains the same as outlined above. However, with regard to Synergy's cost, this scenario assumes that Synergy is not able to meet its efficient cost target, and continues to operate based on costs as per its current estimate (which is higher than the efficient cost determined by the Authority). This means that there is a mismatch between revenue recovery and costs for Synergy. That is, whereas, the revenue recovered is based on efficient costs, its actual costs are higher and as a result, Synergy will incur a loss.

Accordingly, the government's net payments to Synergy will be higher than what it would be otherwise. In addition, the government will need to provide the TEC subsidy, provided it is removed from tariffs. If TEC is not removed from the tariffs, customers will continue to face the additional charge, saving the government from paying this subsidy.

Scenario 2: Impact on Government when Tariffs steadily move towards cost reflectivity

Under this scenario, the tariffs have been adjusted in each year following 2012/13 to steadily move towards cost reflective tariffs in the last year of the review period 2015/16 (referred to as 'glide path'). This glide path is derived by achieving the same rate of increase in each year of the three years following 2012/13.

With regard to Synergy's cost, this scenario also assumes that it is able to meet its efficient cost target immediately, from 2012/13 and for every year after that.

Under this scenario, due to the steady increase in tariffs (as opposed to an immediate one) to achieve cost reflectivity, the government needs to continue supporting Synergy, but to a lesser extent each year, and eventually providing no support, as the tariffs reach cost reflectivity in 2015/16.

However, as recommended by the Authority, the government contributes towards the TEC subsidy, which is no longer collected through efficient cost reflective tariffs. If the government continues to collect the TEC subsidy payment through tariffs, it will not have any TEC outgoings.

Variation to Scenario 2*:* Finally, under this scenario, although the tariffs adjustment remains as described above (that is, tariffs increase in accordance with the glide path), this variation of the scenario assumes that Synergy is not able to meet its efficient cost target, and continues to operate based on costs as per its current estimate (which is higher than the efficient cost determined by the Authority).

Under this scenario, there is also a mismatch between revenue recovery and costs for Synergy. That is, whereas, the revenue recovery is steadily moving towards efficient cost reflective levels, its actual costs remain higher for the period of the review. As a result, Synergy will incur the greatest loss under this scenario.

Accordingly, the government's net payments to Synergy will be higher than what it would be otherwise. In addition, the government will need to provide the TEC subsidy, provided

it is removed from tariffs. If TEC is not removed from the tariffs, customers will continue to face the additional charge, saving the government from paying this subsidy.

Table 33 Financial Impacts on Synergy and Government ($m) 2012/13 - 2015/16

Scenario 1 (no TEC in Tariffs)	*Costs* *Efficient*		*Tariffs* *CRT*		*Transition* *Immediate*				
	2011/12	2012/13	Δ in Tariff	2013/14	Δ in Tariff	2014/15	Δ in Tariff	2015/16	Δ in Tariff
CSO	-349.66	-146.81	13%	-	7%	-	2%	-	5%
TEC		-186.60		-190.80		-195.70		-201.50	
Net Gov't	-349.66	-333.41		-190.80		-195.70		-201.50	

Scenario 1 (TEC in Tariffs)	*Costs* *Efficient*		*Tariffs* *CRT*		*Transition* *Immediate*				
	2011/12	2012/13	Δ in Tariff	2013/14	Δ in Tariff	2014/15	Δ in Tariff	2015/16	Δ in Tariff
CSO	-349.66	-276.66	13%	-	14%	-	2%	-	5%
TEC		-		-		-		-	
Net Gov't	-349.66	0.00		0.00		0.00		0.00	

Scenario 1 (a) (no TEC in Tariffs)	*Costs* *Actual*		*Tariffs* *CRT*		*Transition* *Immediate*				
	2011/12	2012/13	Δ in Tariff	2013/14	Δ in Tariff	2014/15	Δ in Tariff	2015/16	Δ in Tariff
CSO	-349.66	-199.96	13%	-48.55	7%	-66.30	2%	-57.94	5%
TEC		-186.60		-190.80		-195.70		-201.50	
Net Gov't	-349.66	-386.56		-239.35		-262.00		-259.44	

Scenario 1 (a) (TEC in Tariffs)	*Costs* *Actual*		*Tariffs* *CRT*		*Transition* *Immediate*				
	2011/12	2012/13	Δ in Tariff	2013/14	Δ in Tariff	2014/15	Δ in Tariff	2015/16	Δ in Tariff
CSO	-349.66	-329.81	13%	-48.55	14%	-66.30	2%	-57.94	5%
TEC		-		-		-		-	
Net Gov't	-349.66	-329.81		-48.55		-66.30		-57.94	

Scenario 2 (no TEC in Tariffs)	Costs Efficient		Tariffs CRT		Transition Glide				
	2011/12	2012/13	Δ in Tariff	2013/14	Δ in Tariff	2014/15	Δ in Tariff	2015/16	Δ in Tariff
CSO	-349.66	-146.81	13%	-64.06	4%	-6.28	5%	-	5%
TEC		-186.60		-190.80		-195.70		-201.50	
Net Gov't	-349.66	-333.41		-254.86		-201.98		-201.50	

Scenario 2 (TEC in Tariffs)	Costs Efficient		Tariffs CRT		Transition Glide				
	2011/12	2012/13	Δ in Tariff	2013/14	Δ in Tariff	2014/15	Δ in Tariff	2015/16	Δ in Tariff
CSO	-349.66	-276.66	13%	-153.98	6%	-53.36	7%	-	7%
TEC		-		-		-		-	
Net Gov't	-349.66	-276.66		-153.98		-53.36		-	

Scenario 2 (a) (no TEC in Tariffs)	Costs Actual		Tariffs CRT		Transition Glide				
	2011/12	2012/13	Δ in Tariff	2013/14	Δ in Tariff	2014/15	Δ in Tariff	2015/16	Δ in Tariff
CSO	-349.66	-199.96	13%	-112.62	4%	-72.58	5%	-57.94	5%
TEC		-186.60		-190.80		-195.70		-201.50	
Net Gov't	-349.66	-386.56		-303.42		-268.28		-259.44	

Scenario 2 (a) (TEC in Tariffs)	Costs Actual		Tariffs CRT		Transition Glide				
	2011/12	2012/13	Δ in Tariff	2013/14	Δ in Tariff	2014/15	Δ in Tariff	2015/16	Δ in Tariff
CSO	-349.66	-329.81	13%	-202.54	6%	-119.66	7%	-57.94	7%
TEC		-		-		-		-	
Net Gov't	-349.66	-329.81		-202.54		-119.66		-57.94	

Source: ERA Analysis

The Authority has recommended that the TEC be recovered through a CSO rather than a charge on SWIS distribution customers. Under this assumption, the government would be required to fund an additional CSO to cover the TEC. Should the TEC be retained in distribution network charges, this would amount to approximately 1.58 c/kWh (nominal) in 2015/16.

8.6 Findings

1. The Authority recommends that the subsidy to Horizon Power be provided by a CSO rather than the TEC.

9 Regulation of Tariffs

9.1 Background

In considering the regulatory framework for Synergy's tariffs, the Authority has, in accordance with the terms of reference, considered the issue of whether regulated tariffs should continue to be made available to contestable business customers:

> Terms of Reference 4: consider whether regulated tariffs for contestable large business consumers should be phased out, with reference to the competitive nature of this segment of the electricity market; and
>
> Terms of Reference 5: if regulated, large contestable tariffs are to be phased out, provide recommendations on which tariffs should be phased out and over what timeframe.

The Authority has also considered how Synergy's tariffs should be regulated in the future. Section 9.5.2 sets out the Authority's assessment and recommendations on how cost reflective tariffs should be monitored and reviewed.

9.2 Draft Report

In its Draft Report the Authority made a number of recommendations on the future regulation of tariffs. Noting that the second and third recommendations have been retained in this Final Report, these were as follows:

- The Authority recommended that regulated tariffs be retained for all contestable customers through to 2015/16 and re-assessed at the next review.
- The Authority recommended that the next inquiry into the efficiency of Synergy's costs and electricity tariffs be conducted in 2014/15 rather than at the end of the four year review period, to allow for a timely assessment of changes in Synergy's carbon cost.
- The Authority recommended that if there are significant changes to economic conditions, a mid-period review be undertaken.

9.3 Public Submissions

Synergy

Synergy agreed with the Authority's recommendation that regulated tariffs be retained for all contestable customers through to 2015/16 and be re-assessed at the next review, and that an interim review be conducted in 2014/15 to address any impacts arising from Federal Government carbon policy.

However, Synergy proposed that, whilst it is appropriate for a methodology for calculating cost reflective tariffs to be agreed in advance, a number of parameters should be updated each year, and a new tariff cost stack calculation should reflect changes in:

- CPI and labour escalation rates;
- Renewable percentages;

- Non-controllable costs;
- Wholesale pass through costs;
- Negotiated carbon intensities in wholesale electricity supply agreements;
- Synergy's costs attributable to changes in load profiles, increased PV market penetration, contract price resets and the commencement of new supply contracts;
- IMO capacity attributable to changes in regulated price or SWIS demand;
- Capacity attributable to changes in the regulated tariff load shape; and
- Forecast balancing and STEM prices, attributable to the impact of the carbon tax, market surplus or shortfall, and fuel supply.

WACOSS

WACOSS commented that, in the event an appropriate concession framework is not in place by the end of the regulatory period, a glide path towards cost reflective pricing should be extended beyond 2015 out to 2020 to ease the effects of the transition upon households.

It noted the importance of certainty and transparency in electricity pricing and proposed a more formalised and transparent costing procedure with prices determined out to 5 years to enable consumers to plan ahead of time for any changes in the price of electricity. It does, however, note the need for a mechanism to respond to unforseen factors and allow prices to be reviewed if necessary at other points in the regulatory period.

Horizon Power

Horizon Power emphasised the necessity of being provided with adequate time to determine the impact of any changes to tariff classes or cost reflective levels, in the event that the government instructs the Authority to conduct a second inquiry within the regulatory period. It also noted the complexity of planning for and administering the removal of regulated tariffs, should this be recommended by the Authority at a later date.

Energy Supply Association of Australia (esaa)

essa supported the development of a fully competitive retail electricity sector in Western Australia, and emphasised the importance of moving to cost reflective pricing along with the unwinding of the current, non-transparent subsidies embedded in electricity tariffs.

ERM

ERM proposed the phasing out of all tariffs, moving to a fully competitive retail electricity market as soon as is feasible.

9.4 Removal of Regulated Tariffs for Contestable Customers

9.4.1 Background

All electricity customers connected to the SWIS who consume more than 50 MWh per annum (an average of 137 units a day) at an electricity supply address have a choice of electricity retailer.[85]

Customers who use more than 50 MWh per annum and less than 160 MWh per annum may choose to:

- pay the relevant regulated tariff offered by Synergy under the standard form contract; or
- negotiate a market based contract with either Synergy or another electricity retailer of their choice.

If a 50-160 MWh customer elects to move from a Synergy standard form contract / tariff to a market based contract (either with Synergy or another retailer) and then wishes to return to the relevant tariff after the expiry of the market based contract, then this is permissible under the Electricity Industry (Customer Contract) Regulations 2005.

Note that a Customer is defined under the Electricity Industry Act 2004 as "a customer who consumes not more than 160MWh per annum".

9.4.1.1 Current Tariffs for Contestable customers

The following tariffs are currently available for customers who consume greater than 50 MWh per annum:

- L3 Tariff: Business general supply.
- R3 Tariff: Business time-of-use.
- M1 Tariff: Large Business general supply high voltage.
- S1 Tariff: Large Business Demand low voltage.
- T1 Tariff: Large Business Demand high voltage.

L3 and R3 tariffs apply to a total portfolio of over 10,000 medium to large business customers. The L3 tariff is for customers who consume more than 50MWh per annum, and comprises a daily supply charge and declining block energy charges. The R3 tariff is for customers who consume more than 50MWh per annum and comprises a daily supply charge and peak / off-peak energy charges. The breakdown by tariff is presented in Table 34 below:

[85] There exists no electricity consumption threshold for contestability outside the SWIS, and so all electricity customers outside the SWIS are free to choose their retailer. However, in practice most customers are limited to Horizon Power due to a lack of alternative retailers.

Table 34 Average Consumption in 2010/11 for L3 and R3 Customers

Tariff	No. Customers	Average Consumption 2011 (MWh)
L3	5,984	109
R3	4,643	154

Source: Synergy.

Note: Customer numbers and consumption are based on an average across the financial year and may not match year end data.

M1, S1 and T1 tariffs apply to a total portfolio of 302 very large business customers who generally have unusual peak demand profiles as well as a high average daily consumption. The M1 tariff is for larger customers connecting at high voltage, and comprises a fixed daily charge and declining block energy charges. The S1 tariff is for larger customers connecting at low voltage and comprises a minimum daily charge, a maximum demand charge, and peak / off-peak energy charges. The T1 tariff is similar to the S1 tariff, but for high voltage connection. The breakdown by tariff is provided in Table 35 below:

Table 35 Average Consumption in 2010/11 for M1, S1 and T1 Customers

Tariff	No. Customers 2010/11	Average Consumption 2011 (MWh)
M1 (high voltage)	30	381
S1 (low voltage)	202	1,573
T1 (high voltage)	70	4,244

Source: Synergy

Note: Customer numbers and consumption are based on an average across the financial year and may not match year end data.

9.4.2 Authority Assessment

The Authority believes that effective competition will provide a better discipline on prices, than any form of market intervention. However, any recommendation to remove price regulation must be based on an assessment of the effectiveness of the market, and its ability to provide competitive pressure on tariffs. As such, the Authority has undertaken an assessment of the contestable market in WA.

9.4.2.1 How Contestable is the Retail Market?

Information on market share for electricity retailers in Western Australia is difficult to obtain due to its commercially sensitive nature. However, the limited public data available suggests that the electricity market has been becoming more competitive over the past six years, with Synergy's share of electricity sales falling. The Office of Energy's review of Verve Energy in 2009[86] indicated that Synergy's share of electricity sold in the contestable market (more than 50 MWh per annum) decreased from 90 per cent in 2006 to 66 per cent in 2009. Synergy's 2010/11 annual report indicated that in 2010/11, Synergy's share of the contestable electricity market was 48 per cent.[87]

Ability of Customers to Negotiate a Fair Contract

- M1, S1, T1 tariff customers – These groups of customers have an average annual consumption significantly higher than 160 MWh. These customers incur significant expenditure in electricity usage each year. This high level of expenditure on electricity gives these customers reasonable buying power and the ability to negotiate a fair contract.

- L3 and R3 tariffs – The concern here is that the market may not be mature enough just yet to accommodate relatively small contestable customers, in terms of offering choice and a balance of bargaining power; i.e. will the customers be offered a 'take it or leave it' deal with no power to negotiate?

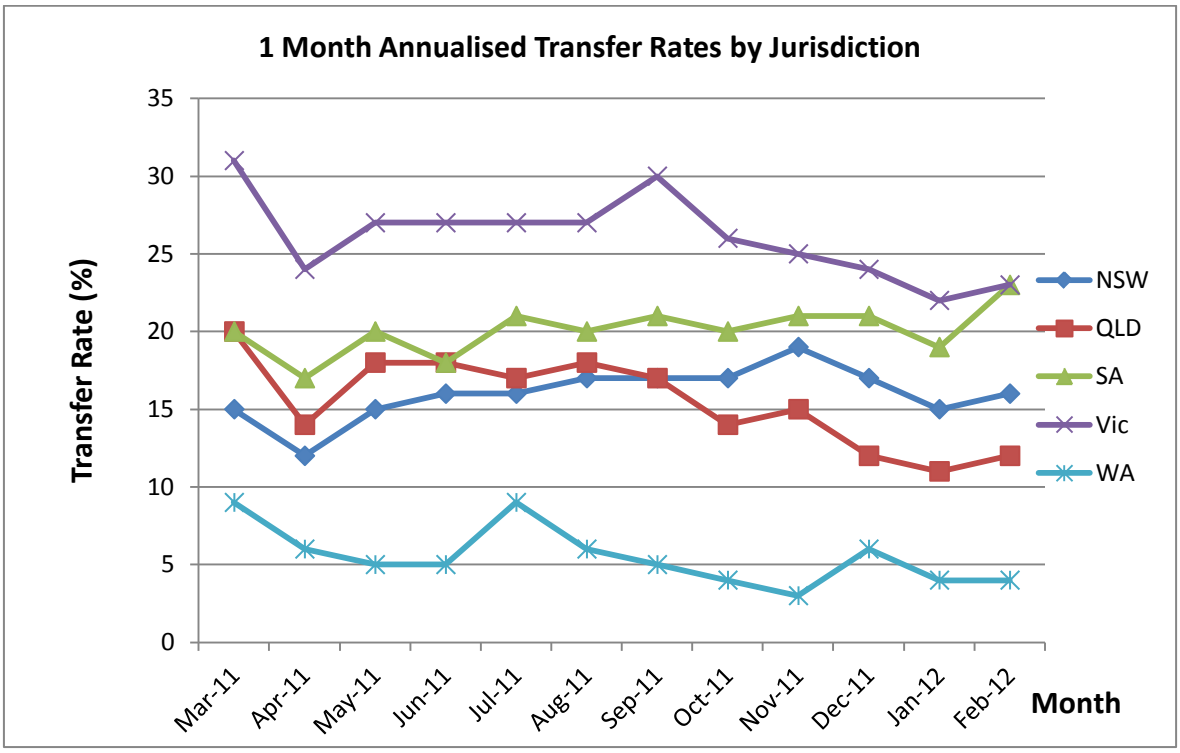
A significant barrier to retail competition in the past has been the regulated tariffs that were below cost reflective tariffs. However, in recent years, tariffs have increased to be at, or in some cases above, cost reflective levels for contestable customers.

Although the tariffs for contestable customers have reached cost reflective levels, the market has yet to evolve to reach effective competition. The following graph shows the customer churn rates for contestable customers in WA against the churn rate for contestable customers in the eastern states, on a comparable basis.

[86] Office of Energy (August 2009), *Verve Energy Review*.

[87] Synergy Annual Report 2010/11, p2.

Figure 7 One Month Annualised Customer Churn Rates



Source: AEMO data and ERA Analysis

The graph shows that the rate of churn amongst contestable customers in WA is much lower that the rate of churn in the eastern states. All the eastern states in the graph above have full retail contestability (**FRC**). That is, all customers in these states, including residential customers, are contestable.

Large Contestable Customers

SWIS customers with an average annual consumption of greater than 160 MWh have access to a reasonable number of active retailers of their choice, including Perth Energy, Alinta Sales and Premier Power.[88] Given the recent increases announced in the 2012/13 State Treasury Budget, their tariffs from 2012/13 virtually reflect efficient costs, even including TEC, and will no longer be subsidised. This is likely to encourage a greater level of activity in the market for these customers.

Given average annual expenditure on electricity for these customers, they are likely to hold significant countervailing powers to negotiate a fair contract with a retailer of their choice. The Authority also notes that tariffs for customers greater than 160 MWh are not regulated anywhere else in Australia. Given these conditions, the Authority recommends removal of regulated tariffs for M1, S1 and T1 customer categories.

[88] A complete list of all Licensed Retailers is available from the Authority's web site www.erawa.com.au

Small and Medium Contestable Customers

With regard to small to medium contestable customers (generally those consuming less than 160 MWh per annum), the Authority believes that, given that the tariffs are approaching cost reflective levels, and the low level of activity in the market, including relative churn rates of contestable customers, competition is unlikely to have achieved a level of competitiveness required to remove price regulation.

The Authority notes that as long as tariffs remain at or above cost reflective levels for contestable customers, the customers will have an incentive to seek better offers in the market over time, and the regulated tariffs serve the purpose of imposing a cap. Accordingly, the Authority recommends the continuation of regulated tariffs for all small to medium contestable customers (that is, customers other than M1, S1 and T1).

However, the Authority recommends that the effectiveness of competition is re-assessed again at the next review.

9.5 Regulatory Arrangements

9.5.1 Principles for the Regulatory Framework for Retail Prices

In developing recommendations for how retail electricity prices should be regulated in the future, the Authority has been guided by the principles set out below:

Principles for a Regulatory Framework for Electricity Retail Prices

Stability and certainty

- Customers and businesses value certainty and price stability. Longer periods between reviews provide for greater price certainty.
- The principles and methodology for setting prices need to be sound, consistent and predictable.

Cost reflectivity

- Sufficient flexibility is needed to adjust prices between price reviews to reflect changes in market conditions or costs that are outside the control of the regulated business.
- Tariffs should be able to be re-set periodically to reflect permanent shifts in costs; e.g.
  - improvements in cost efficiency, or reductions in input prices, to pass these on to customers; or
  - increases in input prices, to ensure that the service provider is able to recover its efficient costs.
- Determination of efficient cost reflective prices should be carried out by an independent body (i.e. independent of government, the service provider and major stakeholders).

Transparency

- The price setting methodology should be to be transparent.
- Any move away from cost reflective pricing by government should be transparent, fully costed, funded separately (rather than through price distortions) and underpinned by clear policy objectives.

Minimum administrative costs

- Administrative costs should be minimised. Regulatory reviews involve costs to businesses and the benefits of regulation should outweigh its costs.

9.5.2 Authority Assessment

9.5.2.1 Redetermination of Efficient Cost-Reflective Tariffs

This is the first Inquiry that the Authority has undertaken on electricity retail tariffs. The findings in this inquiry address the years 2012/13 to 2015/16. Any redetermination of cost-reflective tariffs, either within this period or from 2016/17 on, will require the Authority to be issued terms of reference and to conduct a subsequent inquiry at the instruction of the Treasurer.

The Authority notes that ensuring consistency in decision making is an essential part of regulatory best practice. Given this, it is most appropriate to apply the same underlying methodologies used in this inquiry in the course of re-determining the cost reflective level for each tariff in future periods, in the absence of indicators that these methodologies no longer represent a reasonable approach.

9.5.2.2 Review Period

The Federal Government announced a fixed price for carbon for the first three years, 2012/13 to 2014/15. In 2015/16, the carbon price will no longer be fixed, and will be set by the market. Hence the carbon price for the year 2015/16 is uncertain, and accordingly, the Authority recommends that the next inquiry into the efficiency of Synergy's costs and electricity tariffs be conducted in 2014/15 rather than at the end of the four year review period. This will allow for a timely assessment of any movement in Synergy's carbon cost arising from changes in Federal government policy.

While the review period is four years, the Authority recommends an option to conduct a mid-period review of Synergy's costs and tariffs to take into account any significant changes in economic conditions over the review period.

9.5.3 Findings

1. The Authority recommends removal of regulated tariffs for the M1, S1 and T1 tariffs.
2. The Authority recommends that the next inquiry into the efficiency of Synergy's costs and electricity tariffs be conducted in 2014/15 rather than at the end of the four year review period, to allow for a timely assessment of changes in Synergy's carbon cost.
3. The Authority recommends that if there are significant changes to economic conditions, a mid-period review should be undertaken.

APPENDICES

Appendix A. Terms of Reference

INQUIRY INTO THE EFFICIENCY OF SYNERGY'S COSTS AND ELECTRICITY TARIFFS

TERMS OF REFERENCE

I, C. Christian Porter, Treasurer, pursuant to section 32(1) of the *Economic Regulation Authority Act 2003*, request that the Economic Regulation Authority (the Authority) undertake an inquiry into the operating efficiency of the Electricity Retail Corporation (Synergy) and the electricity tariffs regulated under the *Energy Operations (Electricity Retail Corporation) (Charges) By-laws 2006* (By-Laws).

The Authority is to:

1. consider and develop findings on the:
    a. efficiency of Synergy's operating and capital expenditure;
    b. efficiency of Synergy's procurement of wholesale electricity; and
    c. efficiency of Synergy's procurement of Renewable Energy Certificates:
2. determine the efficient cost reflective level for each tariff under the By-Laws over the period 2012/13 to 2015/16, including:
    a. developing recommendations regarding the number of regulated electricity tariffs, and whether any tariffs should be amalgamated; and
    b. taking into account the competitive markets within which Synergy operates and the current operating subsidy arrangements when considering the cost reflective level of each tariff;
3. develop a methodology to regularly re-determine the efficient cost reflective level for each tariff and recommend a period for the review of the efficient cost reflective level of tariffs;
4. consider whether regulated tariffs for contestable large business customers should be phased out, with reference to the competitive nature of this segment of the electricity market; and
5. if regulated, large contestable tariffs are to be phased out, provide recommendations on which tariffs should be phased out and over what timeframe.

GENERAL

The Authority is to:

1. prepare and release an Issues Paper as soon as possible after receiving the reference. The paper is to facilitate public consultation on the basis of invitations for written submission from industry, government and all other stakeholder groups, including the general community;
2. prepare and release a draft report for public consultation; and
3. complete a Final Report on the findings by no later than 31 December 2011.

C. CHRISTIAN PORTER MLA
TREASURER; ATTORNEY GENERAL

Appendix B. Background to the Electricity Sector in Western Australia

The government embarked on a programme to reform the State's electricity industry in 2003. These reforms were intended to create a competitive energy market to encourage private sector investment, increase the stability of electricity supply and ultimately improve service for customers.

Electricity Industry Structure

One of the government's key electricity market reforms was to disaggregate Western Power Corporation, the (then) vertically integrated, state-owned electricity supplier, into four Government Trading Enterprises (**GTEs**). Whilst still government owned, a GTE is managed through an independent Board. Typically, GTEs derive a substantial proportion of their revenue from the sale of their product or services and operate in markets increasingly open to competition from private enterprise.

The *Electricity Corporations Act 2005* established the following GTEs to be operational from 1 April 2006:

- Electricity Generation Corporation (Verve Energy);
- Electricity Networks Corporation (Western Power);
- Electricity Retail Corporation (Synergy); and
- Regional Power Corporation (Horizon Power).

Verve Energy, Western Power and Synergy operate predominantly within the South West Interconnected System (**SWIS**). The SWIS is the largest, interconnected electricity transmission and distribution network in Western Australia and stretches from Kalbarri in the north to Kalgoorlie to the east and Albany to the south. The network supplies electricity to homes and businesses in the more densely populated areas of the State. In contrast, Horizon Power manages and is accountable for electricity supply outside of the SWIS.[89]

Verve Energy

Verve Energy is the state-owned electricity generator and Western Australia's largest energy producer. In 2010/11, Verve Energy generated 60 per cent of the electricity produced in the SWIS.[90] The majority of electricity generated by Verve Energy is purchased by Synergy, the major retailer on the SWIS.

Verve Energy owns and operates four major power stations in Kwinana, Cockburn, Pinjar and Muja. Another power station in Collie is owned by Verve Energy but operated by a private company. Verve Energy also owns a number of smaller power stations located in Mungarra, West Kalgoorlie, Geraldton, and has a joint venture power station at the Worsley alumina refinery near Collie. Verve Energy's power stations in the SWIS have the capacity to produce 2,967 MW of electricity.

[89] The exception is Rottnest Island where the Rottnest Island Authority manages the entire electricity supply process. Background information on Horizon Power can be found in the Authority's Inquiry into the Funding Arrangements of Horizon Power final report.

[90] Verve Energy (2011), Annual Report p13.

Verve Energy's portfolio also includes renewable energy sources throughout Western Australia with wind farms in Albany, Esperance, Bremer Bay, Hopetoun, Denham, Kalbarri and Coral Bay. It also operates a solar facility in Kalbarri and a pilot biomass plant in Narrogin.[91]

Verve Energy participates in the Wholesale Electricity Market (**WEM**) and competes with privately owned electricity generators in the SWIS to sell electricity to retailers. The majority (90 per cent) of Verve Energy's electricity is contracted to Synergy, the state-owned electricity retailer.[92] Outside the SWIS, Verve Energy sells electricity from wind and wind-diesel systems to Horizon Power.

Western Power

Western Power is responsible for the transmission and distribution of electricity in the south west of Western Australia, including Perth. Consisting of nearly 96,000 km of powerlines within the SWIS, Western Power's electricity network is one of the largest isolated networks in the world. Western Power transports electricity from power stations to towns and cities and then distributes it to over 900,000 residential connections, around 86,000 small to medium business connections, 19,000 major commercial customers, 46 generators (such as Verve Energy) and the 230,000 streetlights that are connected to the network.[93]

Western Power is responsible for operating and maintaining this network and restoring power after interruptions. It is also tasked with developing and extending the network to meet the needs of customers and developers.

Within the SWIS, companies who produce electricity (generators) and companies who sell electricity (retailers) all have access to Western Power's network. Electricity retailers buy power from electricity generators and pay Western Power a fee for transporting that electricity across the network to their customers. The level of these network costs is set by the Authority through an access arrangement[94] to cover Western Power's efficient cost of operation that also includes a suitable return on investment. To date, reviews of access arrangement have been undertaken by the Authority every three years.

Western Power's distribution network charge includes the Tariff Equalisation Contribution (**TEC**) to fund the Tariff Equalisation Fund (**TEF**). This fund was set up in support of the uniform tariff policy so that small use customers in regional Western Australia pay the same electricity tariffs as SWIS customers. The additional costs incurred by Horizon Power in supplying electricity to regional Western Australia are funded from the TEF. The TEC payments collected through network distribution tariffs are collated within the Tariff Equalisation Fund (**TEF**). The annual amount of the TEC is determined by government and published in the government Gazette.

---

91 Verve Energy (2011), website www.verveenergy.com.au.

92 Verve Energy (2011), Annual Report p13.

93 Western Power (2011), Annual Report pp13-14.

94 ERA website, www.erawa.com.au

Synergy

Synergy is responsible for purchasing and retailing electricity to approximately one million industrial, commercial and residential customers in the SWIS. It is the largest electricity retailer and sells around 70 per cent of the electricity sold in the SWIS, receiving approximately $2.7 billion in revenue each year.[95] From the tariff revenue it collects, Synergy covers the costs of its retail activities, as well as a retail margin (return on investment).

A significant element of Synergy's operating costs is the wholesale procurement cost of electricity. Although a proportion of Synergy's wholesale electricity requirement is sourced, at competitive rates from the wholesale market, the majority of Synergy's electricity requirement is provided by Verve Energy under the vesting contract. Synergy also has to purchase a given percentage of electricity from renewable resources, in line with the Federal Government's Renewable Energy Target that requires 20 per cent of Australia's energy to come from renewable sources by 2020.[96]

Another element of the costs incurred by retailers are the network charges payable to Western Power for access to the SWIS transmission and distribution network that delivers electricity to retail customers.

Synergy also receives Community Service Obligation payments from the State Government, to cover the costs of specific customer service programs, and also to cover the shortfall between electricity revenues and supply costs. Although electricity prices on the SWIS have been moving towards cost reflective levels, tariffs are still below the cost of supplying electricity, so the State Government introduced a 'tariff adjustment payment' (via a CSO payment) to Synergy in 2009/10.

Horizon Power

Horizon Power is responsible for generating (or procuring), transmitting, distributing and retailing electricity to residential, industrial and commercial customers in regional Western Australia (outside the SWIS). This is achieved through 34 islanded or isolated electricity systems that power towns and two interconnected systems: one in the Pilbara (the North West Interconnected System) and a smaller regional system that connects the towns of Kununurra and Wyndham.[97]

Horizon Power operates from a head office in Karratha in the Pilbara region and has additional offices in Kununurra, Broome, Carnarvon, Esperance and Perth.

Horizon Power generates around 13 per cent of the electricity utilised over its supply area and purchases the remaining energy (87 per cent) from privately owned generators including a small percentage of renewable energy from Verve Energy. Throughout its supply area, energy is generated from various sources including natural gas, diesel and renewable energy such as hydro, wind farms and solar. Horizon Power then distributes and retails electricity to 43,000 customer connections.

[95] Synergy (2011), Annual Report, p9.

[96] This requirement also applies to the other electricity retailers in Western Australia.

[97] Horizon Power (2011), Annual Report p4.

Horizon Power's customers range from those in remote, isolated communities with less than 100 people, to residents and small businesses in regional towns to major mining companies in the Pilbara and Mid West.[98]

The Wholesale Electricity Market

In 2006, another key government reform was to establish a Wholesale Electricity Market (**WEM**) to operate within the SWIS.

History

The WEM was created with the objectives of:

- promoting the economically efficient, safe and reliable production and supply of electricity;
- encouraging competition amongst generators and retailers;
- facilitating the efficient entry of new competitors (generators and retailers);
- avoiding discrimination against particular types of energy technologies (e.g. renewables);
- minimising the long term cost of supplying electricity; and
- encouraging the management of the quantity and timing of energy consumption.[99]

At the commencement of the WEM, a number of measures were put in place to facilitate the introduction of competition into the SWIS and to mitigate the market power of the incumbent generator and retailer, Verve Energy and Synergy respectively. These measures included:

- The Vesting Contract (2006) with a Displacement Mechanism[100] which had the objective of gradually reducing the level of wholesale electricity supplied from Verve Energy to Synergy;
- Verve Energy's generation capacity was capped at 3000 MW;
- Verve Energy was restricted to operating as an electricity wholesaler and was unable to become an electricity retailer until at least 2013 (extendable to 2016 – the 'Restriction'); and
- Synergy was unable to generate electricity until 2013 (extendable until 2016 – the 'Prohibition').

[98] ERA (2011), Final report into the Funding Arrangements of Horizon Power.

[99] IMO (2006), The South West Interconnected System Wholesale Electricity Market: An Overview, pp. 6-7

[100] Under the Displacement Mechanism, Synergy's electricity load volumes were gradually exposed to competitive sourcing, with Verve Energy and independent power producers able to tender for these volumes.

The original Vesting Contact (2006) was a bilateral contract for the wholesale supply of energy and electricity capacity from Verve Energy to Synergy. The amount of energy and electricity capacity[101] traded under the original Vesting Contract (2006) reduced over time with the operation of the Displacement Mechanism and as contestable[102] customers moved to alternative retailers and Synergy's inherited retail contracts expired. Synergy also had the option to commercially negotiate wholesale electricity supply arrangements outside of the original Vesting Contract (2006) with any generator, including Verve Energy.

From 2007/08 to 2010/11, Verve Energy's share of total supply capacity[103] in the WEM fell from around 77 per cent to 60 per cent while Synergy has sourced an increasing quantity of electricity from private generators.

The Displacement Mechanism also played a role in providing information to the market[104] and facilitated the entry of new private generators. The value of private investment in electricity generation since 2006 is around $2.6 billion.[105]

Management of the WEM

The operation of the different elements of the WEM is managed by the Independent Market Operator (IMO), operated by System Management (a branch of Western Power), and monitored by the Authority.

The IMO administers and operates the WEM.[106] The Market Rules list the IMO's services as:[107]

- market operation services, including the operation of the reserve capacity market, short term electricity market and Balancing and the IMO's settlement and information release functions;
- system planning services, including the IMO's performance of the long term projected assessment of system adequacy (**PASA**) function; and
- market administration services, including the IMO's performance of the Market Rule change process, market procedure change process, the operation of the Market Advisory Committee and other consultation, monitoring, enforcement, audit, registration related functions and other functions under the Market Rules.

System Management is a segregated business unit of Western Power, with the function of operating the SWIS in a secure and reliable manner.[108] Further functions of System Management are to:[109]

---

[101] The supply of energy describes the average power output of electricity over a period of time and is measured in mega-watt hours (MWh). The capacity of a generator describes the maximum instantaneous electricity output that the generator can produce and is measured in mega-watts (MW).

[102] Contestable customers consume more than 50 MWh per annum and can choose their electricity retailer.

[103] Supply capacity includes both generation and demand side management.

[104] The Displacement Mechanism included requirements to publish information about demand, vesting prices, volumes and Synergy's displacement requirements.

[105] Includes private investment by Griffin Energy (Bluewaters 1 and 2), ERM Power (NewGen Kwinana and Neerabup), Perth Energy (Kwinana Swift), UBS International Infrastructure Fund and the Retail Employees Superannuation Trust (Collgar wind farm, Tesla Corporation (diesel units) and Merredin Energy (Merredin Power Station.

[106] The IMO's functions are listed in Clause 2.1.2 of the Market Rules.

[107] Market Rules, Clause 2.22.1

- procure adequate ancillary services when Verve Energy cannot meet these requirements;
- assist the IMO in the processing of applications for the participation and registration, deregistration and transfer of facilities;
- develop, amend and replace market procedures, where required by the Market Rules;
- release information required to be released by the Market Rules;
- monitor compliance with the Market Rules in relation to dispatch and power system security and reliability; and
- carry out any other functions or obligations conferred on it in the Market Rules.

The Economic Regulation Authority has a range of wholesale electricity market surveillance functions under the Market Rules. The Authority:

- monitors market operations and conducts reviews to ensure that the market is effectively meeting the Wholesale Market Objectives set out in the Market Rules;
- investigates behaviour that does not meet the Wholesale Market Objectives;
- provides reports to the Minister, at least annually, on:
  - summary of market data;
  - the effectiveness of the market, the IMO and System Management;
  - behaviour that does not meet the Wholesale Market Objectives; and
  - recommendations to improve the effectiveness of the market; and
- approves the allowable revenue of the IMO and System Management, the Maximum Reserve Capacity Price, and Energy Price Limits.

The allowable revenues for the IMO and System Management are determined periodically by the Economic Regulation Authority.[110] In March 2010, the Authority determined the allowable revenues of the IMO and System Management entities for the period 2010/11 to 2012/13.[111]

- Following the Authority's revenue determination, the IMO's budget may be adjusted to comply with the Market Rules requirement that the IMO return an operating surplus to market participants, through an adjustment to the allowable revenue two years hence.

---

108 Clause 2.2.1 of the Market Rules.

109 Clause 2.2.2 of the Market Rules.

110 Clause 2.22 of the Market Rules requires the Authority to determine the revenue required by the IMO to provide the services the IMO is required to provide, in terms of market operation, market administration and system planning. Clause 2.23 of the Market Rules requires the Authority to determine the revenue required by System Management to provide system operation services, including all of System Management's functions and obligations under the Market Rules.

111 Economic Regulation Authority (31 March 2010), *Allowable Revenue Determination – Independent Market Operator*; and Economic Regulation Authority (31 March 2010), *Allowable Revenue Determination – System Management*. Both of these determinations are available on the Authority website.

- The IMO's budget may also be adjusted for additional expenditure approved by government. For example, in December 2010, the Treasurer approved additional loan funding to the IMO of $7.98 million across 2010/11 and 2011/12 to fund the implementation of the Market Evolution Program.[112] This program is to consult with WEM participants to develop and implement changes to the market rules, procedures and IT systems to improve the operation of the market.

Structure and Operation of the WEM

The WEM has two components:

- a ***capacity market***, to provide incentives for long-term investment in generation capacity; and
- an ***energy market***, to allow for the buying and selling of electricity. The energy market includes bilateral contracts, the Short Term Energy Market (**STEM**) and the Balancing Market.

Capacity Market

The capacity market operates under the Reserve Capacity Mechanism (**RCM**) and is intended to work together with bilateral contracts, the STEM and the Balancing Market to promote investment in the optimal quantity of generation capacity to meet demand in the SWIS.

Generating plant investment decisions are based on a host of factors including projected price and quantity values resulting from the RCM, such as the Maximum Reserve Capacity Price (**MRCP**),[113] energy and fuel prices, carbon pricing, other business variables and factors outside the WEM. The RCM was designed to promote investment in sufficient capacity to meet demand in the SWIS and operates on a two-year-ahead cycle.

- Each year, the IMO prepares an assessment of the amount of capacity that is required to meet the forecast demand in a future Capacity Year. The RCM provides a guarantee of payment to investors providing certified capacity (Capacity Credits). The capacity payment is based on the MRCP, which is proposed annually by the IMO and approved by the Authority. For the 2013/14 Capacity Year, the MRCP is $240,600 per MW.[114]
- In return for receiving capacity payments, generators (and Demand Side Management (**DSM**) providers[115]) are required to offer their capacity into the market at all times (unless otherwise approved, e.g. undergoing scheduled maintenance).

[112] *IMO Operational Strategy 2011/12*, pp11-13.

[113] If there is a shortage of capacity offered into the market for a given Capacity Year, the IMO can run an auction to procure additional capacity, which would then be paid at the MRCP. An auction has not occurred to date. When there is surplus capacity, the actual capacity payment (per MW) is adjusted to 85 per cent of the MRCP. This capacity price is known as the Reserve Capacity Price.

[114] ERA (2011), Decision on the Maximum Reserve Capacity Price proposed by the Independent Market Operator for the 2013/14 Reserve Capacity Year.

[115] Demand Side Management providers are generators or large electricity users who agree to curtail their electricity load by a defined amount upon request and in return for payment.

The overall capacity required for each year, the Reserve Capacity Requirement, is set by the IMO so as to be sufficient to meet the forecast annual peak demand even if the largest single generator was to be unavailable. The IMO assigns Capacity Credits to generators and DSM providers[116] (e.g. Water Corporation, Energy Response) over and above the level of the Reserve Capacity Requirement to meet the energy demands of the SWIS and create a capacity 'cushion'.[117] Generators and DSM providers can trade their Capacity Credits with retailers and in doing so receive a source of revenue. The trade in Capacity Credits occurs regardless of whether the electricity represented by the credits is actually sold. This has the effect of having generation capacity available to provide energy (even when it is only required on a few occasions) and provides a revenue incentive for investment in generators that may only operate for a few hours each year.

In the capacity market, the IMO assigns retailers (such as Synergy) an Individual Reserve Capacity Requirement (**IRCR**)[118] obligation, based on their loads associated with peak usage. These IRCRs are set annually and adjusted each month. This is matched by the total Capacity Credits assigned annually to generators and Demand Side Management (**DSM**) providers. Currently, there is no limit on the amount of capacity that the IMO can certify for each capacity year. With the exception of the 2010/11 Capacity Year, procured capacity in the SWIS has exceeded the Reserve Capacity Requirement each year by more than five per cent.

The IRCR is set just before the start of the current Capacity Year, while the MRCP is set two years in advance. Retailers are exposed to the current MRCP if they require additional Credits to meet their IRCR. Hedging of this risk is limited if generators/DSM aggregators do not want to enter into forward bilateral contracts which match the retailer's expectation of its future IRCR. This may occur when Capacity providers expect the MRCP to increase in future years. A long term trend is that, with the exceptions of the 2011/12 and 2013/14 Capacity Years, the MRCP has increased significantly each year. There has been a significant increase in the percentage of Capacity Credits being traded through the IMO since October 2010.[119]

Energy Market

The majority of electricity traded in the WEM is through bilateral supply contracts negotiated between generators and retailers. These contracts can have terms of a few hours or several years.

[116] Capacity payments per MWh are equivalent for the certified capacity of generators and DSM providers.

[117] Independent Market Operator (2009), Reserve Capacity Mechanism Progress Report, p4.

[118] To fund capacity that is procured through the Reserve Capacity Mechanism, Market Customers are given an IRCR obligation. The IRCR is a quantity of capacity (expressed in MW) which represents that customer's contribution to the total system load during peak times.

[119] October 2010 was the beginning of the 2010/11 Capacity Year. Reference: Lantau Group, 'RCM Review Issues', Presentation to the Rules Development Implementation Working Group, Meeting 13, 31 May 2011

The Short Term Electricity Market (**STEM**) complements wholesale bilateral contracts by providing a forward energy market to allow generators to sell any excess capacity and for retailers to purchase additional energy at specified times. The STEM is operated a day ahead. Generators inform the IMO as to how much energy they will be supplying and how much the retailers will consume for each half hour of the following day, with an auction determining half hourly prices for the subsequent 'electricity day'. To maintain system security, System Management[120] then matches physical supply and demand in the system through real-time balancing.[121] Arrangements for intermittent generators, such as wind farms, are slightly different, as their output is less predictable.

While participants can choose their relative positions with bilateral contracts and STEM trades, by default they will be exposed to the Balancing Market, with their net position adjusted so that supply equals real-time demand. The IMO undertakes the financial settlement function and transfers payments between market participants. Thus, the STEM allows participants to make short-term adjustments around their bilateral positions. The STEM also allows those who do not have bilateral contract arrangements to participate in the electricity market.

Overall, the Authority has reported that the WEM has generally operated effectively since commencement and that a number of new entrants are established in the market bringing increased capacity and greater diversity in the sources of electricity generation. The share of capacity provided by independent power producers will have increased from 11 per cent in 2005/06 to 44 per cent in 2012/13.[122] An increased level of competition has also been observed through increased volumes being traded in the STEM and increased bilateral contracting occurring between parties other than Synergy and Verve Energy. Traded quantities in the STEM have increased since the start of the wholesale market and currently represent around 5 per cent of total traded quantities (bilateral plus STEM trades).

Ancillary Services

Ancillary services are primarily provided by Verve Energy and are required to maintain the security and reliability of the SWIS, facilitate orderly trading in electricity and to ensure that electricity supplies are of acceptable quality. The following types of ancillary services are defined in the Market Rules: [123]

- **Load Following**. Load following is the primary mechanism in real-time to ensure that supply and demand are balanced and system frequency is maintained.[124] Load following accounts for the difference between the scheduled energy and actual load and intermittent generation.
- **Spinning Reserve**. This service holds capacity in reserve to respond quickly should another unit experience a forced outage. The capacity includes on-line generation capacity, dispatchable loads and interruptible loads (i.e. loads that respond automatically to frequency drops).

[120] System Management is a segregated business unit within Western Power established under the WEM Rules. It has a central role in scheduling of generator and transmission outages and managing the real-time operation of the power system.

[121] "Balancing" refers to the process for meeting market participants' actual (real-time) supply and consumption energy levels from contracted bilateral and STEM positions. Currently, Verve Energy is the default supplier of balancing support services.

[122] ERA (2011), 2010 Wholesale Electricity Market Report for the Minister for Energy, p53.

[123] IMO website (http:/www.imowa.com.au/ancillary-services-types)

[124] The operating standard for the normal operating conditions on the SWIS is that system frequency must be maintained between 49.80 Hz and 50.20 Hz for 99 per cent of the time.

- **Load Rejection Reserve**. This service requires that generators be maintained in a state in which they can rapidly increase their output should a system fault result in the loss of load. This service is particularly important overnight when most generating units in the system are operating at minimum loading and have no capability to decrease their output in the time frame required.
- **Dispatch Support**. This service ensures voltage levels around the power system are maintained and includes other services required to support the security and reliability of the power system that are not covered by other ancillary services.
- **System Restart**. This service allows part of the power system to be re-energised by black start equipped generation capacity (generators that can be started up without requiring a supply of energy from the transmission network) following a system wide black out.

Renewable Energy Generation

Federal and State Government policies are driving the increases in the proportion of electricity generated from renewable sources. This is in order to reduce carbon emissions in accordance with commitments under the Kyoto Protocol.[125] Electricity generated from burning fossil fuels such as coal, oil and gas releases gases such as carbon dioxide, which contribute to global warming. In contrast, electricity generated from sources such as wind, solar, geothermal, wave and tidal typically have zero carbon emissions. Therefore, increasing renewable energy as a proportion of all energy produced is intended to reduce overall carbon emissions.

In 2003/04, the consumption of renewable energy in the SWIS was one per cent of the total energy generated. By 2006/07, the renewable percentage was 5.4 per cent of total electricity generated, and in 2008/09, around five per cent.[126]

There are two key Federal Government climate change policy instruments:

- the Clean Energy Plan, which introduces carbon pricing from 1 July 2012 for three years before transitioning to a full emissions trading scheme;[127] and
- a Renewable Energy Target (**RET**). In 2009, the Federal Government committed to an increased RET of generating 20 per cent of Australia's electricity supply from renewable energy sources by 2020.[128] In January 2011, the RET split into two parts: the Large-scale Renewable Energy Target (**LRET**) and the Small-scale Renewable Energy Scheme (**SRES**).

Under the LRET/SRES framework liable entities (usually electricity retailers, such as Synergy) are required to:

- procure and surrender annually, Large-scale Generation Certificates (**LGCs**) to meet the Renewable Power Percentage (**RPP**). For 2011, the RPP was set at 5.62 per cent of the total estimated electricity consumption in the calendar year, which is equivalent to 10.6 million LGCs; and

[125] For more information see www.unfccc.int Kyoto

[126] Office of Energy (2010), Renewable Energy Handbook Western Australia 2010, p12.

[127] Multi-party Climate Change Committee (www.pm.gov.au carbon). The $23 tonne/CO2 equivalent was announced 10 July 2011 in the Federal Government's Clean Energy Package.

[128] This is equivalent to 45,000 GWh: www.climatechange.gov.au.

- procure and surrender quarterly, Small-scale Technology Certificates (**STCs**) to meet the Small-scale Technology Percentage (**STP**). The STP was set at 14.8 per cent of the total estimated electricity consumption for 2011, equivalent to 27 million STCs.

Renewable energy generators (who may also be retailers) create certificates, and liable entities (typically retailers) procure certificates in various ways, including:

- on-line, using the Renewable Energy Certificate (**REC**) Registry which is provided by the federal Office of the Renewable Energy Regulator (**ORER**); and
- via bilateral contracts.

Each LGC or STC certificate is equivalent to 1 MWh of renewable energy generated or 1 MWh of fossil fuel energy foregone. The price of certificates varies according to the supply of, and demand for, certificates at any particular time.[129] If liable entities do not purchase and surrender sufficient certificates to meet their liabilities then they incur a penalty of $65 per MWh.

Retailers typically obtain a significant amount of renewable certificates through long-term bilateral contracts. In comparison, the actual liability is only known closer to the liability year. Under the regulations, the RPP and the STP must be published by 31 March of the year in which it applies. If this does not occur there is a default formula to calculate these percentages.

On its website, the ORER comments that:

> "The trade in these certificates thereby provides a financial incentive for investment in renewable energy power stations, and for the installation of solar water heaters, heat pumps, and small-scale solar panel, wind and hydro systems."[130]

In March 2011, the ORER reported that nearly 100 per cent of electricity retailers in Australia complied with the renewable energy target scheme in 2009. Compliance was measured at 99.96 per cent with just 76 liable parties being assessed as failing to surrender sufficient renewable certificates to meet their liability.[131]

Outline of Synergy's Operations

Synergy is responsible for purchasing and retailing electricity to approximately one million industrial, commercial and residential customers in the SWIS. It is the largest electricity retailer in the SWIS and Synergy's key activities include energy trading (purchasing), marketing, sales, customer service, billing and payment processing.

Synergy has a number of principal functions under the *Electricity Corporations Act 2005*, with the key ones being to:

> "(a) to supply electricity to consumers and services which improve the efficiency of electricity supply and the management of demand;

[129] Alternatively, STCs can be purchased through the STC clearing house, also managed by ORER, for a fixed price of $40 per certificate.

[130] ORER website www.orer.gov.au/publications/lret-sres-basics.html.

[131] ORER (2011), Media release 'Strong compliance by liable entities'.

(b) to purchase or otherwise acquire electricity for the purposes of paragraph (a);"[132]

In undertaking its functions, Synergy must act in accordance with prudent commercial principles and attempt to make a profit.[133]

The sections below give an overview of Synergy's current standards of service, income, and costs.

Service Standards

Synergy's service standards predominantly relate to the retail services it provides to its customers and Synergy regularly publishes information relating to its performance in its Annual Report and Quarterly Reports.[134]

However, Synergy's main reporting requirement is undertaken as part of its electricity retail licence obligations.[135] Synergy reports against performance standards covering billing, payment arrangements, answering customer queries and complaints and compensating customers for breaches of particular service standards.[136] Each year the Authority publishes its report on the performance of electricity retailers, the latest version of which is the 2010/11 report.[137]

Sources of Income

Synergy currently receives income from a variety of sources including:

- regulated tariff revenue;
- Community Service Obligation payments (**CSOs**);
- revenue from large, commercial electricity contracts;
- other energy revenue, e.g. from gas sales; and
- other income, e.g. interest received.

Each of these elements is discussed in more detail in the following sections. Synergy's actual revenue from 2006 to 2011 and budgeted revenue for 2011/12 is shown in Figure 8 below.

[132] Electricity Corporations Act 2005. Section 44 (a) and (b).

[133] Electricity Corporations Act 2005, Section 61 (1) (a) and (b).

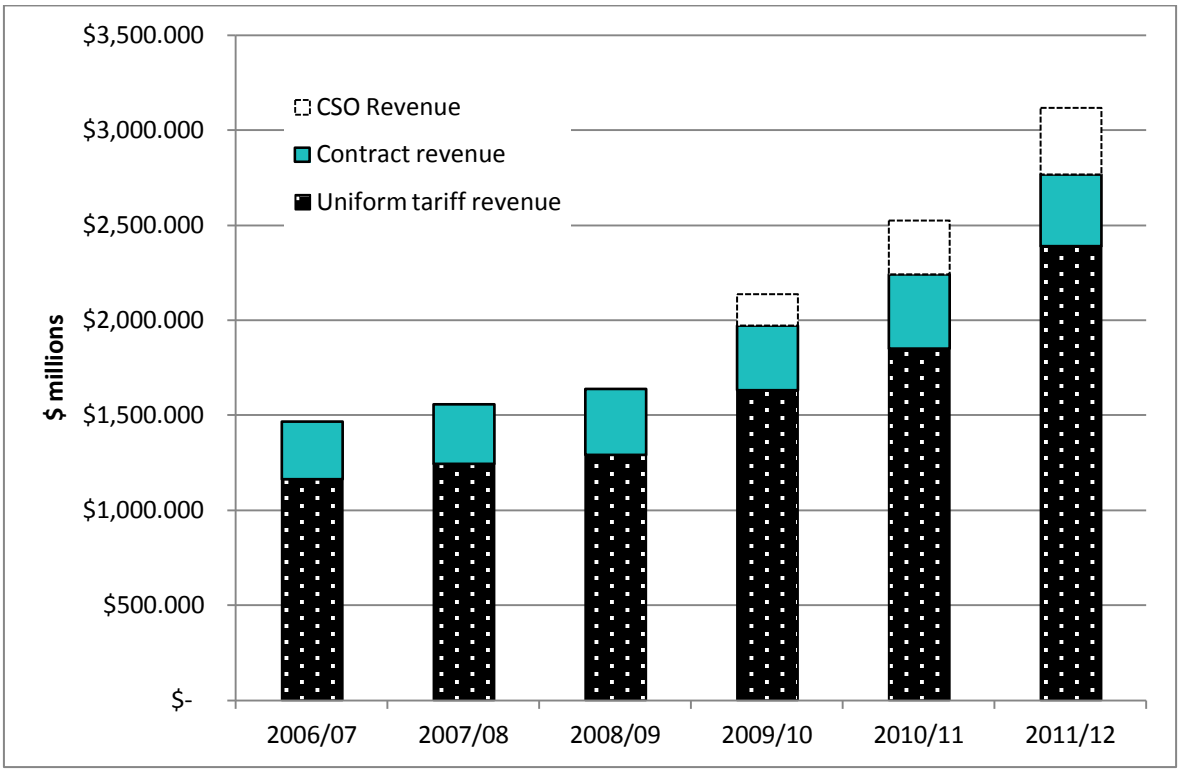
[134] For example, Synergy Annual Report 2009/10, p17

[135] As with all electricity retail licences, Synergy's licence includes a condition that it must provide to the Authority any information the Authority requires to fulfil its functions under the *Electricity Industry Act 2004*. The Authority has specified the performance information it requires for Synergy and other electricity retailers in the Electricity Compliance Reporting Manual.

[136] The Code of Conduct includes service standard payments for facilitating customer reconnections (after disconnection), wrongful disconnection and customer complaint handling.

[137] ERA (2012), www.erawa.com.au 2010/11 Annual Performance Report - Electricity Retailers

Figure 8 Synergy's Actual and Budgeted Income (Electricity Only) ($m, nominal) 2006/07 to 2011/12



Source: Synergy

Within the Western Australian electricity market customers are grouped by their electricity consumption as follows:

- Customers who consume less than 50 MWh of electricity per annum.
    - These are franchise customers and are charged regulated tariff rates. They are also referred to as non-contestable customers as they cannot choose their electricity retailer and must be supplied by Synergy. Typically these are residential and small business customers.
- Customers who consume between 50 and 160 MWh of electricity per annum. This quantity of electricity consumption equates to an annual electricity charge of between $12,000 and $40,000.[138]
    - These customers are also franchise customers as they are eligible for regulated tariffs. However, this group of customers are also called contestable customers as they are able to choose their retailer and in doing move out of regulated tariffs.
    - Despite having a choice of retailer, the majority of contestable customers choose to remain on regulated tariffs through Synergy. The main reasons for this are that Synergy is the incumbent supplier and, without clear incentives, customers are unlikely to change supplier. The lack of cost reflective tariffs in the SWIS also means that it can be more advantageous for customers to remain on subsidised regulated tariffs. As such, Synergy retails to 100 per cent of all contestable residential customers in the SWIS and 86 per cent of contestable business customers.

[138] Synergy (2011), email from Synergy to ERA dated 8 April 2011.

- Customers who consume more than 160 MWh of electricity per annum. This is equivalent to an annual charge of above $40,000.
    - These customers are not franchise customers as they are not eligible for regulated tariffs.
    - Instead these contestable customers bilaterally negotiate their electricity supply and enter into a customised retail contract with Synergy or any other retailer.

The revenue received from these different customer groups is discussed below.

Regulated Tariffs

The regulated tariffs that Synergy charges its customers are listed in the *Energy Operators (Electricity Retail Corporation) (Charges) By-Laws 2006 – Schedule 1*. The amounts for each tariff are set by the Minister for Energy and published in the *Government Gazette*. A full list of the current tariffs and descriptions is shown in Appendix C.

With the exception of the streetlight tariff (W1), regulated tariffs are comprised of a fixed daily charge (regardless of whether electricity is used or not) and a volumetric charge per unit of electricity consumed.

The 13 tariffs can be subdivided into those for residential and commercial customers and also subdivided into those with flat volumetric rates or variable volumetric rates. Flat volumetric rates remain the same regardless of when electricity is consumed. Variable volumetric rates differ depending upon the time of day that electricity is used or the customer's demand for electricity. These groupings are shown in Table 36 below.

Table 36 Regulated Tariff Groupings

Tariff category	Volumetric charge Flat rate	Volumetric charge Varies with time of day or demand
Residential tariffs	A1	B1
Commercial tariffs		
- **Low/medium voltage**	L1, L3	R1, R3, S1
- **High voltage**	M1	T1
Other	C1, D1, K1, W1, Z1	

Source: ERA Analysis

Synergy's tariff categories

A1 is the standard residential tariff charged to most households (this assumes the amount of electricity supplied to the premise is less than 50 MWh per annum).

B1 is only available for residential water heating during a six hour period from 11 pm to 6 am.

L1 and L3 are general business tariffs. L1 is applied if the business consumes less than 50 MWh per annum and L3 is applied if consumption is greater than 50 MWh per annum.

M1 is also a business tariff but for those businesses that require electricity supplied at a higher voltage (6.6 kV to 33 kV).

R1 and R3 are time-of-use tariffs for businesses, comprising a higher volumetric charge for electricity consumed on peak compared to a lower off peak charge. This is beneficial for businesses who consume more than 20-30 per cent of electricity during off peak periods. R1 is applied if the business consumes less than 50 MWh per annum and R3 is applied if consumption is greater than 50 MWh per annum.

S1 is a demand related tariff for larger business customers who utilise electricity more efficiently as measured by a power factor greater than 0.8.

T1 is similar to S1 but is applied to those businesses that require electricity supplied at a higher voltage (6.6 kV to 33 kV).

C1 and D1 are only available for charitable or benevolent organisations.

K1 is used where the premise is dual purpose, for example a residence above a retail premise or a home business, where the wiring is not separate and so residential and commercial electricity use cannot be independently metered.

W1/Z1 is for the electricity consumed by traffic lights/streetlights respectively. This is charged to the relevant Local Council or Main Roads Western Australia depending upon where the traffic lights/streetlights are situated.

The introduction of 'time-of-use' and 'demand related' tariffs helps to send appropriate price signals to customers regarding the cost of supplying electricity at peak times compared to off peak times. This enables customers to moderate their peak electricity use, for example by residential customers running washing machines or dishwashers in off peak periods.

Synergy operates a 'SmartPower' tariff SM1[139] for residential customers where differential volumetric tariffs are charged at certain times over a 24 hour period. To be eligible for these rates a compatible meter must be installed at the customer's premises which is capable of recording electricity consumption over given periods. This meter is installed at the customer's expense.[140]

[139] The SmartPower tariff has been introduced by Synergy and is not a regulated tariff under the By-Laws.

[140] Synergy (2011), www.synergy.net.au 'Standard Electricity Prices and Charges SWIS Effective 1 July 2010 (in some cases, customers can have their existing meter reprogrammed)

The regulated tariffs listed above generate the majority of Synergy's income. However, as regulated tariffs are not yet at cost reflective levels there is a shortfall between the income received and the cost of supplying electricity. This shortfall has been funded by a CSO payment since 2009/10.

Under the current tariff policy, regulated tariffs are also available for business customers. These tariffs apply to both non-contestable business customers using less than 50 MWh per year (L1) and also to contestable business customers using 50 to 160 MWh per year (or annual electricity bills of $12,000 to $40,000) (L3). A typical customer in this range would be a medium-sized manufacturing or engineering company.

As a contestable customer can choose their electricity retailer, the retail market for contestable customers is considered competitive. However, Synergy retails to over 80 per cent of contestable business customers and charges regulated tariff rates. Western Australia is the only state that regulates tariffs for large contestable business customers.

The Office of Energy's 2009 Electricity Retail Market Review recommended that tariffs for contestable customers move to cost reflective levels in the SWIS from 2009/10. The reasons for this were given as:

- large electricity customers are generally in a superior position (compared to small use customers) in terms of the incentive, expertise and capacity to manage their electricity consumption and negotiate preferential terms with alternative electricity retailers;
- removal of the unnecessary costs to government and industry in setting and commenting on price determinations for these regulated tariffs; and
- retailers will have an added incentive to compete for customers that consume significant quantities of electricity.[141]

However, tariffs for medium to large contestable business customers continue to remain on a 'glide path' to cost reflective levels. These are the cost reflective levels calculated by the OoE in 2009 and published in its report.[142] The latest assumed glide path for selected contestable tariffs is shown in Table 37 below.

Table 37 Contestable Tariff Glide Path (Annual Percentage Increases) to the Cost Reflective Tariff Levels Calculated by the OoE in 2009 2011/12 to 2014/15

Tariff	2011/12	2012/13	2013/14	2014/15
Medium business (L3)	29.8%	6.7%	1.9%	6.8%
Medium business (R3)	19.7%	2.9%	1.2%	5.6%
Large business (M1)	19.6%	3.2%	4.7%	6.2%
Large business – low voltage (S1)	12.5%	3.9%	1.0%	5.6%
Large business – high voltage (T1)	13.9%	5.1%	0.7%	5.5%

Source: Department of Treasury and Finance 2011/12 Budget Paper No. 3, Appendix 8, p286

As part of this inquiry and in line with the Terms of Reference, the Authority will consider whether regulated tariffs for large contestable customers should be phased out and, if so, over what timeframe.

[141] OOE (2009), Electricity Retail Market Review, p34

[142] Ibid.

Renewable Energy Tariffs

There are additional tariff-related incentives to encourage households, non-profit organisations and educational institutions to install renewable energy systems. Synergy offers the Renewable Energy Buyback Scheme (**REBS**) and a Feed-in Tariff (now closed) to certain groups of customers. To be eligible for both schemes customers are required to have a bi-directional meter fitted[143] at their own expense, which is capable of measuring electricity flowing into and out of the property.

*Renewable Energy Buyback Scheme (**REBS**)*

REBS is available to residential customers, non-profit organisations and educational establishments who have installed renewable energy systems. The scheme enables Synergy to buy net renewable energy from customers. Under the REBS scheme customers are billed for the net amount of energy imported from the SWIS and credited for the amount of net renewable energy exported to the SWIS. The price at which Synergy buys net renewable energy for various tariff classes is shown on its website.[144] REBS is managed by Synergy and the buy back rate offered reflects the wholesale value of electricity to Synergy. The buy back rate is reviewed annually.

Feed-in Tariffs

The Feed-in Tariff scheme was introduced by the State Government on 1 August 2010 at an initial rate of 40 cents per kWh on net exports to the SWIS or regional electricity networks from qualifying residential renewable energy installations, and is administered by Synergy and Horizon Power. The tariff was reduced to 20c/kWh on 1st July 2011 and then suspended on 1st August 2011, as it was estimated that the scheme had already reached its cap of 150 MW installed capacity. The rate was offered for 10 years and acted as an additional financial incentive to encourage residential customers to install small-scale renewable energy systems. Customers who qualified for either the 40 cent or 20 cent feed in tariff prior to suspension will continue to receive the tariff for the duration of their ten year period.

When the tariff was reduced on 1 July 2011 from 40 c/kWh to 20 c/kWh, the Office of Energy commented on its website on the lower tariff level:

> '..the benefit householders receive is more in line with the cost of their renewable energy systems'.[145]

The 20 cent per kWh rate was also commensurate with the discounted weighted average tariff (**DWAT**) for the SWIS calculated by the Authority as part of its recent inquiry into the funding arrangements of Horizon Power. The Authority calculated a DWAT of 19 cents per kWh (real as at 30 June 2009) or 20 cents per kWh (nominal). The DWAT for the SWIS was calculated as an average cost reflective tariff against which to compare cost reflective tariffs across Horizon Power's supply area.

Feed in tariff payments, and the costs of administering the scheme, are reimbursed to Synergy and Horizon Power by the State Government.

---

[143] Some customers may just require their existing meter to be reprogrammed.

[144] Synergy website, www.synergy.net.au/docs/rebs_pricing_schedule.pdf.

[145] Office of Energy (2011), as at May 2011, www.energy.wa.gov.au feed-in tariff.

*Community Service Obligation (**CSO**) Payments*

CSO payments are funds from government to provide for specific rebate schemes or funding shortfalls. A summary of Synergy's CSOs from 2010/11 to 2014/15 is shown in Table 38 below.

Table 38 Subsidies Received by Synergy ($m nominal) 2010/11 to 2014/15

Subsidies	2010/11 Estimated actual	2011/12 Estimated budget	2012/13 Forward estimate	2013/14 Forward estimate	2014/15 Forward estimate
Tariff adjustment payment	282.9	349.6	346.5	194.6	101.9
Feed-in Tariff	13.0	24.0	29.8	30.3	30.3
Energy rebate	36.4	40.0	43.1	49.5	56.8
Dependent child rebate	11.6	12.6	13.6	15.7	18.1
Hardship package	4.3	11.4	13.6	11.2	13.8
Charitable organisation rebate	1.2	1.5	1.6	1.7	1.8
Air conditioning allowance	0.1	0.1	0.1	0.1	0.1
Total	**349.6**	**439.2**	**448.2**	**303.1**	**222.8**

Source: Department of Treasury and Finance, 2011/12 State Budget Paper No. 3 – Fiscal and Economic Outlook, Appendix 8, p293

Totals may not add due to rounding.

The total annual subsidy represents around 11 per cent of Synergy's total income (2009/10 to 2011/12).

Tariff adjustment payment

The largest of the subsidies is the 'tariff adjustment payment' which funds the 'glide path' that moves regulated tariffs to the level of cost reflective tariffs in the SWIS as calculated by OoE in 2009. According to the 2009/10 Budget Papers, funding this shortfall from the Consolidated Account helps to ensure:

- "..increased transparency, by fully disclosing the financial impact of keeping electricity tariffs below cost;
- improved accountability, by having the financial impact of a less than cost reflective tariff borne by the State and not the electricity suppliers; and
- market development, through competitively neutral electricity pricing."[146]

Customer related subsidies

The energy rebate provides an energy subsidy to people who are financially disadvantaged. The subsidy is intended to assist with the costs of buying energy of all types (electricity, gas, fuel oil, wood, etc.). However, for administrative simplicity, the subsidy is paid through Synergy and Horizon Power as a rebate on some electricity costs to residential customers who are holders of eligible concession cards.

[146] Department of Treasury and Finance (2009/10), State Budget Paper No. 3 – Fiscal and Economic Outlook, Appendix 8, p274

The costs to Synergy of the feed-in tariffs provided to customers who generate electricity from their own photovoltaic systems are also met by a CSO.

The dependent child rebate is a rebate against electricity bills and varies with the number of dependent children. This is available to holders of eligible concession cards.

The Hardship Efficiency Programme (**HEP**) is a government hardship assistance programme that complements the Hardship Utility Grants Scheme (**HUGS**). HEP helps customers in hardship to increase energy efficiency within their home through a combination of energy smart advice and education and appliance upgrades.

The charitable organisation rebate provides for eligible 'not for profit' organisations to be charged a lower electricity tariff.

The air conditioning allowance provides, upon application, eligible seniors with an electricity rebate equivalent to the cost of 200 kilowatt hours of electricity per applicable month to offset the electricity costs associated with operating an air conditioner in the hottest parts of the State.

Revenue from Large Commercial Customers

As noted in Section 9 above, Synergy's large commercial customers bilaterally negotiate their electricity supply directly with Synergy and as such, these customers are not charged regulated retail electricity tariffs

Other Revenue

Synergy also retails over 35 per cent of the gas sold to contestable customers in the SWIS. Contestable gas customers are those, typically businesses, who consume more than 180 GJ per annum which is equivalent to an annual gas charge of $4,000.[147]

To ensure electricity retail tariffs are cost reflective it will be important for the inquiry to ensure that the costs of retailing electricity and gas are separately identified, particularly where common billing or customer contact systems are used to service both gas and electricity customers.

Synergy also receives minimal income from other sources such as interest received and asset disposals. In 2009/10 this amounted to $11.4 million.

Types of Retail Expenses

Synergy's expenditure is predominantly associated with wholesale electricity purchases (energy and capacity); network access costs; renewable energy certificate procurement; and costs associated with delivering its retail services. Synergy also incurs costs in network access charges to Western Power and market fees to the IMO. Another element of Synergy's costs is its retail margin, to compensate shareholders (the government) for the level of systematic risk undertaken by the retailer.

[147] Alinta (2011) , verbal confirmation of amount to ERA in April 2011

Wholesale Electricity Purchases

In undertaking its wholesale electricity procurement, Synergy has to undertake purchases in separate capacity and energy markets on the WEM. The key risk factors for Synergy involve timing and quantity risk.

The majority of electricity sales in the SWIS are undertaken through bilateral contracts and the largest bilaterally traded quantities are between Verve Energy and Synergy. Short-term adjustments around these bilateral positions are made through the STEM.

Vesting Contract

Under the replacement vesting contract, Synergy purchases energy and capacity from Verve Energy. The contract prices and volumes are confidential and there is no obligation to publish any ongoing documents about the contract. Further details on the replacement vesting contract provided in the Authority's recent report to the Minister for Energy.[148]

As Synergy is currently prevented from engaging in generation activities itself,[149] the remainder of the wholesale electricity required by Synergy (outside of the replacement vesting contract) for its retail customers is procured through commercial means, either bilaterally negotiated commercial contracts or through the STEM. Synergy has noted that the "replacement of the Verve Vesting Contract with the prescribed Replacement Vesting Contract has resulted in increases in the energy and capacity costs charged by Verve".[150]

Other Commercial Contracts

For energy supply and Capacity Credits not covered by the replacement vesting contract, Synergy procures from the commercial sector. Synergy's supply procurement process may include an expression of interest stage where Independent Power Producers (and/or Verve Energy) are able to engage with Synergy to discuss how Synergy's requirements could be met by available existing capacity and proposed new capacity. Synergy is then able to progress to a tender phase if required. Examples of supply contracts tendered using this process are noted in Synergy's Statement of Corporate Intent (**SCI**), published annually on its website. For example Synergy's 2010/11 SCI, contains details of a contract for 638 MW of Capacity Credits and associated energy from Verve Energy's generation portfolio for a 15 year supply term, commencing late in 2011.

Electricity Market Trading

Energy Market

Synergy's trading position on the STEM is based on its demand forecasts, which primarily reflect the demand profiles of its non-contestable customers (small use residential or business customers). Unlike retailers supplying industrial loads, Synergy's load is largely temperature dependent and the accuracy of its forecast demand (and resulting position taken in the STEM) is reliant on the accuracy of the day-ahead weather forecast.

As Synergy's demand is primarily from non-contestable customers, it will typically require greater surety of supply for peak demand periods than retailers supplying industrial loads. Synergy meets any shortfall in the level of contracted energy (relative to forecast demand)

[148] ERA (2011), 2010 Annual Wholesale Electricity Market Report to the Minister for Energy

[149] Electricity Corporations Act 2005, section 47(1)

[150] Synergy Quarterly Report: 1 October 2010 – 31 December 2010

either through additional supplies from bilateral contracts (long or short term)[151] or through the STEM. The maximum price that Synergy would be willing to bid in the STEM, to ensure supply, will reflect the price specified in its bilateral contracts for additional energy supplies. Deviations between Synergy's net position (bilateral and STEM) and actual real-time demand will be physically balanced by System Management and financially settled through the Balancing Market. There are price and quantity risks associated with being exposed to the Balancing Market.[152]

Capacity Market

In order to determine the efficient revenue requirement for Synergy, it will be necessary to assess how Synergy deals with its IRCR requirements and its risk exposure in its procurement of Capacity Credits. As a retailer (without generation assets), Synergy can procure Capacity Credits to settle its IRCR through bilateral contracts with generators (which may not be bundled with energy) or DSM providers,[153] which enables Synergy to forward hedge its anticipated IRCR. Synergy may also obtain uncontracted Credits that are traded via the IMO at an administered price, based on the MRCP for the current year.

Renewable Energy Procurement

In past years, Synergy had annual targets for the procurement of (then) Renewable Energy Certificates (**RECs**). In 2009/10, Synergy's REC liability was $24.2 million, representing 1.2 per cent of Synergy's cost of sales.[154] While there is no regulatory oversight of Synergy's procurement of renewable energy, Synergy does require Ministerial approval if the value of an electricity supply contract exceeds $50 million.[155]

Under the Large-scale Renewable Energy Target/Small-scale Renewable Energy Scheme (**LRET/SRES**) scheme introduced in January 2011, Synergy is required to procure and surrender:

- LGCs (Large-scale Generation Certificates) to meet the Renewable Power Percentage (**RPP**); and

[151] Long term bilateral contracts typically have supply tranches (a base 'take-or-pay' tranche and options on additional supply tranches) with differing prices.

[152] If Synergy underestimates its demand relative to its net (bilateral and STEM) position, it must purchase electricity through the Balancing Market at the Marginal Cost Administrative Price (MCAP). This price is set on the basis of a formula that has variability in the inputs and the MCAP used for financial settlement only becomes known to participants the day after the STEM trading day. For retailers, the price is then multiplied by the relevant quantity, known as the Authorised Deviation Quantity (ADQ), to calculate the financial settlement for purchases or sales in the Balancing Market. For retailers, ADQ is the deviation between the participants scheduled demand and their actual load. For Synergy, as the primary retailer (which supplies small loads), its ADQ is calculated as the residual between total system load and total metered load for each trading interval. This is known as the 'wholesale notional meter'. Synergy will then be informed of its exact ADQ when the IMO finalises the financial settlement for Balancing, which is typically around six weeks after the trading day. If Synergy overestimates its actual demand, the excess electricity 'spills' into the Balancing Market, where it is sold at a discount (given the specified Market Rules formula) to the STEM purchase price. Note that under market design changes (due to be implemented in 2012), 'rebidding' on the day will be allowed with a new competitive market for Balancing.

[153] Synergy is registered in the WEM for the provision of DSM and has certified Capacity Credits of 40MW for the 2011/12 Capacity Year.

[154] In Synergy's financial statements, the REC's liability is recognised at the average market price of REC purchased for the period.

[155] Synergy requires Ministerial approval, if the value of the contract or agreement exceeds $20 million, or exceeds $50 million for the supply of electricity and/or gas (indexed annually by CPI, commencing 1 July 2009). These thresholds are set under s.68 of the *Electricity Corporation Act 2005* and the *Electricity Corporations (Transactions Exempt from Ministerial Approval) – Order 2008,* Government Gazette No. 137, 8 August 2008.

- STCs (Small-scale Technology Certificates) to the Small-scale Technology Percentage (**STP**).

Synergy manages its liability by entering into bilateral electricity supply contracts with renewable energy power producers, purchasing certificates in the open market, paying a fixed penalty for not meeting the target liability,[156] or purchasing STCs from the STC Clearing House at a fixed price (currently $40 per certificate). The price and quantity risks to Synergy are greater under the current scheme than under the previous scheme, as it must manage its liabilities for both LGCs and STCs.

Since market commencement, a large proportion of new generation capacity entering the WEM has been supported through bilateral contracts with Synergy.[157] In its 2010/11 Statement of Corporate Intent, Synergy noted that "in developing an optimised and secure supply portfolio. RET (**Renewable Energy Target**) requirements are meet by a range of existing and, if financially viable, new technologies (e.g. wave, geothermal)." Synergy has previously procured RECs from a number of large and small scale renewable projects, and in particular from wind farms. A recent example of renewable energy procurement is also given in Synergy's 2010/11 SCI, e.g. a 15 year contract to underpin the development of the 206 MW Collgar wind farm, near Merredin.[158]

Network Fees

Synergy is the largest of Western Power's wholesale distribution customers. Synergy pays its network distribution charges out of the revenue collected from households and small to medium business customers in the SWIS. In 2010/11, a CSO payment of $282.9 million[159] was made to Synergy and the gazetted TEC amount was $175.7 million.[160]

The Authority is currently assessing Western Power's third Access Arrangement, with a final determination on Western Power's network charges anticipated by the end of June 2012. For the purposes of the Synergy inquiry, in which the Authority is required to recommend cost reflective tariffs for Synergy for the four-year period 2012/13 to 2015/16, the Authority will need to make an assumption around the expected level of network charges for modelling purposes over the review period. This assumption should not be taken as indicative of any outcome from the Western Power Access Arrangement determination.

Billing and Customer Service Management

As an electricity retailer, Synergy is responsible for transforming meter reading data from Western Power into electricity bills for customers within the SWIS and then collecting payments. This includes functions such as billing, payment collection, customer services such as provision of information, financial management and reporting.

[156] $65 per REC not surrendered for the 2010 compliance year and $65 per LGC/STC not surrendered for 2011 and future years.

[157] As a result of Synergy's Supply Procurement program required under the Displacement Mechanism in the original Vesting Contract (2006).

[158] Synergy (2010), Statement of Corporate Intent 2010/11, this contract was worth an estimated $1.5 billion.

[159] Department of Treasury and Finance (2011), 2001/12 Budget Paper No. 3, Appendix 8, p293.

[160] Government Gazette (2009), No. 208, 17 November 2009, p4639.

Retail Margin

A retail margin compensates the retail business and ultimately the investors in the retail business, for the systematic risks that the retail business faces.[161] Systematic risk is generally considered unavoidable and results from exposure to overall economic or market conditions. As an electricity retailer, Synergy faces systematic risks such as rising inflation or changes in interest rates. The retail margin seeks to compensate investors for this systematic risk as it cannot be reduced or eliminated through portfolio diversification.

The original Vesting Contract (2006) included a predetermined and fixed margin on customer sales which Synergy used to fund its retail operations (including an appropriate return on investment in the retail electricity sector). This was included as part of the Netback Mechanism arrangements of the original Vesting Contract (2006). Under the Netback Mechanism, Verve Energy received the residual of Synergy's revenue after all other costs (including the TEC) have been deducted. An assumption regarding Synergy's retail costs and margin was made as part of the current calculations behind the replacement vesting contract and CSO 'tariff adjustment payment' to Synergy.

[161] Investors in an electricity retail business will also experience non-systematic risk, e.g. uncertainty over energy costs associated with changing weather conditions, and it is assumed that these risks can be reduced or eliminated through portfolio diversification.

Appendix C. Synergy's Current Tariffs

Synergy's current tariffs listed in: WA Energy Operator (Powers) Act 1979 – Energy Operators (Electricity Retail Corporation) (Charges) By-laws 2006, as at 1 July 2011, (plus the SmartPower residential time-of-use plan):

Table 39 Synergy's Current Tariffs

A1 Residential Tariff	
Supply charge – cents per day	40.14
Supply charge for additional homes – cents per day	31.17
Electricity charge – cents per unit	21.87
B1 Hot Water tariff	
Supply charge – cents per day	20.80
Supply charge for additional homes – cents per day	20.80
Electricity charge – cents per unit	11.49
SM1 SmartPower time-of-use plan *(Note: this is not a regulated tariff)*	
Supply charge – cents per day	40.14
Electricity charge – cents per unit	
Off peak (all year, all week) 9pm – 7am	11.32
Weekend shoulder (all year) 7am – 9pm	17.77
Summer (October – March) weekdays shoulder 7am – 11am, 5pm – 9pm	21.44
Summer (October – March) weekdays peak 11am – 5pm	42.15
Winter (April – September) weekdays shoulder 11am – 5pm	21.44
Winter (April – September) weekdays peak 7am – 11am, 5pm – 9pm	42.15
C1 Community Service tariff	
Supply charge – cents per day	36.66
Electricity charge – cents per unit	
First 20 units per day	19.98
Between 21 – 1650 units per day	25.04
More than 1650 units per day	22.59
D1 Charitable Accommodation tariff	
Supply charge – cents per day	36.66
Supply charge for additional residences – cents per day	28.46
Electricity charge – cents per unit	19.98
K1 Home Business tariff	

Supply charge – cents per day		40.14
Electricity charge – cents per unit		
	First 20 units per day	21.87
	Between 21 – 1650 units per day	27.41
	More than 1650 units per day	24.75
L1 Business tariff (less than 50 MWh p.a.)		
Supply charge – cents per day		38.06
Electricity charge – cents per unit		
	First 1650 units per day	25.04
	More than 1650 units per day	22.59
L3 Business tariff (greater than 50 MWh p.a.)		
Supply charge – cents per day		49.32
Electricity charge – cents per unit		
	First 1650 units per day	32.40
	More than 1650 units per day	29.25
M1 Business tariff (suitable for larger customers, connecting at high voltage)		
Supply charge – cents per day		45.46
Electricity charge – cents per unit		
	First 1650 units per day	28.86
	More than 1650 units per day	25.92
R1 Business time-of-use tariff (less than 50 MWh p.a.)		
Supply charge – cents per day		156.16
Electricity charge – cents per unit		
	Peak (Monday – Friday, 8am – 10pm)	27.41
	Off-peak (overnight and weekends)	8.45
R3 Business time-of-use tariff (greater than 50 MWh p.a.)		
Supply charge – cents per day		214.09
Electricity charge – cents per unit		
	Peak (Monday – Friday, 8am – 10pm)	37.48
	Off-peak (overnight and weekends)	11.54
S1 Large Business Demand Low Voltage tariff		
Minimum charge – dollars per day		$400.71
Electricity charge – cents per unit		
	Peak (Monday – Friday, 8am – 10pm)	14.56
	Off-peak (overnight and weekends)	9.21
Demand charge - cents per day/kW max demand		101.78
T1 Large Business Demand High Voltage tariff		

Minimum charge – dollars per day	$568.70
Electricity charge – cents per unit	
Peak (Monday – Friday, 8am – 10pm)	14.65
Off-peak (overnight and weekends)	9.74
Demand charge - cents per day/kW max demand	100.19
W1 Tariff - Traffic Light installations	
Charge per kilowatt of installed wattage – dollars per day	$4.39
Fee – Supply of electricity to standard railway crossing lights	
Charge - cents per day	61.3044

Z Tariffs – Street lights and auxiliary lighting

Tariff	Wattage	Type	Midnight Switch-off (Obsolescent) Cents per day	1:15am Switch-off Cents per day	Dawn Switch-off Cents per day
Street lighting on current offer and for existing services					
Z.01	50	Mercury Vapour	34.7015	35.4444	38.1294
Z.02	80	Mercury Vapour	40.8649	41.7769	45.9647
Z.03	125	Mercury Vapour	50.5409	52.1788	58.0890
Z.04	140	Low Pressure Sodium	51.7229	53.4115	60.1999
Z.07	250	Mercury Vapour	62.7160	65.9074	77.8122
Z.10	400	Mercury Vapour	92.9086	97.7720	116.3469
Z.13	150	High Pressure Sodium	47.8728	49.6290	59.4569
Z.15	250	High Pressure Sodium	70.9733	74.7559	89.3456
Z.18	Per kW	Auxiliary lighting in public places	203.3285	214.6254	259.0871
Street lighting for existing services only					
Z.05	250	Mercury Vapour	81.2741	84.4487	96.3703
Z.06	400	Mercury Vapour	111.4837	116.3469	134.8375
Z.08	250	Mercury Vapour 50% EC cost	71.9865	75.1275	87.0829
Z.09	250	Mercury Vapour 100% EC cost	81.2741	84.4487	96.3703
Z.11	400	Mercury Vapour 50% EC cost	102.1962	107.0764	125.5838
Z.12	400	Mercury Vapour 100% EC cost	111.4837	116.3469	134.8375
Z.14	150	H.P. Sodium	73.8609	75.5832	85.3773
Z.16	250	H.P. Sodium 50% EC cost	84.8708	88.6871	103.2431
Z.17	250	H.P. Sodium 100% EC cost	98.7345	102.6014	117.1743
Z.51	60	Incandescent	34.7015	35.4444	38.1294
Z.52	100	Incandescent	34.7015	35.4444	38.1294
Z.53	200	Incandescent	40.8649	41.7769	45.9647
Z.54	300	Incandescent	50.5409	52.1788	58.0890
Z.55	500	Incandescent	81.2741	84.4487	96.3703
Z.56	40	Fluorescent	34.7015	35.4444	38.1294
Z.57	80	Fluorescent	40.8649	41.7769	45.9647
Z.58	160	Fluorescent	57.1604	57.9539	67.2415

Appendix D. Synergy's Demand Forecasts

[redacted]

Appendix E. Synergy's Rate of Return

1. Assets are often financed by a combination of debt and equity. Thus, the returns from an asset must compensate both the providers of debt and the equity holders. For this reason, the term "Weighted Average Cost of Capital" (**WACC**) is often used to refer to the average cost of debt and equity capital, weighted by a proportion of debt and equity to reflect the financing arrangements for the assets, i.e.,

$$WACC = R_e \frac{E}{V} + R_d \frac{D}{V}$$

Where R_e is the return on equity, which is estimated using the Capital Asset Pricing Model (**CAPM**), R_d is the cost of debt. E is the share of equity and V is the share of debt such that $V = E + D$.

2. The WACC is an estimate of the post-tax (cash) return on assets. Calculating the WACC consists of:

- determining the (post tax) Rate of Return on equity R_e;
- determining the Cost of Debt R_d;
- determining the financing structure (D/V and E/V); and
- other WACC parameters which directly affect the above parameters.

3. The above WACC formula is widely known as the post-tax (Vanilla) WACC formula because the formula, in its simplest form, requires all potential costs and benefits to be reflected in the cash flows. While all regulators of utility industries in Australia use the CAPM to estimate the cost of capital, there is no clear precedent on the form of the WACC to be used (i.e. pre-tax or post-tax, real or nominal).

The Nominal Post-Tax WACC Formula:

4. In the absence of an imputation tax system, the nominal post-tax form of the Weighted Average Cost of Capital (WACC) is expressed as below:

$$WACC_{\text{nominal post-tax}} = E(R_e) \times \frac{E}{V} \times + E(R_d) \times \frac{D}{V}(1 - T_c)$$

where:

- $E(R_e)$ is the nominal post-tax expected rate of return on equity – the cost of equity;
- $E(R_d)$ is the nominal pre-tax expected rate of return on debt – the cost of debt;
- E/V is the proportion of equity in the total financing (which comprises equity and debt);
- D/V is the proportion of debt in the total financing; and
- T_c is the tax rate.

5. The Australian tax system provides credits to shareholders for tax already paid at the corporate level, to avoid double taxation of the same income stream. In this circumstance, the nominal post-tax WACC formula needs to be modified to reflect the additional element of shareholders' return available through the taxation system. This is an estimate of the post-tax return on assets in the presence of an imputation credit tax system:

$$WACC = E(R_e) \times \frac{E}{V} \times \frac{1-T_c}{(1-T_c(1-\gamma))} + E(R_d) \times \frac{D}{V}(1-T_c)$$

where γ (gamma) is the value of franking credits created (as a proportion of their face value).

The Nominal Pre-Tax WACC Formula:

6. This is an estimate of the pre-tax return on assets, which can be obtained by dividing the right hand side of the formula for the above nominal post-tax return on assets by the component $(1-T_c)$, which can be expressed as:

$$WACC = E(R_e) \times \frac{E}{V} \times \frac{1}{(1-T_c(1-\gamma))} + E(R_d) \times \frac{D}{V}$$

7. The following sections are devoted to an analysis for each of the WACC parameters on which the rate of return is estimated for Synergy for the purpose of this inquiry. Each of the WACC parameters is discussed in turn below.

Nominal Risk Free Rate

8. The risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments (i.e. no risk of default). The Australian Commonwealth Government bonds (**CGS**) are widely used as a proxy for the risk free rate in Australia. CAPM theory does not provide guidance on the appropriate proxy for the risk free rate. In Australia, regulators' current practice is to average the observed yield on the CGS for a period of 20 trading days as close as feasible before the day the decision is made.

9. In its recent decision on DBNGP's proposed access arrangement, the Authority is of the view that there are strong grounds for matching the assumption of term to maturity with the regulatory period, which is generally 5 years. As such, 5-year term to maturity for a nominal risk free rate will also be adopted in this inquiry. The Authority considers the estimated nominal risk free rate of return should be 3.42 per cent using yields from the 5-year Commonwealth Government bonds reported by the RBA, as at 30 April 2012.

Market Risk Premium

Introduction

10. The market risk premium (**MRP**) is the average return of the market above the risk free rate. In other words, it is the premium that investors demand for investing in a market portfolio relative to the risk-free rate.

$$MRP = R_m - R_f$$

where R_f is the risk-free rate.

11. There are several ways to estimate the equity risk premium, though there is no general agreement as to the best approach. The three approaches usually used are as follows.

- The first approach is the historical equity risk premium approach, which is a well-established method based on the assumption that the realised equity risk premium observed over a long period of time is a good indicator of the expected equity risk premium. This approach requires compiling historical data to find the average rate of return of a country's market portfolio and the average rate of return for the risk-free rate in that country.
- The second approach for estimating the equity risk premium is the dividend discount model based approach or implied risk premium approach, which is implemented using the Gordon growth model (also known as the constant-growth dividend discount model). For developed markets, corporate earnings often meet, at least approximately, the model assumption of a long-run trend growth rate. As a result, the expected return on the market is the sum of the dividend yield and the growth rate in dividends. The equity risk premium is therefore the difference between the expected return on the equity market and the risk-free rate.
- The third approach is the direct approach or survey approach. A panel of finance experts is asked for their estimates the mean response is taken.

12. The Authority considered that cash flow based measures of the MRP (such as the Dividend Growth Model) are subject to a number of limitations:

- They provide highly variable forward looking estimates of the MRP.
- They are sensitive to small changes in assumptions.
- There is a relative lack of data sources of these estimates.

13. The AER also noted that there are inherent problems in any DGM[162] such as:

- reliance on contentious assumptions, such as:
  - markets are perfectly priced at all times; and
  - forecast dividend distributions accurately reflect market expectations;
- forecasts are highly variable:
  - small, plausible changes to inputs and assumptions produce large changes in MRP estimates; and
  - even if consistent inputs are used, implausibly large changes in MRP are estimated across short periods of time.

14. As a result, among these three, Australian regulators' current approach is to adopt the first approach, using historical data on equity premiums, and the survey approach, together with observations on the Australian financial market to provide the estimate of the MRP.

[162] The Australian Energy Regulator (March 2010), Final Decision, Access Arrangement Proposal on ACT, Queanbeyan and Palerang Gas Distribution Network, page 61

Considerations of the Authority

15. In previous decisions, the Authority was of the view that it is appropriate to consider a wide range of the evidence for the forward-looking long-term estimates of the MRP, including:

    - an estimate of the historical equity risk premium for the period for 1883 – 2010 by Associate Professor Handley in January 2011;[163]
    - surveys of market risk practice; and
    - the Authority's approach and other Australian regulators' current practice.

16. The Authority will follow the same approach to determine the appropriate estimate of the MRP for this inquiry.

The Method of Using Historical Data on Equity Risk Premium

17. The market risk premium is the required return, over and above the risk free rate, on a fully diversified portfolio of assets. It is the current practice of regulators across Australia to estimate the MRP using historical data on equity premia, together with other approaches as mentioned above.

18. Australian regulators have consistently applied a MRP of 6 per cent in their decisions, except for the AER's decisions after its review of WACC parameters released in May 2009. It is noted that a MRP of 6 per cent was first adopted in Australia by the ACCC[164] and the Victorian Office of the Regulator General. A MRP range of 4.5-7.5 per cent was derived on the basis of consultant work prepared by Professor Davies at the University of Melbourne, where the upper bound of this range was based on historical estimates and the lower bound was based on cash flow measures.[165] As such, the mid-point of that range (6 per cent) was adopted. Subsequently, Australian regulators have consistently applied a MRP of 6.0 per cent, which is estimated using historical data on equity premia.

19. In its previous regulatory decisions, with regard to the estimates of the MRP using historical equity risk premium, the Authority relied on the studies by Associate Professor Handley at the University of Melbourne prepared for the AER. In these studies, Handley used the observed yields on 10-year Commonwealth Government bonds as the proxy for the nominal risk free rate.

---

[163] Handley, 2011, "An estimate of the historical equity risk premium for the period for 1883 – 2010", A report for the Australian Energy Regulator, January 2011.

[164] ACCC, Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System – Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System – Access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System, Final Decision, 6 October 1998.

[165] ORG, Access arrangements – Multinet Energy Pty Ltd and Multinet (Assets) Pty Ltd – Westar (Gas) Pty Ltd and Westar (Assets) Pty Ltd – Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd , Final decision, October 1998.

20. As previously discussed, the Authority has adopted the 5-year term to maturity for the risk free rate. As such, for consistency purpose, the Authority considers that it is more appropriate to adopt a 5-year term to maturity for the estimates of the MRP using historical equity risk premia.

21. The Authority is aware that the observed yields on 5-year Commonwealth Government bonds have become available since July 1969. This was also confirmed by Handley in his report to the AER in 2008.[166]

22. The Authority has constructed a data set of 40 years, from 1969 to 2011, inclusive.

23. An equity market index was used as a proxy for the market return. This data is obtained using a Bloomberg.[167] The series was based on the All Ordinaries Accumulation Index, a value weighted index made up of the largest 500 companies as measured by the market caps that are listed on the Australian Stock Exchange. This index captures a market return comprising dividends and capital gains.

24. For consistency, the yearly index value is the arithmetic average of the daily closing index values during the corresponding December.

25. The estimate of Commonwealth Government bond yields (or the risk free rate) is the yields on 5-year term Treasury Bonds. The risk free proxy series from 1969 to 2011 were collected from the Reserve Bank of Australia website.

26. The MRPs were calculated as the difference between the historical market return and the opening Treasury bond yield. This means that:

$$MRP_t = E_t - Y_{t-1};$$

where:

- MRP_t is the market risk premium for year t;
- E_t is the nominal equity return for year t; and
- Y_{t-1} is the 5-year Commonwealth Government bond yield for year $(t-1)$.

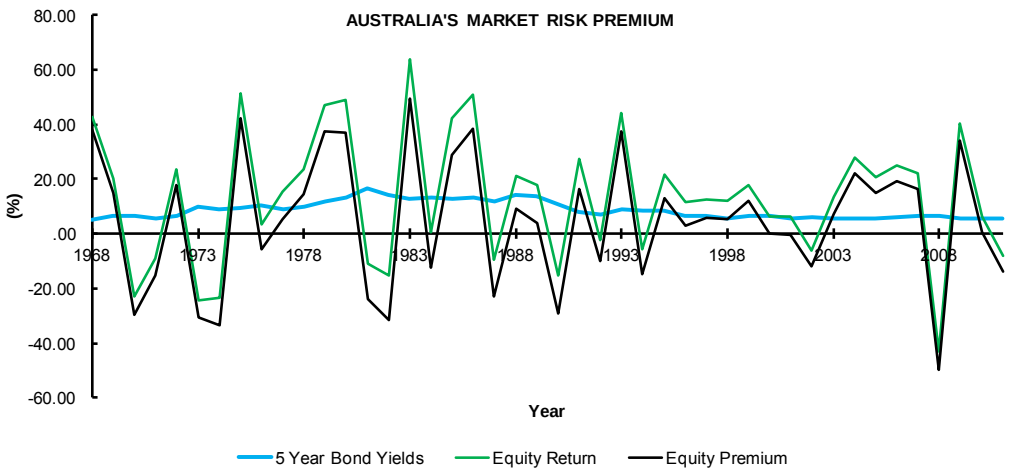
Figure 9 Australia's Market Risk Premium 1969 - 2011 (%)

27. Figure 12 below presents the estimates of Australia's MRP for the period from 1969 to 2011.

[166] Handley, 2008, "A Note on the Historical Equity Risk Premium", A report for the Australian Energy Regulator, 17 October 2008, page 4.

[167] The ticker of *ASA30 Index* and the field of *PX_LAST* were used to obtain the data.

Figure 9 Australia's Market Risk Premium 1969 - 2011 (%)



Source: RBA, Bloomberg, and ERA Analysis

28. Table 40 below presents the estimates of Australia's MRP for the period from 1969 to 2011 over different periods.

Table 40 Estimates of Australian Market Risk Premium, 1969 - 2011

Period	No. of years	MRP Per cent	MRP [including imputation credit][168] Per cent
1968 - 2011	44	4.7	5.2
1980 - 2011	32	4.8	5.6
1988 - 2011	24	3.8	5.0

Source: ERA Analysis

29. From the above analysis, given the high level of imprecision due to a nature of the estimates of the MRP using historical equity risk premium, the Authority is of the view that the estimate of the MRP, using 5-year nominal risk free rate of return, is 6 per cent.

[168] Assumed values of imputation credit were obtained from AER, the Weighted Average Cost of Capital Review, Final Decision, May 2009, Table 7.2, page 209.

The Survey Method

30. The Authority also observes that 6.0 per cent is the market risk premium value most commonly used by Australian market practitioners. Surveys of market risk practice show that 47 per cent of market practitioners apply a MRP of 6.0 per cent, while 69 per cent apply a value of 6.0 per cent or less. Only 26 per cent of market practitioners apply values of MRP more than 6.0 per cent.[169] However, the Authority is aware that this information preceded the global financial crisis in 2008.

31. Surveys in 2009[170] and 2010[171] show that the average MRP adopted by market practitioners was approximately 6 per cent. These findings are similar to the market surveys prior to the Global Financial Crisis.[172]

32. In addition, evidence from broker reports indicates that the current market practice is to adopt an MRP of approximately 6 per cent. In addition, a recent report from AMP Capital Investors indicates that its forward-looking MRP is lower than 6 per cent.[173]

33. Anthony Asher conducted a survey of MRP estimates by a number of Australian actuaries in February 2011. There were 58 respondents. Most of the respondents were associated with Investment and Wealth Management, Insurance, Superannuation and Banking. The study reported that, on average, respondents had about 15 years of experience as actuaries. The survey found that the average MRP expected over the next 12 months was 4.7 per cent, while the average expected over the next ten years was 4.9 per cent. The author noted that the standard deviation of the former estimate is 2.5 per cent, and of the latter 2.0 per cent. In these estimates, franking credits were taken into account.[174]

---

[169] G. Truong, G. Partington and M. Peat, 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008, page 155.

[170] Fernandez and Del Campo, Market Risk Premium used by Professors in 2008: A Survey with 1400 Answers, IESE Business School Working Paper, WP-796, May 2009, page 7.

[171] Fernandez and Del Campo, Market Risk Premium Used in 2010 by Analysts and Companies: A Survey with 2400 Answers, IESE Business School, 21 May 2010, page 4.

[172] For example, see Truong, Partington and Peat (2008), 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008, p.155. KPMG (2005), *Cost of Capital – Market Practice in relation to Imputation Credits.* Capital Research (2006), *Telstra's WACC for network ULLS and the ULLS and SSS businesses – Review of reports by Professor Bowman,* Associate Professor Neville Hathaway.

[173] Oliver, Shane, 2011, *Why are Australian shares lagging? Will it continue?* AMP Capital Investors, January 2011, page 2.

[174] Asher, A. (2011), "Equity Risk Premium Survey: Results and Comments", *Actuary Australia,* 161, July 2011, pp. 13-15.

34. In the most recently released article, "*Market Risk Premium Used in 56 Countries in 2011: A Survey with 6,014 Answers*" by Pablo Fernandez, Javier Aguirreamalloa and Luis Corre from IESE Business School, University of Navarra, the authors provided an analysis of the results of an international survey on the MRP in March and April 2011. Of the 3,998 survey responses that provided an estimate of the MRP, 40 were from Australia and offered an estimate of the MRP for the Australian equity market. The average of these 40 estimates of the Australian MRP was 5.8. Of the 40 responses received for Australia, 15 were from academics, 21 from analysts and 4 from managers of companies. The average of the estimates of the MRP received from academics was 6.2, from analysts 5.4 and from managers 6.5. It is noted that, while the overall average for Australia was 5.8, the median was significantly lower, at 5.2.[175]

Current Practice by Australian Regulators

35. The Authority has consistently adopted the point estimate of the MRP of 6 per cent in its regulatory decisions.[176] For the current access arrangement for Western Power, the Authority was of the view that the range of the MRP was between 5 per cent and 7 per cent, and that the point estimate of 6 per cent, being the average of the two, was appropriate.[177]

36. The AER had adopted a MRP of 6 per cent since 2011 in its draft decision on Envestra's access arrangement proposal for the South Australian gas network, released in February 2011.[178] The AER has since then applied the MRP of 6 per cent for regulated businesses.

37. IPART has used a market risk premium range of 5.5 per cent to 6.5 per cent in its recent determinations, such as for metropolitan and outer metropolitan bus services in December 2009, the CityRail determination, and recent determinations on prices charged by Sydney Catchment Authority and Hunter Water. IPART argues that deriving the MRP from a long-term historical time series remains appropriate. IPART also considers that relying on a long-term historical time series adequately takes into account any impact on excess returns of recent market events, such as the global financial crisis.

38. The Queensland Competition Authority has also used 6.0 per cent for the MRP in the draft determination for Queensland Rail in December 2009. QCA argued that it did not lower the MRP when the market conditions at the time led some stakeholders to seek a reduction – therefore increasing the MRP now would be inconsistent with its past practice that sets the MRP at a level to encourage investment over the medium term, and not in response to short-term market fluctuations.

---

[175] The Australian Competition and Consumer Commission, 2011, *Network,* Issue 41, September 2011, page 11.

[176] For example, see The Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, 31 October 2011, page 137.

[177] The Economic Regulation Authority, 2009, Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 4 December 2009, page 236.

[178] Australian Energy Regulator, February 2011, Draft Decision, Envestra Ltd. – Access Arrangement proposal for the SA gas network, pages 83-92.

Recent Developments in the Australian Financial Market

39. The Authority is aware of current developments in the financial markets both in Australia and overseas. However, the Authority is of the view that the investors' expectations of the long-run forward-looking MRP is unlikely to change frequently in response to any developments in the financial markets in the short term.

Conclusion

40. Based on the above analyses, the Authority is of the view that a MRP of 6 per cent is appropriate. This is consistent with the view of some other Australian regulators, including the AER, IPART and QCA, that this is the best estimate of a forward-looking long-term MRP.

41. The Authority considers that a reasonable point estimate for the MRP is 6 per cent.

Equity Beta

Introduction

42. The systematic risk (beta) of a firm is the measure of how the changes in the returns to the firm's stock are related to the changes in returns to the market as a whole. Systematic risks are those risks that cannot be costlessly eliminated through portfolio diversification, such as unexpected changes in real aggregate income, inflation and long-term real interest rates.

43. The most common formulation of the CAPM estimates directly the required return on the equity share of an asset as a linear function of the risk free rate plus a component to reflect the risk premium that investors would require over the risk free rate:

$$R_e = R_f + \beta_e \left(R_m - R_f \right)$$

where R_e is the required rate of return on equity, R_f is the risk-free rate, β_e is the equity beta that describes how a particular portfolio i will follow the market and is defined as $\beta_e = \mathrm{cov}\left(r_i, r_M\right) / \mathrm{var}\left(r_M\right)$; and $\left(R_m - R_f\right)$ is the market risk premium.

44. The above equation reveals that the equity beta of a particular asset will scale the MRP up (when its value is greater than one) or down (when its value is lower than one) to reflect the risk premium, which is over and above the risk-free rate, that equity holders would require to hold that particular risky asset in the investor's well-diversified portfolio.

Considerations of the Authority

45. In the Final Decision for the current access arrangement for Western Power, released in December 2009, the Authority adopted a range for the estimate of equity beta of network businesses of 0.5 to 0.8. The Authority was of the view that this range was consistent with the analysis presented by the AER in its 2009 WACC Review, based on Henry's empirical study, which suggests an equity beta of between 0.41 and 0.68.

46. The Authority considers that any empirical study estimating equity beta experiences a high level of imprecision. As such, the Authority is of the view that it is appropriate to take a conservative approach with regards to the estimates of equity beta. In the Draft Decision on Western Power Network's access arrangement, the Authority adopted the equity beta of 0.65.

47. For the purpose at hand, the Authority requires an estimate of the equity beta applying to generators (for the LRMC analysis) and to electricity retailers (for the retail margin analysis). The Authority notes that the most recent work relating to the equity beta applying to generators in the WEM is that undertaken by the Allen Consulting Group for the IMO.[179] On the basis of that work, the IMO adopts an equity beta of 0.83 for the purposes of calculating the Maximum Reserve Capacity Reserve Price. The Authority considers that this equity beta is appropriate for generation in Western Australia at the current time.

48. With regard to electricity retailing, the Authority notes that there is evidence to suggest that the equity beta for both types of businesses is similar.[180] The Authority also considers that an efficient new entrant to retailing in Western Australia would likely be a 'gentailer'. For these reasons, the Authority considers that it is reasonable to adopt the same equity beta for retailing for the purpose at hand.

Conclusion

49. In conclusion, the Authority is of the view that an equity beta of 0.83 is reasonable for the purpose of this report.

Benchmark Financing Structure: Debt versus Equity

50. Gearing is the relative proportion of debt to total capital value, and is used to weight the cost of debt and equity when calculating WACC. The relative proportions of debt, equity, and other securities that a firm has outstanding constitute its capital structure. The capital structure choices across industries are different. The same conclusion can be reached for the capital structure for companies within industries. For regulated industries, the benchmark capital structure is considered to be the gearing level of a benchmark efficient utility business.

51. For this Final Report, the Authority considers that it is appropriate to adopt the benchmark gearing of 40 per cent – in order to be consistent with the Allen Consulting Group study underpinning the equity beta (see above).

52. Given the evidence available before it, the Authority is of the view that the credit rating of BBB+ is appropriate for the purpose of this inquiry. This benchmark credit rating for electricity retailer is consistent with the Allen Consulting Group study underpinning the equity beta (see above).

---

179 Allen Consulting Group 2009, *WACC parameters update for the purpose of determining the maximum reserve capacity price*, www.imowa.com.au.

180 For example, IPART has chose to adopt the same equity beta for generation as for retailing in its 2010 retail determination (IPART 2010, *Review of regulated tariffs and charges for electricity 2010-13*, www.ipart.nsw.gov.au, p 238).

The Cost of Debt (R_d)

53. As discussed in its Discussion Paper on "Measuring Debt Risk Premium: A Bond-Yield approach" released in December 2010, the Authority is of the view that:

    - Bloomberg's estimates of fair value curves for BBB+ Australian corporate bonds with longer term to maturity of 7 years and 10 years are problematic; and
    - extrapolation from a 7-year term to a 10-year term is also problematic.

Estimating the Debt Risk Premium: A Bond-Yield Approach

54. The Authority is of the view that the bond-yield approach is appropriate for estimating the debt risk premium for the purpose of this inquiry.

55. The Authority has used this approach in its final decisions on Western Australia Gas Networks Access Arrangement released in February 2011 and on the Dampier to Bunbury Natural Gas Pipeline released in October 2011. The same method was also adopted in the draft decision on the proposed access arrangement for Western Power network, released in March 2011.

56. Table 41 below summarises a benchmark sample of Australian corporate bonds with the S&P credit rating of BBB band, including BBB-/BBB/BBB+, as at 30 April 2012.

57. The Authority considered two scenarios in estimating the debt risk premium using the bond-yield approach:

    - Scenario I - a full sample of 14 Australian corporate bonds;
    - Scenario II – a shortened sample excluding all bonds with BBB- credit rating;
    - Scenario III – a shortened sample excluding all bonds with less-than-5-year term to maturity; and
    - Scenario IV - a shortened sample excluding all bonds with BBB- credit rating and all bonds with less-than-5-year term to maturity.

58. For each of the two scenarios above, the following four weighted average methods were considered:

    - a simple average;
    - a term-to-maturity weighted average approach;
    - an amount-issued weighted average approach; and
    - a median approach.

59. The Authority considers that the estimated 5-year nominal risk-free rate of return should be 3.42 per cent, for the period until 30 April 2012. This nominal risk free rate is estimated for a 5-year CGS. The same principle is applied to estimate the risk free rate for Australian corporate bonds with more (or less) than 5-year term to maturity. The risk free rate for 5-year CGS must be adjusted to reflect the fact that bonds in the benchmark sample have longer (or shorter) than-5-year term to maturity.

Table 41 A Benchmark Sample of Australian Corporate Bonds with Credit Rating of BBB band as at 30 April 2012.

No.	Bond	Bloomberg Ticker	Maturity
1	BRISBANE AIRPORT CORP LT	EI620440 Corp	9/07/2019
2	DBCT FINANCE PTY LTD	EF461870 Corp	9/06/2016
3	NEXUS AUSTRALIA MGT	EI204253 Corp	31/08/2017
4	NEXUS AUSTRALIA MGT	EI204261 Corp	31/08/2019
5	CALTEX AUSTRALIA LTD	EI883417 Corp	23/11/2018
6	DBNGP FINANCE CO PTY	EI414656 Corp	29/09/2015
7	ENVESTRA VICTORIA PTY LT	EC866427 Corp	14/10/2015
8	GOODMAN AUSTRALIA INDUST	EI675822 Corp	19/05/2016
9	HOLCIM FINANCE AUSTRALIA	EJ096330 Corp	27/03/2015
10	LEIGHTON FINANCE LTD	EH911249 Corp	28/07/2014
11	SYDNEY AIRPORT FINANCE	EI308853 Corp	6/07/2015
12	SYDNEY AIRPORT FINANCE	EI684902 Corp	6/07/2018
13	MIRVAC GROUP FUNDING LTD	EI195249 Corp	15/03/2015
14	MIRVAC GROUP FINANCE LTD	EI414696 Corp	16/09/2016

Source: Bloomberg.

Table 42 Observed Yields, Adjusted Nominal Risk Free Rate, the Debt Risk Premium for BBB Band Australian Corporate Bond as at 30 April 2012.

No.	Bond	Term to maturity as at 30 April 2012 (years)	Observed yields (per cent)	Risk Free Rate (per cent)	Debt Risk Premium (per cent)
1	BRISBANE AIRPORT CORP LT	7.19	6.471	3.639	2.832
2	DBCT FINANCE PTY LTD	4.11	7.284	3.347	3.936
3	NEXUS AUSTRALIA MGT	5.33	6.946	3.479	3.467
4	NEXUS AUSTRALIA MGT	7.33	7.118	3.653	3.466
5	CALTEX AUSTRALIA LTD	6.56	6.325	3.583	2.742
6	DBNGP FINANCE CO PTY	3.41	6.820	3.325	3.494
7	ENVESTRA VICTORIA PTY LT	3.46	6.736	3.329	3.407
8	GOODMAN AUSTRALIA INDUST	4.05	7.161	3.346	3.815
9	HOLCIM FINANCE AUSTRALIA	2.91	5.822	3.293	2.528
10	LEIGHTON FINANCE LTD	2.24	7.254	3.297	3.957
11	SYDNEY AIRPORT FINANCE	3.18	6.211	3.307	2.904
12	SYDNEY AIRPORT FINANCE	6.18	6.784	3.553	3.231
13	MIRVAC GROUP FUNDING LTD	2.88	6.449	3.293	3.156
14	MIRVAC GROUP FINANCE LTD	4.38	6.759	3.359	3.400

Source: The Economic Regulation Authority's analysis.

60. For example, Row 2 from Table 42 shows that the nominal risk free rate for the DBCT Finance bond with 7.19 years to maturity is 3.639 per cent for the 20 trading period to 30 April 2012. By comparison, the nominal risk free rate for this company, which has been used to estimate the debt risk premium for this bond in the benchmark sample, is higher than the risk-free rate for a 5-year CGS of 3.42 per cent. This is consistent with the finance principle of risk and return trade-off: for longer investments with higher risks, then higher returns are required.

61. The debt risk premiums calculated under the different scenarios and different weighted average methods are summarised in Table 43 below.

Table 43 Debt Risk Premiums under Various Scenarios and Weighted Average Approach as at 30 April 2012, Per cent

Weighted Average Method	Scenario 1 (14 bonds)	Scenario 2 (9 bonds)	Scenario 3 (5 bonds)	Scenario 4 (3 bonds)	Simple Average of all 4 scenarios
Simple Average	3.310	3.172	3.148	2.935	3.141
Term to Maturity Weighted Average	**3.283**	**3.118**	**3.222**	**2.979**	**3.151**
Amount Issued Weighted Average	3.306	3.089	3.257	2.938	3.147
Median	3.403	3.156	3.231	2.832	3.156

Source: Economic Regulation Authority's Analysis

62. Consistent with previous decisions, the Authority is of the view that the term-to-maturity weighted average method is likely to reflect the current conditions in the market for funds. As such, the debt risk premium is calculated as a simple average of the two term-to-maturity weighted average scenarios.

63. As a result, for the 20-day trading period until 30 April 2012 for this Final Report, the Authority is of the view that a debt risk premium of 3.151 per cent is reasonable.

Inflation Rate

64. The current practice adopted by the Authority, and other regulators, to determining the expected inflation rate is to calculate a geometric mean of inflation forecasts by the RBA for the next two years and the mid-point estimate of the RBA's long-term inflation forecasts of 2.5 per cent for the remaining three years.

65. In the Draft Report, the Authority adopted Synergy's forecast inflation rate of 2.50 per cent.

66. However, the Authority has elected to revert to its own approach to estimating inflation for the purposes of this report. The latest inflation forecast is for an average inflation rate of 2.35 per cent – which is based on a geometric average of the following estimates from the RBA's May 2012 Statement on Monetary Policy:

- 2011/12: 1.25 per cent;
- 2012/13: 3.0 per cent;
- 2013/14 and thereafter: 2.5 per cent.[181]

Corporate Tax Rate

67. The Authority considers that a corporate tax rate of 30 per cent is appropriate for the purpose of this inquiry.

Value of Imputation Credits

Introduction

68. A full imputation tax system for companies has been adopted in Australia since 1 July, 1987. While Australia and New Zealand have full imputation tax systems (which are discussed below) many other countries have a partial imputation system, where only partial credit is given for the company tax.

69. Under the tax system of dividend imputation, a franking credit is received by Australian resident shareholders, when determining their personal income taxation liabilities, for corporate taxation paid at the company level. In a dividend imputation tax system, the proportion of company tax that can be fully rebated (credited) against personal tax liabilities is best viewed as personal income tax collected at the company level. With the full imputation tax system in Australia, the company tax (corporate income tax) is effectively eliminated if all the franking values are used as credits against personal income tax liabilities.

70. It is widely accepted that the approach adopted by regulators across Australia to define the value of imputation credits, known as "Gamma", is in accordance with the Monkhouse definition.[182] There are two components of Gamma:

    - the distribution rate (F): the rate at which franking credits that are created by the firm are distributed to shareholders, attached to dividends; and
    - theta (θ): the value to investors of a franking credit at the time they receive it.

71. As a result, the actual value of franking credits, represented in the WACC by the parameter 'gamma', depends on the proportion of the franking credits that are created by the firm and that are distributed, and the value that the investor attaches to the credit, which depends on the investor's tax circumstances (that is, their marginal tax rate). As these will differ across investors, the value of franking credits may be between nil and full value (i.e. a gamma value between zero and one). A low value of gamma implies that shareholders do not obtain much relief from corporate taxation through imputation and therefore require a higher pre-tax income in order to justify investment.

[181] This is consistent with the inflation assumptions used in developing tariffs throughout this report, except for 2012/13, where State Budget figures were adopted.

[182] P. Monkhouse, 'Adapting the APV Valuation Methodology and the Beta Gearing Formula to the Dividend Imputation Tax System', *Accounting and Finance*, 37, vol. 1, 1997, pp. 69-88.

Payout Ratio (F)

72. The Authority is aware of the recent decision by the Australian Competition Tribunal with regard to the payout ratio. The Authority considers that the range of the payout ratio of 70 per cent to 100 per cent is appropriate given the information currently available to the Authority.

73. The Authority considers that an estimate of the payout ratio of 70 per cent is appropriate based on the empirical evidence currently available. This estimate is consistent with the Tribunal's decision with regard to the value of the payout ratio.[183] The Authority is of the view that existing evidence still supports the use of a range of 70 per cent and 100 per cent for payout ratio. However, for regulatory certainty, the Authority considers that there is no new evidence at this time that would cause the Authority to depart from the findings of the Tribunal in respect of gamma.

74. In conclusion, the Authority's decision is to adopt the payout ratio of 70 per cent in this Draft Report.

Theta (θ)

75. The dividend drop-off study is the only approach used by the Tribunal to determine the value of theta. The Tribunal considered that redemption rate studies should only be used as a check on the reasonableness of the market value of imputation credits as estimated from dividend drop-off studies. On this basis, the Authority may consider further evidence on the estimate of theta using redemption rate studies in the future when this sort of study has been refined on economically justifiable grounds (such as a consideration of any time value loss between when imputation credits are distributed and when they are redeemed, which is currently not taken into account in redemption rate studies).

76. The Authority maintains its position in its previous regulatory decision[184] that dividend drop-off studies are affected by estimation issues, including multicollinearity and heteroscedasticity. As such, estimates of theta using dividend drop-off studies are inherently imprecise. As a result, the Authority is of the view that a range of evidence should be considered where available.

77. For the same reason as discussed in paragraph 73 with regard to the estimate of the payout ratio, the Authority considers that, for regulatory certainty, it should apply a value of theta which is consistent with the Tribunal's decision, for the purpose of this draft decision. As such, the Authority uses SFG's 2011 dividend drop off study, which estimated a value of theta of 0.35, in this Draft Report.[185]

[183] Australian Competition Tribunal, Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9 (24 December 2010), paragraph 4

[184] For example, see Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, 31 October 2011, page 140.

[185] Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011), paragraph 38

Gamma (γ)

78. Based on an estimate of the payout ratio of imputation credits of 70 per cent, together with an estimate of theta of 0.35, the Authority concludes that a reasonable value of gamma, for the purpose of the Authority's draft decision on Western Power's proposed Access Arrangement, is 0.25 (or 25 per cent). The estimate of gamma of 0.25 is consistent with the Tribunal's decision on gamma.[186]

Conclusion

79. The Authority adopts the estimate of gamma of 0.25 to derive the cost of capital for this purpose of this Draft Report.

[186] Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011), paragraph 42

Conclusion on Rate of Return

80. Based upon the above assessments of each of the WACC parameters, the point estimates that the Authority considers may reasonably be applied to parameters of the WACC in estimating the rate of return for Synergy, which will be adopted in the estimate of the retail margin using the return on asset approach, as follows:

81.

Table 44 A Determination of a Rate of Return as at 30 April 2012

Parameter	Value
Nominal Risk Free Rate $\left(R_f\right)$	3.42%
Real Risk Free Rate $\left(R_f^r\right)$	1.05%
Inflation Rate π_e	2.35%
Debt Proportion $\left(D\right)$	40%
Equity Proportion $\left(E\right)$	60%
Australian Market Risk Premium (MRP)	6%
Debt Risk Premium	3.122%
Equity Beta $\left(\beta_e\right)$	0.83
Corporate Tax Rate $\left(T_c\right)$	30%
Franking Credit $\left(\gamma\right)$	25%
Nominal Pre Tax Cost of Equity $\left(R_e^{n,\text{pre-tax}}\right)$	10.84%
Real Pre Tax Cost of Equity $\left(R_e^{r,\text{pre-tax}}\right)$	8.29%
Nominal After Tax Cost of Equity $\left(R_e^{n,\text{post-tax}}\right)$	8.40%
Real After Tax Cost of Equity $\left(R_e^{r,\text{post-tax}}\right)$	5.91%

Source: ERA Analysis

Table 45 Authority's estimates of WACC for Synergy

WACC	Value (Per cent)
Nominal Pre Tax WACC $\left(WACC_n^{\text{pre-tax}}\right)$	9.17%
Real Pre Tax WACC $\left(WACC_r^{\text{pre-tax}}\right)$	6.66%
Nominal After Tax WACC $\left(WACC_n^{\text{post-tax}}\right)$	7.71%
Real After Tax WACC $\left(WACC_r^{\text{post-tax}}\right)$	5.23%

Source: ERA Analysis

Appendix F. Synergy's Concessions and Rebates

The following concessions and rebates are currently available to Synergy customers:

Table 46 Synergy's Customer Concessions 2011/12

Concession	Eligibility	Amount
Supply Charge Rebate	• Seniors Card holder • Centrelink Health Care Card • Pensioner Concession card • Veteran Affairs Gold Card • Commonwealth Seniors Health Card	Equal to fixed daily supply charge 38.23 c/day
Reduced meter testing fees	• Centrelink Health Care Card • Pensioner Concession card • Veteran Affairs Gold Card • Commonwealth Seniors Health Card	
Account establishment fee rebate	• Centrelink Health Care Card • Pensioner Concession card • Veteran Affairs Gold Card • Commonwealth Seniors Health Card	
Energy charge rebate (portion)	Eligible card (above) plus dependent children listed on card	Calculated daily according to number of children. The rebate varies depending on the amount of children, as follows: 1: 61.30 cents/day 2: 77.89 cents/day 3: 94.48 cents/day 4: 111.07 cents/day
Air-conditioning rebate	Reside north of the 26th parallel and/or north of the 50 day Relative Strain Index line, hold a Seniors Card and a • Pensioner Concession card / Commonwealth Seniors Health Card • Veteran Affairs Gold Card with dependent children • Centrelink Health Care Card with dependent children Pensioner concessions card with dependent children	200kWh per month for Dec, Jan, Feb
Fridge replacement scheme	Parts of HUGS scheme. Eligibility determined by accredited financial counsellor	
Life support equipment electricity subsidy	Heart, lung, or kidney disease as certified by doctor	Fixed sum p.a. varies by equipment type
Permanent Caravan Park Resident Air conditioning subsidy	Reside in selected towns, hold a Seniors Card and a • Pensioner Concession card / Commonwealth Seniors Health Card • Veteran Affairs Gold Card with dependent children • Centrelink Health Care Card with dependent children Pensioner concessions card with dependent children	200kWh per month for Dec, Jan, Feb (plus March for Mullewa)
Thermoregulatory dysfunction energy subsidy	Financially disadvantaged and have medical advice that you need temperature control (a/c, heating)	$527 pa paid annually in advance

Appendix G. Glossary

AA3	Western Power's third revised Access Arrangement
ACCC	Australian Competition and Consumer Commission
Act	Economic Regulation Authority Act 2003
AER	Australian Economic Regulator (for the Eastern States)
AMP	Asset Management Plan
Authority	Economic Regulation Authority (Western Australia)
BCI	Building Construction Index
Biomass	Renewable organic materials, such as wood, agricultural crops or wastes, and municipal wastes, especially when used as a source of fuel or energy. Biomass can be burned directly or processed into biofuels such as ethanol and methane.
CAGR	Compound Annual Growth Rate
CAPM	Capital Asset Pricing Model
CARC	Customer Acquisition and Retention Cost
CCGT	Combined Cycle Gas Turbine
CCI	Chamber of Commerce and Industry
COAG	Council of Australian Governments
Cost-reflective Tariffs	Tariffs applying to a certain class of customers that generate revenue that exactly covers the cost of supplying electricity to that class of customers.
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CSO	Community Services Obligation
Distribution	Distribution generally relates to the electricity network that extends from the zone sub-station to the customer's premises.
DSM	Demand Side Management
DTF	Department of Treasury and Finance
DWAT	Discounted Weighted Average Tariff
ERA	Economic Regulation Authority (Western Australia)
ERACCC	Economic Regulation Authority Consumer Consultative Committee
ERMR	Office of Energy Electricity Retail Market Review
esaa	Energy Supply Association of Australia
FRC	Full Retail Contestability
GFC	Global Financial Crisis
Gifted Assets	Those assets owned by the service provider but which were funded through an external source, such as developer contribution or government funding.
GST	Goods and Services Tax
GTE	Government Trading Enterprise

GW	Gigawatt, 1 billion watts or 1000 megawatts
GWh	Gigawatt hour
HEP	Hardship Efficiency Program
HUGS	Hardship Utility Grant Scheme
IMO	Independent Market Operator
IPART	Independent Pricing and Regulatory Tribunal (in New South Wales)
IRCR	Individual Reserve Capacity Requirement
kW	Kilowatts, 1000 watts
kWh	Kilowatt hour
LDC	Load Duration Curve
LGC	Large Generation Certificate
LRET	Large Scale Renewable Target
LRMC	Long Run Marginal Cost, being the change in the long-run total cost of producing a good or service resulting from a change in the quantity of output produced. There are no fixed inputs in the long run. As such, there is only variable cost. This means that long-run marginal cost is the result of changes in the cost of all inputs.
MJA	Marsden Jacob Associates
MRCP	Maximum Reserve Capacity Price
MRET	Mandatory Renewable Energy Target
MRP	Market Risk Premium
MW	Megawatts, 1 million watts or 1000 kilowatts
MWh	Megawatt hour
Network charges	The fees charged by a network operator and paid by generators and retailers for use of the network operator's network to transport electricity.
NWIS	North West Interconnected System – the system of generation, network and distribution centring around Karratha and Port Hedland in the far north west of Western Australia.
OCGT	Open Cycle Gas Turbine
OoE	Office of Energy
ORER	Office of the Renewable Energy Regulator
PASA	Projected assessment of system adequacy
PV	Photovoltaic
QCA	Queensland Competition Authority
RBA	Reserve Bank of Australia
REBS	Renewable Energy Buyback Scheme
REC	Renewable Energy Certificate
Renewable energy	Energy that is generated from renewable sources such as wind, solar or water (hydro).
RET	Renewable Energy Target
Revenue requirement	A level of revenue, to be collected from regulated tariffs, covering the efficient costs of providing a utility service to a required performance standard.

RPP	Renewable Power Percentage
SBF	State Budget Forecast
SME	Small and Medium Enterprise
[redacted]	Synergy's short run optimised procurement model
SRES	Small-Scale Renewable Energy Scheme
STEP	Synergy's Short Term Electricity Projection model
STARS	Synergy's day-ahead forecasting model
STC	Small-Scale Technology Certificate
STEM	Short Term Energy market
STP	Small-Scale Technology Percentage
SWIS	South West Interconnected System – the system of generation, networks and distribution supplying the area between Kalbarri in the north and Albany in the south and stretching out to Kalgoorlie in the east.
Synergy	The state-owned Electricity Retail Corporation, operating in the SWIS.
Transmission	Transmission generally relates to the electricity network from the generating power station to zone sub-stations, which are located at key points around the supply area.
TEC	Tariff Equalisation Contribution − paid by Western Power's customers through their network charges, to Horizon Power to fund the shortfall between the uniform tariff revenue and the cost of supplying electricity to customers.
TEF	Tariff Equalisation Fund
Uniform Tariff	A state government policy which ensures all small use customers pay the same tariffs regardless of where they live in Western Australia.
Verve	Verve Energy − the state-owned Electricity Generation Corporation, operating in the SWIS.
WACC	Weighted Average Cost of Capital - is the minimum return that a company must earn on existing asset base to satisfy its creditors, owners, and other providers of capital, or they will invest elsewhere. It is generally calculated as the proportion of debt and equity funding used by the company compared to market risk free rates.
WACOSS	Western Australian Council of Social Service
Watt	The SI (International System of Units) unit of power, equivalent to one joule per second and equal to the power in a circuit in which a current of one ampere flows across a potential difference of one volt.
WEM	Wholesale Electricity Market – for the trading of electricity between generators and retailers in the SWIS.
Western Power	The state-owned Electricity Networks Corporation, operating in the SWIS.
[redacted]	Synergy's long-run optimised procurement model