Inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs

Draft Report

Submission by Alan Hughes

Comments are added to the original document

"All energy costs and sales should be in $/GJ
to allow comparison between electricity & gas"

"Power (in Watts) should be used for rates of energy consumption, because generators and appliances are all rated in Watts. Watts remain the same regardless of duration unless the consumption changes"

4 April 2012

Economic Regulation Authority

WESTERN AUSTRALIA

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Introduction

The Economic Regulation Authority (Authority) is conducting 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.

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 has asked the Authority to calculate efficient cost reflective electricity tariffs for Synergy for the four years from 2012/13 to 2015/16.

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

This report presents the draft findings and recommendations of the Authority and calls for public submissions (by 2 May 2012). It follows public consultation on an issues paper, which was published on 11 August 2011 and incorporates analysis by consultants who were employed by the Authority to provide technical advice, as well as analysis undertaken by the Authority. A final report is due to be provided to the Treasurer by 1 June 2012.

Background

Residential electricity prices in Western Australia have increased by 57 per cent in recent years. The increases in residential retail tariffs from April 2009 followed 12 years of constant electricity tariffs (meaning that tariffs had not even kept pace with inflation since 1997/98). The tariff increases were largely the result of:

[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 distribution 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 to electricity retailers 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?

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, it is important to note that electricity costs are made up of the following components:

- 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 profit that the electricity retailer must earn to have an incentive to provide a service (around 3 per cent of total costs).

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 fully competitive and efficient. This is clearly not the case at present in Western Australia; Synergy, the dominant retailer, accounts for more than 70 per cent of the retail market in 2010/11 (large electricity users can choose their retailer), while Verve Energy accounts for more than 50 per cent of generation capacity.

[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).

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 (for example, as 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.

While 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 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 the same 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 the distribution network charges under Tariff Equalisation Contribution (TEC) scheme.[3]

In calculating the efficient cost reflective level of tariffs, the Authority considers that the TEC should not be part of the efficient cost for electricity tariffs and recommends that the TEC no longer be met by electricity consumers in the South West. The subsidy to Horizon Power is not a cost that is associated with generating, distributing or retailing electricity in the South West. It is a cost associated with 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 $95 (or 6 per cent) of a residential consumer's annual electricity bill in 2011/12.

Accordingly, the analysis and the results provided in this report are exclusive of the TEC, unless otherwise stated, as the TEC is not a component of an efficient, cost reflective tariff.

The terms of reference requires that the Authority determine cost reflective retail tariffs. In doing so, the Authority has examined Synergy's non-tariff or market-based customers to ensure appropriate cost allocations for the components of each tariff. However, the Authority does not present any data or findings on non-tariff customers in this report.

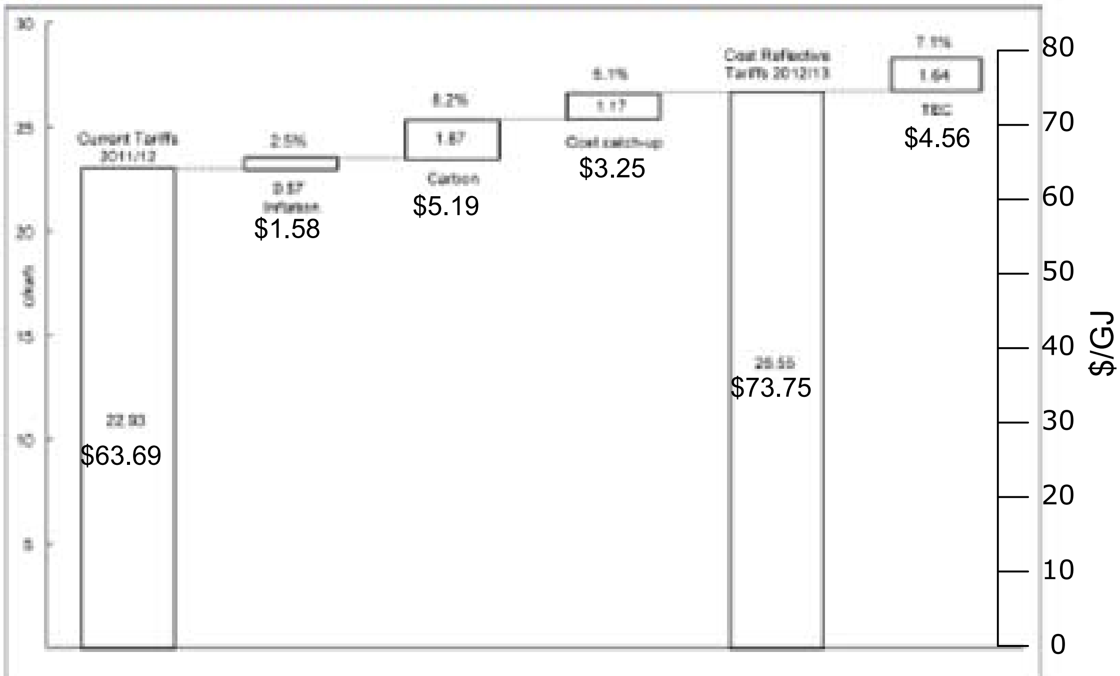
Draft Findings

The Authority has estimated that Synergy's overall revenue from regulated customers, on average, must increase by approximately 16 per cent to achieve efficient cost reflectivity, after allowing for the additional cost associated with the carbon pricing regime to take effect on July 1 this year.

[3] TEC is explained in more detail in section 5.1.1 of this Report.

Figure 1 illustrates the movement from current tariffs to cost reflective tariffs, averaged across all regulated customer categories .

Figure 1 Gap Between Current Tariffs and Cost Reflective Tariffs in 2012/13



Source – ERA Analysis

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

The largest proportion of the increase required is to meet the cost of the new carbon pricing regime that has been introduced by the Federal Government. This is estimated at 1.87 c/kwh (or 8.2 per cent).

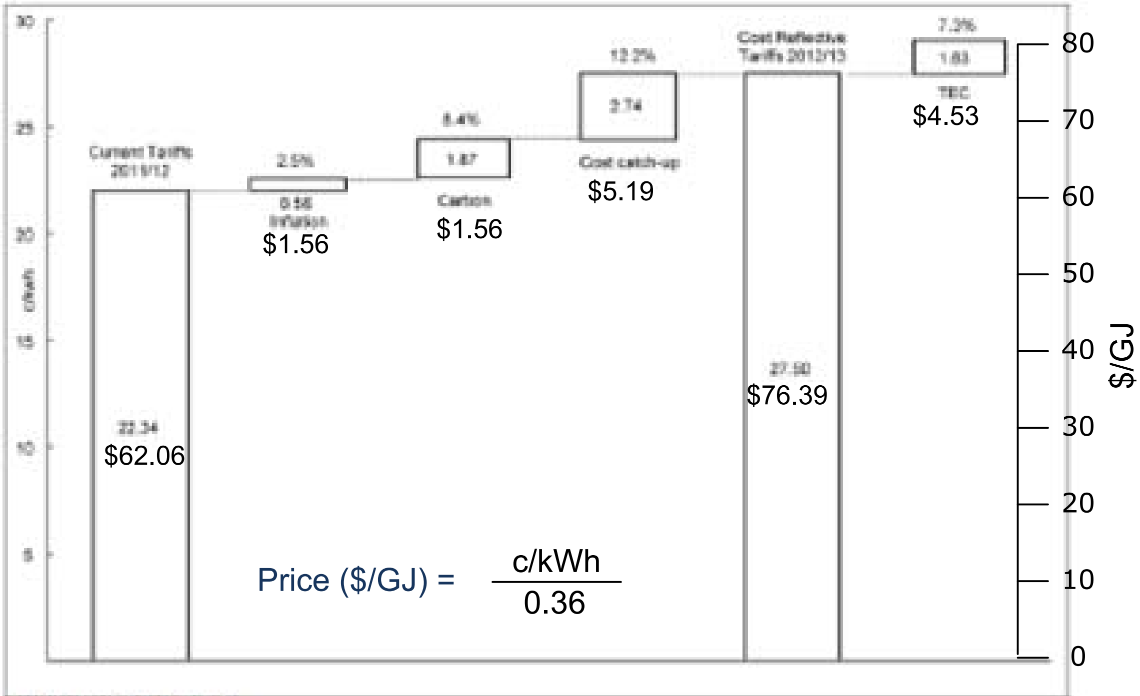
To bring the tariffs to cost reflectivity in 2012/13, a further increase of 1.17 c/kwh (or 5.1 per cent) will be needed to catch-up on other cost increases faced by Synergy.

If the TEC continues to be retained, the gap between current tariffs and cost reflective tariff is even greater, adding another 1.64 c/kwh (or 7.1 per cent) to the average tariff.

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 23.1 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



Source – ERA Analysis

Currently, residential customers pay on average 22.34 c/kwh. In 2012/13, an adjustment for inflation would increase this average price by 0.58 c/kwh (or 2.5 per cent).

The impact of the new carbon pricing regime will add a further 1.87 c/kwh (or 8.4 per cent).

Residential tariffs would need to increase by a further 2.74 c/kwh (or 12.2 per cent) to reflect other cost pressure in order to bring the tariffs to cost reflectivity in 2012/13.

If the TEC continues to be retained, it will add a further 1.63 c/kwh (or 7.3 per cent) to the average residential tariff.

The Authority is aware that the Government will announce electricity tariffs for 2012/13 as part of the budget papers. As this information is not available at this time, the Authority has assumed that tariffs will increase by the amount that was provided for in the 2011/12 Budget papers, which specifies an increase in Synergy's tariff of 5 per cent 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.[4,5]

If both the tariff increase and full carbon pass through as indicated in the Government's previous budget papers (i.e. 5 per cent plus 8.4 per cent estimated carbon pass through) were to occur in 2012/13, the average tariff for residential customers will be 25.33 c/kwh. The gap between the efficient cost reflective tariff and the average tariff for residential customers would be 2.2 c/kwh (or 8.6 per cent) in 2012/13.

Domestic power consumption averaged over a whole year is approximately 1 kW

Electrical energy used over a year is approximately = 31.56 GJ

However, the Authority has estimated that for the following three years (i.e. until 2015/16) the cost reflective level of tariffs will remain relatively constant with average residential tariffs in 2015/16 rising to 28.08 c/kwh. The Authority's estimate is that cost reflectivity $78.00/GJ could be achieved by having residential tariffs increase by 3.5 per cent per annum for the remaining years from 2013/14 to 2015/16. A large proportion of this increase is inflation, assumed to be at 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 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 calculated. 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 Long Run Marginal Cost.

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 (55 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 those contracts efficiently. The contracts that Synergy currently has include those that were competitively procured, and a bilateral contract 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.

The second type consists of a single contract between Verve Energy and Synergy, called the vesting contract, which is a contract that was set by the Government.[6] The vesting contract was first introduced in April 2006, and was subsequently replaced in 2010. This replacement vesting 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 replacement vesting contract was not open and competitive. The Authority cannot confirm whether the replacement vesting contract has delivered an efficient outcome to Synergy.

Long Run Marginal Cost

The LRMC approach attempts to estimate the efficient wholesale electricity costs associated with meeting the energy consumption patterns of different customer groups.

The LRMC calculation sets a benchmark for an existing retailer with regard to the efficiently incurred wholesale electricity costs. It is intended to provide sufficient revenue for a new retailer to enter the market and procure electricity.

The rationale in establishing LRMC as the efficient cost of wholesale electricity is that, in the long run, the cost of capacity and energy combined is expected to gravitate towards the LRMC in a well functioning market. LRMC has been used by most other regulators in Australia to either set cost reflective tariffs or to set a range of cost reflective tariffs.

The Authority has included the capacity costs specific to the Western Australian market in the LRMC estimate to reflect the additional costs associated with the capacity requirements set by the Independent Market Operator (IMO).

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 carbon-inclusive estimates under both approaches are similar in 2012/13, with LRMC being 0.5 per cent below the estimate based on Synergy's existing contracts. However, the difference increases from 2013/14 onwards.

The difference is largely attributable to the allowed cost pass-through for carbon. Synergy's actual cost of electricity is estimated based on contracts with existing, 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 when the carbon price is introduced, if cost full pass through is allowed. This, however, will provide no incentive for the retailer to work with its electricity suppliers to find innovative ways for reducing carbon intensity.

The LRMC is calculated on the assumption that generators are able to respond immediately to the carbon price, and reduce their carbon intensity and the carbon cost pass through to the same level as a new, less carbon intensive generator.

However, the Authority recognises that generators may not be able to respond immediately to the carbon price. Therefore, the Authority considers it appropriate to delay the adoption of the lower LRMC cost for two years. The Authority has accepted the

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

estimated costs for Synergy based on its existing contracts in the first two years; being 2012/13 and 2013/14, and recommends the adoption of the LRMC cost approach for the following two years; 2014/15 and 2015/16.

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 $7 million in 2010/11. 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.

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 $81.50 per small regulated customer for 2012/13.

As with the wholesale electricity cost, the Authority recognises that a move towards this efficient level of operating cost will require a period of transition. As such, the Authority has accepted the operating cost per small regulated customer for 2012/13 and 2013/14 and recommends the lower level of $85.60 and $87.77 for the following two years (being $81.50 adjusted for inflation).

The Authority also recommends a similar retail operating cost transition for large customers, but has not published details of calculations in its report for confidentiality reasons.

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

[7] Data provided by Synergy.

indicates that, following a period of significant network cost increases, there is likely a reduction in network tariffs in real terms over the next five years.[8]

As a registered market customer in the Wholesale Electricity Market, 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 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).

What happens to electricity supplied by the customer to the grid?

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.

Because the retail margin is intended to address the risks of running a business, the Authority considers it most appropriate to apply a single retail margin to all of Synergy's operations (as would be done by an electricity retailer operating in a competitive market), rather than treating its contestable and non-contestable operations as separate businesses. Hence, the Authority does not consider it appropriate to adopt separate retail margins for contestable and non-contestable customers. Additionally, the practice of adopting multiple retail margins is largely inconsistent with regulatory decisions in other jurisdictions.

The equivalent of a retail margin in the case of an electricity network business is the rate of return, or the Weighted Average Cost of Capital (WACC). A return on assets is determined as a product of the WACC 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 of 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 estimate 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.

[8] This can be accessed from the ERA's website

The Authority estimates that an appropriate rate of return for Synergy is 7.4 per cent, on a pre-tax, nominal basis.

Based on these assessments, the Authority's draft finding is that an appropriate retail margin for Synergy for the inquiry period is 3.5 per cent of Synergy's total cost. The dollar value of the retail margin for Synergy is in the range of $69 million to $73 million per year (nominal).

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 cost of service (c/kWh) for each customer category. The average annual revenue requirement for each customer category is identified in Table 1 below. See the next few pages

Table 1 Synergy's average efficient costs per cost component (c/kWh)

Tariff	Tariff Description	2011/12 Actual	2012/13 Cost Reflective	2013/14 Cost Reflective	2014/15 Cost Reflective	2015/16 Cost Reflective
	Non-contestable					
A1	Residential	22.34	27.50	27.62	26.81	28.08
B1	Residential water heating	14.25	18.22	18.75	19.05	19.77
C1	Non-profit organisations	22.26	24.40	24.52	23.73	24.80
D1	Charitable residential	18.79	23.74	24.01	23.13	24.80
K1	Mixed commercial & residential	23.75	26.65	26.78	26.27	27.37
L1	Low voltage supply (<50 MWh)	24.02	27.01	27.10	26.49	27.63
R1	Time-of-use tariff (<50 MWh)	17.37	25.12	25.26	24.50	25.65
W1	Traffic lights	22.91	24.49	24.61	22.77	24.04
Z1	Street lights	36.50	35.90	38.47	39.05	40.26
UMS	Unmetered supply	22.91	23.57	23.68	21.99	23.22
	Contestable					
L3	Low voltage supply (>50 MWh)	29.04	26.44	27.45	29.80	35.04
M1	General supply (high voltage)	25.21	25.60	26.71	26.00	26.88
R3	Time-of-use tariff (>50 MWh)	23.25	21.09	21.16	20.67	21.70
S1	Low/med voltage time-of-use	19.33	21.13	21.11	20.11	21.09
T1	High voltage time-of-use	18.56	19.82	19.84	18.94	19.87
	Average across all tariffs	**22.93**	**26.55**	**26.71**	**26.00**	**27.26**

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 revenue amount of 22.93 c/kwh to an average revenue of 27.26 c/kwh in 2015/16. $63.69/GJ

$75.72 /GJ

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 period. Ultimately, this is a decision for the Government since it is outside the scope of the Authority's function to set tariffs for Synergy. However, for illustrative purposes, the Authority has undertaken the bill impact analysis for residential customers, on a smoothed basis (that is, equal increase each year, after the initial increase in 2012/13 that has been assumed for the Government's current budget). On this basis, the bill impact for

Synergy's average efficient costs per cost component ($/GJ)

Tariff	A1	B1	K1	C1	D1	L1	L3
2011 Actual	$ 62.06	$ 39.58	$ 65.97	$ 61.83	$ 52.19	$ 66.72	$ 80.67
2012	$ 76.39	$ 50.61	$ 74.03	$ 67.78	$ 65.94	$ 75.03	$ 73.44
2013	$ 76.72	$ 52.08	$ 74.39	$ 68.11	$ 66.69	$ 75.28	$ 76.25
2014	$ 74.47	$ 52.92	$ 72.97	$ 65.92	$ 64.25	$ 73.58	$ 82.78
2015	$ 78.00	$ 54.92	$ 76.03	$ 68.89	$ 68.89	$ 76.75	$ 97.33

Synergy's average efficient costs per cost component ($/GJ)

Tariff	M1	R1	R3	S1	T1
2011 Actual	$ 70.03	$ 48.25	$ 64.58	$ 53.69	$ 51.56
2012	$ 71.11	$ 69.78	$ 58.58	$ 58.69	$ 55.06
2013	$ 74.19	$ 70.17	$ 58.78	$ 58.64	$ 55.11
2014	$ 72.22	$ 68.06	$ 57.42	$ 55.86	$ 52.61
2015	$ 74.67	$ 71.25	$ 60.28	$ 58.58	$ 55.19

Synergy's average efficient costs per cost component ($/GJ)

Tariff	W1	Z1	UMS	Aver-age		CO_2 Price $/GJ	$ / tonne
2011 Actual	$ 63.64	$ 101.39	$ 63.64	$ 63.69			
2012	$ 68.03	$ 99.72	$ 65.47	$ 73.75		$ 5.93	$ 23.00
2013	$ 68.36	$ 106.86	$ 65.78	$ 74.19		$ 6.23	$ 24.15
2014	$ 63.25	$ 108.47	$ 61.08	$ 72.22		$ 6.55	$ 25.40
2015	$ 66.78	$ 111.83	$ 64.50	$ 75.72		?	?

Synergy Prices Compared 2011/2012			
Tariff	**Tariff Name**	**Supply charge $ / year**	**Energy Charge $ / GJ**
A1	**Home Plan**	$ 146.61	$ 60.75
	Average power consumption 708 W = (708 x .0316 x $60.75) + $146.61 = $1,504.30	$ 146.61	$ 1,357.69
	708 x .0316 = 22.35 GJ 22.35 x .258 = 5.77 tonnes pa 5.77 x $23 = $133 for Carbon dioxide pa		
B1	**Hot Water plan**	$ 75.97	$ 31.92
Smart Power	**Smart Power**	$ 146.61	
	Peak 20.8 % of a year		$ 117.08
	Shoulder 20.8 % of a year		$ 59.56
	Weekend 16.7 % of a year		$ 49.36
	Off-Peak 41.7 %		$ 31.44
	Constant fixed power consumption		$58.10
K1	**Home Business plan**	$ 146.61	
	<833 W		$ 60.75
	0.833 - 68.75 kW		$ 59.47
	>68.75 kW		$ 68.75
C1	**Community service**	$ 133.90	
	<833 W		$ 55.50
	0.833 - 68.75 kW		$ 69.56
	>68.75 kW		$ 62.75
D1	**Charity Accommodation**	$ 133.90	$ 55.50

Synergy Prices Compared 2011/2012

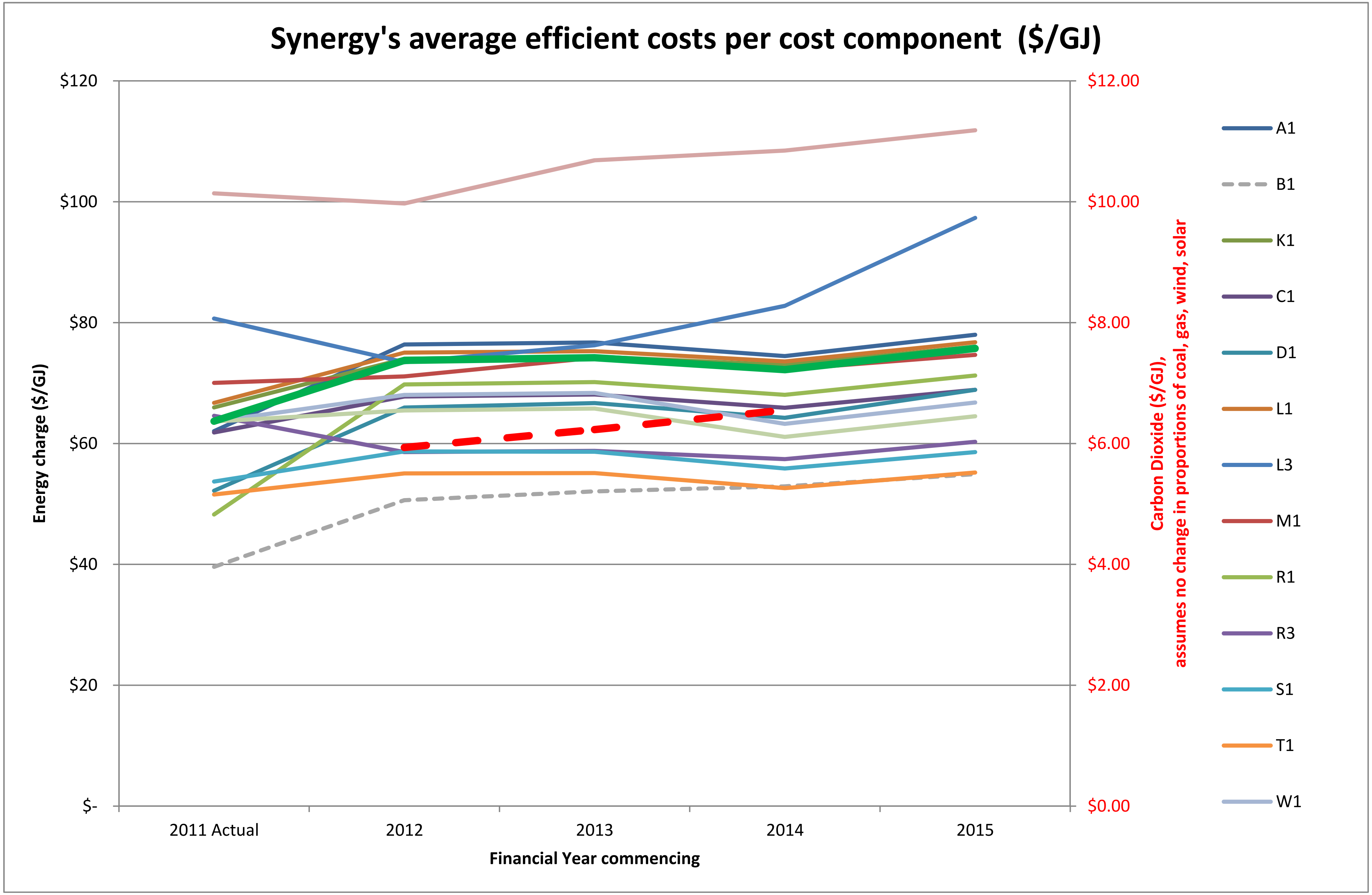
Tariff	Tariff Name	Supply charge $ / year	Energy Charge $ / GJ
L1	**Business Plan <5.7 kW** (230/400 V)	$ 139.12	
	<68.75 kW		$ 69.56
	Maximum charge 5.77 kW =5.77 x 31.56 = 182 GJ (182 x $69.56) + $139.12 = $12,659 pa	$ 139.12	$12,520
	5.77 x 31.56 = 182 GJ 182 x .258 = 46.94 tonnes pa 46.94 x $23 = $1080 for Carbon dioxide pa		
	~~>68.75 kW~~		~~$ 62.75~~
L3	**Business Plan >5.7 kW** (230/400 V)	$ 180.14	
	<68.75 kW		$ 90.00
	68.75 kW = 2170 GJ = $195,438 pa	$ 180.14	$ 195,258
	560 t = $12,874 pa CO_2		
	>68.75 kW		$ 81.25
M1	**Large Business Plan** (6.6 - 33 kV)	$ 166.04	
	<68.75 kW		$ 80.17
	68.75 kW = 2170 GJ = $174,090 pa	$ 166.04	$ 173,924
	560 t = $12874 pa CO_2		
			$ 72.00
R1		$ 569.78	
	Peak M-F 08:00 - 21:59:59 = 41.6667 %		$ 76.14
	Off Peak 58.3333 %		$ 23.47
	5.704 kW continuous = $8,745 pa 180 t = $4,140 CO_2	$ 569.78	$ 8,175

Synergy Prices Compared 2011/2012			
Tariff	**Tariff Name**	**Supply charge $ / year**	**Energy Charge $ / GJ**
R3	**Business Plan Time of use Fifty** >5.704 kW	$ 180.14	
	5.704 kW continuous = $11354 pa	$ 180.14	$ 11,174
	Peak M-F 08:00 - 21:59:59 = 41.6667 %		$ 104.11
	Off Peak 58.3333 %		$ 32.06
S1	**Large Business Plan Demand LV** 230/400 V Power Factor 0.8 - 1.0		
	Minimum charge **= a constant 145 kW**	$ 146,356	
	4.576 TJ = 1181 t = $27,152 pa		
	Peak M-F 08:00 - 21:59:59 = 41.6667 %		$ 40.44
	Off Peak 58.3333 %		$ 25.58
	Demand charge The power consumption is calculated in 30 minute blocks. The highest one in the 24 hours is used for calculation. The peaks on off peak times are reduced to 30 % of their power	$1.0178 x kW_{max} Calculated daily cumulative	$ 565.44
T1	6.6 - 33 kV Power Factor 0.8 - 1.0	$ -	
	Minimum charge **=a constant 142 kW**	$ 207,712.45	
	Peak M-F 08:00 - 21:59:59 = 41.6667 %		$ 40.69
	Off Peak 58.3333 %		$ 27.06
	Demand charge The power consumption is calculated in 30 minute blocks. The highest one in the 24 hours is used for calculation. The peaks on off peak times are reduced to 30 % of their power	$1.0019 x kW_{max} Calculated daily cumulative	$ 556.61

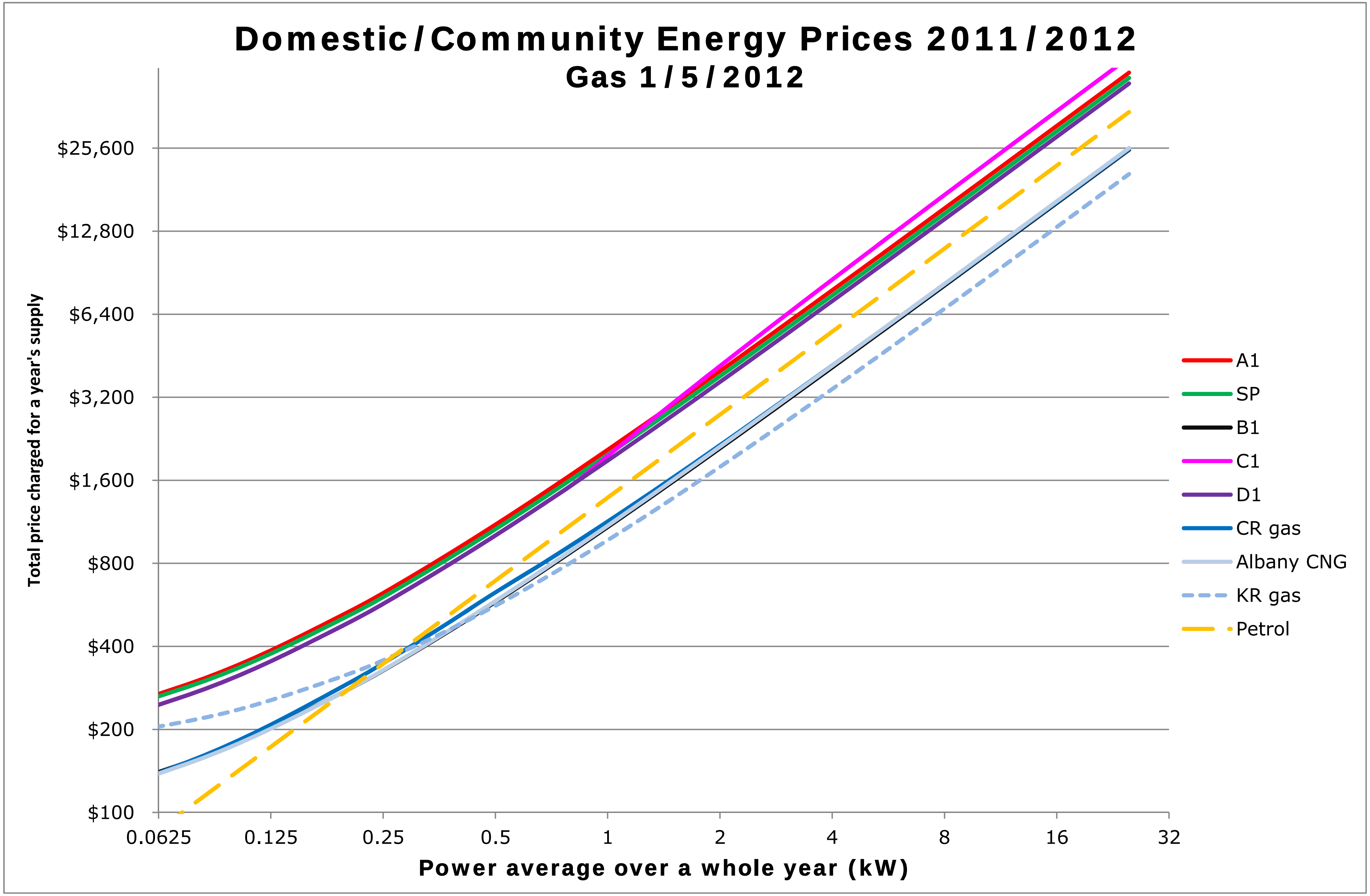
Synergy Prices Compared 2011/2012			
Tariff	**Tariff Name**	**Supply charge $ / year**	**Energy Charge $ / GJ**
CR	**Alinta Energy Coastal Residential 1 / 5 / 2012**		
	Supply charge	$ 67.72	
	Piped natural gas power <0.5 kW		$ 35.53
	Average power consumption 500 W = (500 x .0316 x $35.53) + $67.72 = $628.24	$ -	$ -
	500 x .0316 = 15.78 GJ 15.78 x .0599 = 0.945 tonnes pa 5.77 x $23 = $21.74 for Carbon dioxide pa		
	Piped natural gas power >0.5 kW		$ 32.06

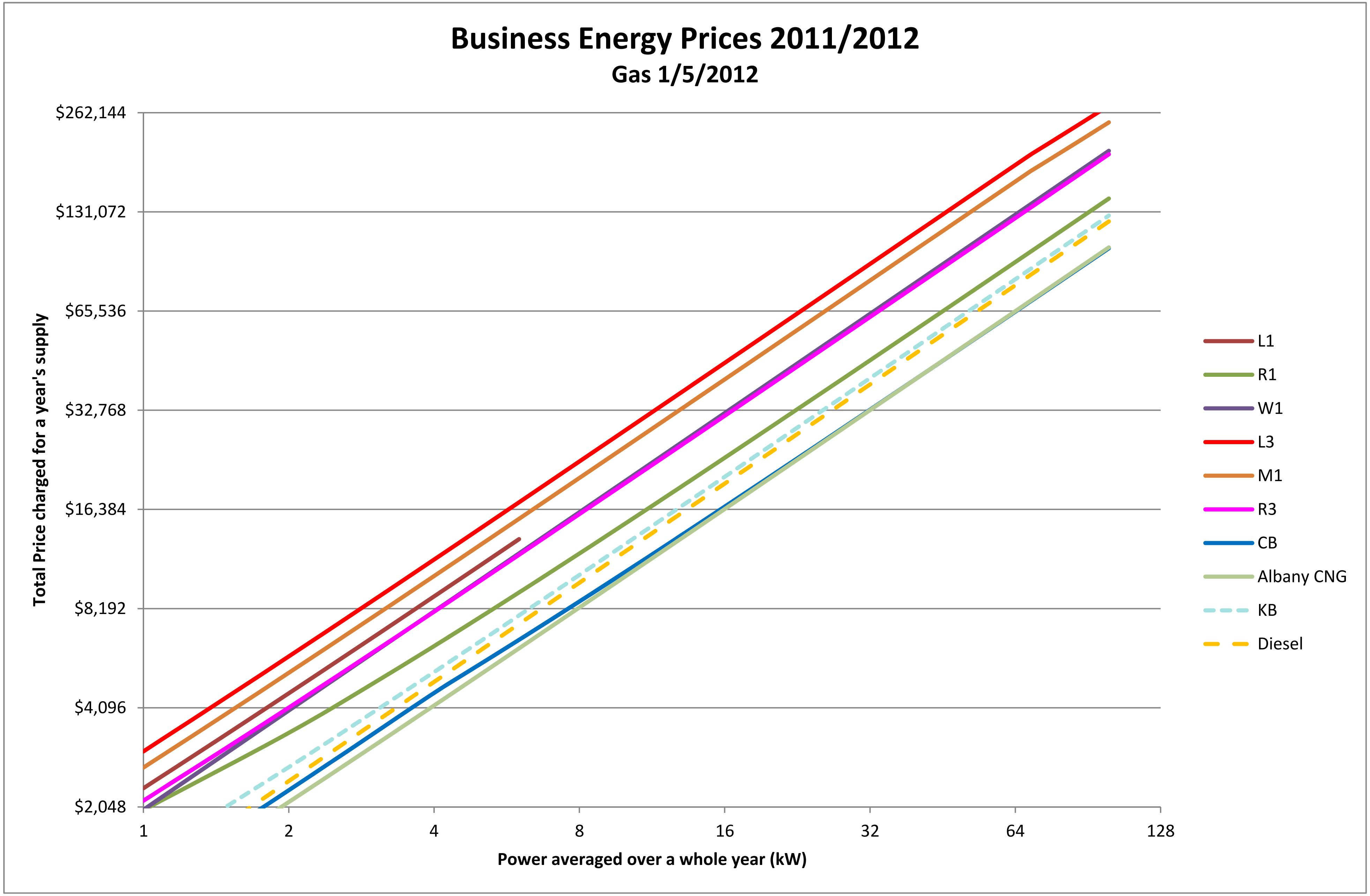
Synergy Prices Compared 2011/2012			
Tariff	**Tariff Name**	**Supply charge $ / year**	**Energy Charge $ / GJ**
CB	**Alinta Energy Coastal Business 1 / 5 / 2012**		
	Supply charge	$ 58.91	
	Piped natural gas power <4.167 kW		$ 35.53
	4.167 kW =4.167 x 31.56 = 131 GJ (131 x $35.53) + $58.91 = $4730.34 pa		
	4.167 x 31.56 = 131 GJ 131 x .0599 = 7.88 tonnes pa 7.88 x $23 = $181.15 for Carbon dioxide pa		
	Piped natural gas power >4.167 kW		$ 32.06
A	**Alinta Energy Albany All customers 1 / 5 / 2012**		
	Supply charge	$ 73.12	
	Bottled gas charge		$ 32.39
KR	**Kalgoorlie Residential 1 / 5 / 2012**		
	Supply charge	$ 152.23	
	Piped gas charge		$ 25.94
KB	**Kalgoorlie Business 1 / 5 / 2012**		
	Supply charge	$ 151.54	
	Piped gas charge		$ 40.44

Synergy Prices Compared 2011/2012			
Tariff	**Tariff Name**	**Supply charge $ / year**	**Energy Charge $ / GJ**
Liquid fuel	**Any Petrol Perth**		
	(150 c/l)		$43.86
	1 l = .039 GJ = 6 cents if taxed		
	29.24 l = 0.0667 t CO_2 = $1.53 if taxed		$43.86
	Diesel Perth		
	(150 c/l)		$38.86
	1 l = .0386 GJ = 6.1 cents if taxed		
	29.24 l = 0.0692 t CO2 = $1.59 if taxed		$34.86
	Biodiesel		
	(150 c/l)		$43.35
	CO_2 absorbed = CO_2 emitted = no tax		


Synergy's average efficient costs per cost component ($/GJ)
Energy charge ($/GJ)
$120
$100
$80
$60
$40
$20
$-
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
Carbon Dioxide ($/GJ),
assumes no change in proportions of coal, gas, wind, solar
2011 Actual
2012
2013
2014
2015
Financial Year commencing
A1
B1
K1
C1
D1
L1
L3
M1
R1
R3
S1
T1
W1

Notice: The similarity of shape of all but petrol, with the fixed charges flattening the increase in price with respect to consumption. The supply charge is much lower for gas than for Synergy.




Business Energy Prices 2011/2012
Gas 1/5/2012
Total Price charged for a year's supply
$262,144
$131,072
$65,536
$32,768
$16,384
$8,192
$4,096
$2,048
1
2
4
8
16
32
64
128
Power averaged over a whole year (kW)
L1
R1
W1
L3
M1
R3
CB
Albany CNG
KB
Diesel

residential customers will be $204 in 2012/13, followed by an increase of $63 per year. On average, $36 of this increase relates to inflation.

Impact on Synergy and Government

The Authority's recommendations have no impact on Synergy's tariff revenues during 2012/13 and 2013/14, due to the Authority accepting Synergy's actual forecast costs for the first two years. From 2014/15 onwards the Authority's estimate of Synergy's efficient wholesale electricity costs will see Synergy collect $121 million less than the estimates of its actual forecast costs. The difference between Synergy's projected costs and the Authority's recommended revenue is $121 million in 2015/16 (excluding TEC).

The major contributor to this shortfall is the amount of the carbon cost Synergy is allowed to pass through to its customers. Synergy can reduce its carbon costs if it is able to renegotiate with its contracted generators.

The expected tariff increases in 2012/13 and the Authority's recommended cost reductions have the impact of lessening the financial loss to Government from Synergy's regulated business.

Currently, the Government compensates Synergy for the difference between cost reflective tariffs and actual revenue earned by Synergy. This payment is called the Tariff Adjustment Payment.[9] If Synergy were to charge cost reflective tariffs, the Tariff Adjustment Payment would be zero. In 2011/12, the Tariff Adjustment Payment from the Government to Synergy was $349.6 million[10].

The Tariff Adjustment Payment would be reduced significantly should TEC be removed. The TEC for 2011/12 was set at $181.2 million, of which approximately $129 million can be attributed to Synergy tariff customers.[11]

The table below shows the net impact on government of moving to cost reflective tariffs in combination with the TEC being funded via a CSO. In 2014/15, there is no Tariff Adjustment Payment and the CSO payment by the Government is entirely related to the TEC. The $201.5 million cost to Government in 2015/16 will be offset to some extent by dividends of $54.2 million and tax equivalent payments of $30.9 million.

Table 2 Impact on Government ($m, nominal)

	2011/12	2012/13	2013/14	2014/15	2015/16
Tariff Adjustment Payment	-349.63	-59.55	-39.58	51.05	-
CSO income due to removal of TEC		-186.6	-190.80	-195.70	-201.50
Total Government Impact	**-349.63**	**-246.15**	**-230.38**	**-144.65**	**-201.50**

Source: ERA Analysis

[9] The CSO paid by the Government to Synergy to compensate it for retail tariffs being lower than Synergy's costs.

[10] 2011/12 Budget Paper No. 3, p293.

[11] The TEC also applies to Synergy's market-based (or non-tariff) customers, which the Authority assumes to be operating at cost-reflective levels, and non-Synergy network users. The shortfall between the data in Table 4 and the forecast annual TEC amount is currently funded by these customers.

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[12] of the contestable market in the South West Interconnected System. However, the Authority does not consider the tariffs to be a barrier to competition, as the tariffs for contestable customers are already at or above cost reflective levels. Therefore, the Authority recommends that the contestable market be given a chance to evolve over the next few years, and the effectiveness of the market be assessed in a future review of regulated prices by the Authority.

The Federal Government plans to introduce 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.

Invitation for Public Submissions

The Authority invites interested parties to consider the findings and analysis in the draft report and to make a submission to the Authority. Submissions are due by Monday 2 May 2012. After considering submissions, the Authority will provide a Final Report to the Treasurer by 1 June 2012. The Treasurer will then have 28 days to table the report in Parliament.

12 Synergy (2011), Annual Report, p1.

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 to the Authority inquiries on matters relating to regulated industries.[13]

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[14] 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 has 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.

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

[14] 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 2008/09, the Office of Energy (OoE, now the Public Utilities Office) conducted a review of the Western Australian retail electricity market and published its findings in January 2009. The OOE report noted that, at the 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.[15]

The OOE report also considered that the move toward cost reflective retail tariffs was essential to develop a competitive electricity retail market in the State. The report commented:

> 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.[16]

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 tariff increases for residential and selected commercial tariffs from 2009, as well as budgeted forecasts to 2014/15, are shown in Table 3 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

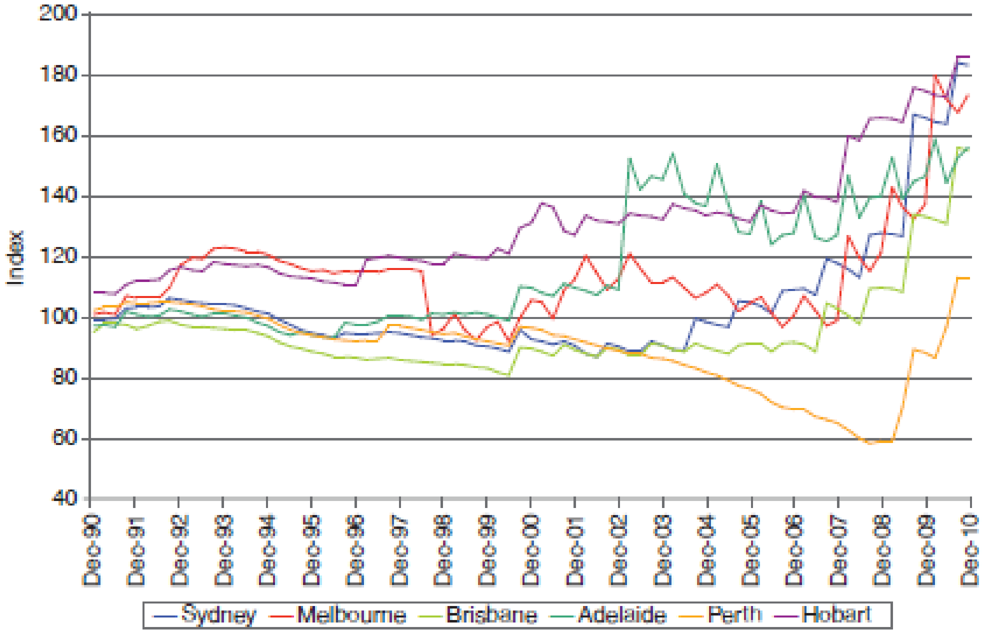
Prior to the tariff increases in 2009, electricity prices in Western Australia had fallen in real terms since 1990. Figure 3 shows the movement in real residential electricity prices in Perth (that is, adjusted for inflation) in contrast to those in other capital cities over the period from 1991 to 2010.

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

[16] Ibid.

Does this graph include inflation?

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



Where is the accompanying graph of the level of subsidies?

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

Privatisation Vic 1994, SA 1999, Qld 2007, NSW ?

This inquiry will determine 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 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 of this inquiry will be 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[17].
- The Authority has consulted with its Consumer Consultative Committee (ERACCC), and will be consulting further with the ERACCC over the course of the inquiry.
- Following consideration of submissions, the Authority has developed a draft set of recommendations, presented in this draft report. Public submissions on the draft report are invited by Monday 2 May 2012 (see section 1.4 below on how to make a submission).

[17] www.erawa.com.au

- The final report for the inquiry is to be delivered to the Treasurer by 1 June 2012 and the Treasurer will, in accordance with the Act, have 28 days to table the report in Parliament.

In accordance with section 45 of the Act, the Authority will act through the Chairman and members in conducting this inquiry.

1.4 How to Make a Submission

Submissions on any matters raised in this draft report should be provided in both written and electronic form (where possible) and addressed to:

Inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs
Economic Regulation Authority
PO Box 8469
Perth Business Centre
PERTH WA 6849

Email: publicsubmissions@erawa.com.au
Fax: (08) 6557 7999

Submissions must be received by 4:00 pm (WST) on Monday 2 May 2012.

Submissions made to the Authority will be treated as in the public domain and placed on the Authority's website unless confidentiality is claimed. The submission, or parts of the submission in relation to which confidentiality is claimed, should be clearly marked. Any claim of confidentiality will be dealt with in the same way as is provided for in section 55 of the Act.

The receipt and publication of a submission shall not be taken as indicating that the Authority has knowledge, either actual or constructive, of the contents of a particular submission. No duty of confidence will arise for the Authority where the submission, in whole or part, contains information of a confidential nature.

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, Synergy's operations and tariffs, is provided as background in Appendix B.

2.2 Current Process for Setting Tariffs

The approach to calculating cost reflective tariffs used in the Office of Energy's 2007/08 Electricity Retail Market Review released in 2007/08 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. GJ

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 Proposed Approach to Determination of Cost Reflective Electricity Retail Tariffs

Estimate Synergy's efficient costs of service provision (= revenue requirement)

- Wholesale energy and capacity purchases
  - Contract efficiency
  - Demand forecasting
  - Energy purchases
  - Capacity purchases
  - Renewable energy certificates (RECs)
- Retail operating costs
- Non controllable costs
  - Network charges
  - Market-related fees and charges
- Retail margin

↓

Allocate efficient costs to different customer classes, to reflect costs of service provision

↓

Determine structure of tariffs for each customer class to recover required revenue for each class

↓

Assess impacts of proposed tariffs on customers, Synergy, Government finances

↓

Propose regulatory arrangements for future price reviews

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.

- 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); for example, timing capital investments so that costs are minimised over the long-term, and to 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 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 requires to provide its services to the required standard.

Competition is the most 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 competition.

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 in Western Australia is part capacity and part energy market,[18] whereas the National Electricity Market (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 interstate estimates. 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.

[18] 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 such as 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 determine the efficiency of each type of Synergy's costs in this draft report. The cost components of this proposed 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 Wholesale Electricity Market;
- ancillary service costs, paid by Synergy to the IMO to recover the costs of services administered by System Management, 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 on Mandatory Renewable Energy Targets;
- costs to Synergy of meeting its reserve capacity requirement;
- 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 this 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, so the Authority has examined the assumptions used by Synergy in its demand forecast models, as well as 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.

Non Controllable Costs

Some costs are outside the control of Synergy, so these costs 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, Mandatory Renewable Energy Target (MRET) quantities and costs, and costs of unhedged reserve capacity requirements (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 the third revised Access Arrangement (AA3). Network charges typically account for around 33 per cent of the total retail tariff, excluding the TEC (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 competition.

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 <u>of</u> its investments, to recover the costs of the depreciation of its assets over their useful lives.

Retail Margin

Again, the question when setting a retail margin for Synergy is what margin would an efficient retailer, operating in a competitive environment, earn? The retail margin is a proxy for the return on investment, such as the weighted average cost of capital applied to the asset base of other regulated service providers. However, in the case of 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 draft 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.

>5.704
<18.25 kW

- 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 cost). 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 cost 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 and 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 separated the cost stack into its fixed and variable components. By assessing each customer category individually and allocating an appropriate proportion of fixed and variable costs to each of these categories, cost reflective tariffs have been determined for each customer class.

In determining the efficient cost for each customer class, the Authority has regarded 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.

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

Chapter 2 Inquiry Approach

2.2 Current Process for Setting Tariffs

The price for the generation of carbon dioxide must be attributed to the generator of the carbon dioxide. (Based on the fuel not on the output power produced). CO_2 costs must be kept separate from the $/GJ on which markups are usual in the commercial world.

For electricity, the total CO_2 costs for the generation of the purchased energy, this cost is then attributed as proportion of the energy used by the customer of the total.

For fuels which are burnt by the customer such as gas or petrol, the customer is to be charged directly for their contribution.

The 'Cost Stack' approach

Is the average cost of delivered energy each year. The use of kWh is peculiar to the electricity industry. The SI metric unit for Energy is the Joule which is even smaller. With both these units the price is in the low number of cents which makes the price of electricity seem artificially cheap.

The gas industry uses much more appropriate unit which is in multiples of Joules. As you would see in the gas prices table that I have added to the introduction. Alinta Energy is the exception in their retail pricing. To make pricing more realistic it should be priced in $/GJ. The price per unit should be removed from all Synergy's communications and replaced by either kWh or GJ.

See the "Synergy Prices Compared 2011/2012" following page xvi as an example.

The power generation and consumption is measured in Watts. The advertising for solar panels and inverters are quoted in kiloWatts, similarly for air conditioners, and a 10 A standard power point can supply a maximum power of 2.3 kiloWatt.

$$Energy\ (Joule)\ =\ Power\ (Watt)\ x\ time\ (second)$$

	Power		
Duration	**1 Watt**	**1 kW**	**1 MW**
Day	0.000 0864 GJ	0.0864 GJ	86.40 GJ
Week	0.000 605 GJ	0.6048 GJ	604.8 GJ

Fortnight	0.001 21 GJ	1.2096 GJ	1 210 GJ
Month	0.002 63 GJ	2.630 GJ	2630 GJ
Quarter	0.007 889 GJ	7.889 GJ	7 889 GJ
Year	0.031 56 GJ	31.56 GJ	31 557 GJ

1 year = 31,556,806 seconds, 1 GJ = 1, 000,000,000 J

$$Cost\ of\ Energy\ (\$) = Energy\ (GJ)\ x\ tariff\ (\$/GJ)$$

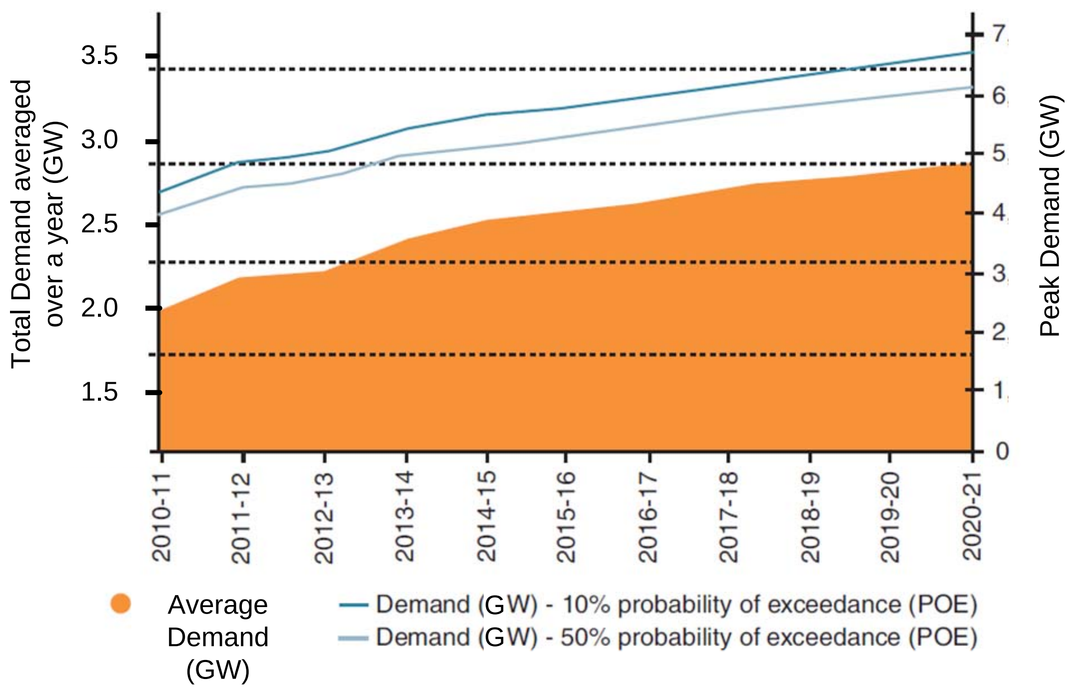
Measuring or calculating the average power enables predictions of the price for energy over any duration if the average power remains constant.

$$Power\ (Watt) = \frac{Energy\ (Joule)}{Time\ (second)}$$

The electricity infrastructure must be capable of the peak demand otherwise blackouts will occur.

The closer the average demand is to the peak demand the maximum value is obtained from the infrastructure. If the capacity and energy purchases are for similar powers the cost to Synergy is minimised.

Figure 8: Forecast Average and Summer Peak Demand



http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/WAs_Energy_Future/Alan%20Hughes.pdf page 14

Variations from the Public Utilities Office's predictions can be caused by;

- Variations in the age structure of the population served by the SWIS. Last year's census will be released by the Australian Bureau of Statistics from June this year.[1] The variation in age structure will change the times of average and peak demand.
- Climate change[2] will change the power consumption due to air-conditioners and electric heating.

Focussing on demand management in electricity tariffs will reduce the costs to Synergy.

[1] http://www.abs.gov.au/websitedbs/censushome.nsf/home/data?opendocument#from-banner=LN
[2] http://www.bom.gov.au/climate/

Estimate Synergy's efficient costs of service provision
(= revenue requirement)

- Wholesale energy and capacity purchases
  - Contract efficiency
  - Demand forecasting
  - Energy purchases
  - Capacity purchases
  - Renewable energy certificates (RECs)
- Retail operating costs
- Non controllable costs
  - Network charges
  - Market-related fees and charges
- Retail margin

Renewable Energy Certificate (LGC or STC) = 1MWh/year = 114.1 Watts on a continuous average. The LGC or STC goes to the owner of the renewable generator and not the retailer.[3]

Retail Costs

Why are Synergy residential customers being charged $147 per year where as Alinta Energy residential customers are being charged $63?

Similarly for small business customers $139 and $54 pa respectively?

The measurement of power consumption at the customer site.

The NBN will allow every customer to have a meter which is connected to the retailer's server. This means that the display indicate the current power consumption, your long term power consumption, the current account balance. This also enables the retailer to use prior payment for energy supply. This will remove bad debts for retailers. Those who cannot afford energy supply can be assessed by Community Services.

Allocate efficient costs to different customer classes, to reflect costs of service provision

[3] http://ret.cleanenergyregulator.gov.au/certificates

Domestic/Community Electricity & Gas Prices 2011/2012 graph shows the relationship between power consumption and price over a wide range. These Synergy plans are very similar. Alinta Energy has a similar shape but the tariffs are lower. Petrol by comparison has no supply charges only consumption with no variation in rate.

The timed Large business Plan is the cheapest and the untimed small Business the most expensive which is a quantity discount for high powered users.

The way to minimise the costs of service provision is to minimise the variation of the power consumption particularly high peaks when a substantial proportion of the consumers make their peaks at the same time.

The smaller the variation in power consumption minimises the costs because thinner wires can be used, smaller transformers and power stations. Currently the average consumption is 25 % of the peak consumption. If the peaks are reduced the average consumption can be increased without additional cost except for the fuel used. (If that is renewable then there is no additional cost!)

Reducing the power consumption variation

All power should be charged in the following fashion:

The sum of the following;

- *Base load* The $/GJ for purchasing of all power supplied to the network at the average power for the whole of the previous 5 years.
  - o This price not only includes purchases from large generators but also from small generators which are commonly customers as well.
- Divide the customers into the following groups
  - o Domestic/Community
  - o Business
  - o Industrial

  Distribution charge The $/GJ each group for the cost of providing the average power for the whole of the previous year. (includes maintenance costs)

- *Peak load* Charge for the energy used when the power deviates from the yearly average. The $/GJ will be greater than one used for base load to encourage the reduction of power consumption variation

- Calculated by $Energy\ (GJ) = \frac{(Power\ now\ (kW) - Pnwav(kW))\ x\ time\ (s)}{1{,}000\ 000}$
- This calculation is performed in the power meter once per second and accumulated over the measurement period
- Also the consumers' average power is measured once per second and averaged with the previous measurement in the power meter.
- The "Pnwav" is the long term network average for each consumer in this category.
- The charge is positive your power consumption is above average
- Negative values ignored.

Determine structure of tariffs for each customer class to recover required revenue for each class

What is the proportion of customers who's average power consumption is

- less than 76.5 W[4] = $146.61 pa @ 60.75 $/GJ, which is the A1 supply charge for a year
- <10 W (88 kWh per year) = $19.17 pa @ 60.75 $/GJ. This is typical of standby power in appliances.
- These values should detect vacant properties.

Is it worth having a supply charge?

The Customers' account is calculated as follows;

Account Date 12/03/2012 09:00:00 to 23/03/2012 11:28:23 = 114 776 seconds

Average power consumption = 704 W

$$\text{Average energy purchased (GJ)} = \frac{704 \text{ x } 114\ 776}{1\ 000\ 000\ 000} = 0.8080 \text{ GJ}$$

Cost of your average power = 0.8080 x 36.45 $/GJ **= $29.45**

Distribution charge = 0.8080 x 12.15 $/GJ **= $9.82**

Peak consumption charge =.1616 GJ x 72.54 $/GJ **= $11.72**

[4] 76.5 W =2.41 GJ per year = 670 kWh per year. 2.41 GJ = $146.61 @60.75 $/GJ

Retail margin = 0.00004817 \$/s x 114776 **= \$2.13**

Carbon Dioxide = 0.8080 x .258 t/GJ = 0.2085 t = .2085 x \$23/t **= \$4.79**

Pay \$ 56.91

for 0.8080 GJ of electricity supplied at an average of power of 704 W

Assess impacts of proposed tariffs on customers, Synergy, Government finances

The use of supply charges penalises the people who are minimise their power consumption because they cannot afford large energy bills.

Will the removal of supply charges decrease the subsidy costs for customers who will have their power cut off.

One of the current pressures on infrastructure is increasing power consumption particularly at peak times. A reduction of the variation slows the increase in power charges.

Propose regulatory arrangements for future price reviews

Investigation into the following;

Retailer can source all forms of energy and sell all of them.

For example Synergy, Alinta, and WA liquid fuel companies can sell electricity, gas or even petrol

All energy is to be priced in Dollars/GigaJoule ($/GJ) to allow easy comparison of all types of energy prices. This will not only cause competition between retailers but also between energy sources.

Purchasing of energy

- *Base load* The $/GJ for purchasing of all power supplied to the network at the average power for the whole of the previous 5 years.
    - This price not only includes purchases from large generators but also from small generators which are commonly customers as well.
- Divide the generators into the following groups
    - <10 kW (Domestic/Community)
    - 10 – 100 kW (Business)
    - 100 kW – 1 GW Industrial
    - >1 GW (Major generator)

  This power is the installed capacity or peak power capacity.

  Connection to the network charge The $/GJ each group for the cost of providing the average power for the whole of the previous year. This covers any costs of connecting the generator to a point in the network which can distribute that peak power.

- *Peak generation* cost for the energy used when the power deviates from the yearly average. The $/GJ will be greater than one used for base load to encourage the reduction of power consumption variation
    - Calculated by $Energy\ (GJ) = \frac{(Power\ now\ (kW) - average\ power(kW))\ x\ time\ (s)}{1,000\ 000}$
    - The “average power” is the long term network average.
    - The charge is positive your power consumption is above average
    - Negative values ignored.

2.2.2 Economic Efficiency

An important efficiency is not mentioned.

$$\boldsymbol{Generation\ efficiency}\ (\%) = \frac{Power\ out}{Power\ in}\ x\ 100$$

Power out is the voltage x current to be measured and averaged over the same period as the power input.

Power in depends on the fuel and flow rate

Black coal

> contains 27 GJ/tonne. 1 Mtonne per year = 855.6 MW.
>
> 855.6 MW produces 88,200 tonnes of CO_2 per year

Natural Gas

> Contains 39.3 x 10^{-3} GJ/m³ 1,000 m³ of NG per year = 12.14 kW
>
> 12.146 kW produces 62.14 tonnes of CO_2 per year

Renewable sources

> The efficiency of these sources can also be calculated and they do not produce carbon whilst producing electricity or pumping water.

The generation efficiency can be calculated for individual generators, individual generation companies or all generators on the distribution system. The efficiency will vary depending on how much power is being produced.

$$\boldsymbol{Distribution\ or\ transmission\ efficiency}\ (\%) = \frac{Power\ out}{Power\ in}\ x\ 100$$

Distribution efficiency can be calculated for individual components of the distribution system, individual power line routes or the total distribution system. The efficiency drops as a power line becomes longer. The efficiency will also be poorer if there is "leakage" caused by arcing across insulators and the conversion of electricity to heat in corroded joins and on wires.

3 Wholesale Electricity Costs

3.1 Background

In this section, the efficient costs required by Synergy to purchase wholesale electricity are examined. The following sections examine Synergy's retail operating costs (section 0), non-controllable costs, such as network charges, ancillary services costs and market fees (section 5), and Synergy's retail margin (section 6), in order to determine Synergy's cost reflective tariffs (section 7).

The Terms of Reference require the Authority to pay particular attention to the efficiency of Synergy's procurement of wholesale electricity and renewable electricity certificates (RECs). Over the past four years these two items have contributed approximately 57 per cent of Synergy's total aggregated costs[19] for the period.

3.2 Public Submissions

3.2.1 Wholesale Energy Procurement

The issues paper asked for comments on how the efficiency of Synergy's wholesale procurement should be assessed, and what indicators should be used for such an assessment.

Synergy

Synergy listed in its submission the following factors that would need to be considered by the Authority when assessing the efficiency of wholesale energy procurement.[20]

- Synergy's long term forecast electricity requirements (energy, capacity and renewables) at the time of procurement;
- demonstration of a competitive, open and fair tender/ selection process or, if not tendered, comparison against valid market benchmarks;
- the fit of any new contract against Synergy's existing supply portfolio (i.e. the impact of the new contract on Synergy's supply portfolio costs);
- legislative and other requirements at the time of procurement (in particular, Synergy's obligations under the Vesting Contract to displace certain amounts of capacity and associated energy, using a tender process within certain timing constraints, during the period when a significant number of the contracts under review occurred);
- due diligence undertaken by the Office of Energy and the Department of Treasury and Finance on behalf of the Minister for Energy, who in approving transactions assessed the efficiency and cost competitiveness of the arrangements; and
- allocation of risks arising to Synergy or the independent power producer (e.g. market risk, reliability risk, construction risk).

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

[20] Synergy submission on issues paper, pp3-4.

Horizon Power

Horizon Power submitted that Synergy should be able to demonstrate the efficiency of its wholesale electricity procurement processes; for example, through open tender processes, transparency around the selection criteria applied to tenders, and timely announcement of the successful bid.

Alinta

Alinta supported a thorough assessment by the Authority of Synergy's wholesale electricity procurement costs, particularly the commercial aspects of the vesting contract, to determine whether Synergy's purchasing strategy is efficient (compared to an efficient benchmark retailer). Alinta recommended that the Authority examine the replacement costs of generation to assess the efficiency of Synergy's wholesale purchasing costs. Alinta submitted that it would be concerned if the current arrangements between Verve Energy and Synergy were to further entrench the position of these parties in the wholesale market. Alinta also recommended that the Authority examine all contracts entered into by Synergy to determine whether the allocation of risk between the contract parties is efficient.

3.2.2 Renewable Energy Certificates

In the issues paper, the Authority also asked for comments on how the efficiency of Synergy's procurement of renewable energy certificates (RECs) should be assessed, and what indicators there are for efficient procurement of RECs.

Synergy

Synergy noted in its submission that there are a number of factors that would need to be considered in assessing the efficiency of its RECs procurement.[21]

- The legislative framework existing at the time of procurement;
- The impact of various Commonwealth and State government policy setting on the short and long term price of RECs; and
- The prudency of covering REC exposures with a range of long term, medium and short term procurement strategies;
- The need to hedge the impact of uncertain future carbon prices on REC prices over long-term REC contracts, by bundling of RECs with renewable energy (in markets in which Synergy participates i.e. the WEM).

Synergy also noted that long-run forecasts of REC prices will reflect expectations regarding the cost differential between renewable and non-renewable energy, inclusive of the carbon price.

[21] Synergy submission on issues paper, p4.

Horizon Power

Horizon Power submitted that Synergy should be able to demonstrate efficiency in its REC procurement, as for its wholesale energy procurement (e.g. through transparent and competitive processes). Horizon Power's view was that Synergy should be able to show that its cost of procuring renewable energy or RECs is less than the equivalent penalty payment.

Alinta

Alinta recommended in its submission that the Authority examine closely whether Synergy has met its REC liabilities at least cost, taking into account the availability of a national market for RECs.

3.2.3 Carbon Costs

Several submissions commented on how the new carbon price should be included in the modelling of cost reflective tariffs.

Synergy

Synergy submitted that the costs associated with federal legislation regarding carbon pricing will be borne by generators and passed on to retailers, with the actual cost to each generator depending on a range of factors, such as the generator's level of carbon intensity, fuel type, and operating efficiency. The costs would therefore increase Synergy's electricity purchase costs, which Synergy would pass through to its retail customers. Synergy recommended that the Authority include the costs associated with carbon pricing in its modelling of retail tariffs. Synergy also noted that, given the uncertainty around the impact of carbon pricing, there should be scope for revision of tariffs to reflect actual costs once these are established.

Horizon Power

Horizon Power submitted that there is considerable uncertainty regarding the impact of carbon pricing on retail electricity tariffs, and noted that the Authority's recommendations on Synergy's retail tariffs would cover both the fixed price and floating price phases of the carbon pricing scheme.

Horizon Power also noted that, in addition to higher electricity generation costs, there are other costs associated with carbon pricing faced by retailers, due to additional administrative requirements, such as changes to billing systems, customer management and information provision. This was an important consideration for Horizon Power, given the diversity and regional spread of its customer base.

Horizon Power was unclear how the carbon price would be integrated with the uniform tariff. For example, Horizon Power (and other retailers) could adopt the same carbon "element" in retail tariffs as Synergy, or they could develop their own retail carbon element, taking into account their own eligible carbon emissions for self-generation and Power Purchase Agreements, probably on a monthly basis.

Horizon Power also queried how the variability in the carbon price once the emissions trading scheme is introduced would be dealt with in customer billing. Horizon Power supported the approach set out in the federal legislation, which is to use an average of the carbon price over the previous six months for billing purposes when the carbon price transitions from a fixed price to a floating price.

Energy Supply Association of Australia (esaa)

esaa noted the high degree of uncertainty regarding the future impacts on wholesale energy costs of the Federal Government's Clean Energy legislation. It recommended that any price setting methodology considered by the Authority incorporate a mechanism to allow the costs associated with carbon pricing to be passed on efficiently and promptly, during both the fixed price and floating price phases of the scheme.

Alinta Energy

Alinta considered that Synergy should be allowed to recover its carbon costs, based on the average carbon intensity of electricity generation in the SWIS. Alinta noted that Synergy may have limited opportunity to reduce its carbon exposure over the short term, due to its long-term electricity supply contracts. However, Alinta recommended that any allowance for cost recovery provide incentives for Synergy to efficiently reduce its carbon costs.

Chamber of Commerce and Industry (CCI)

CCI submitted that it was important to understand and accurately reflect the costs associated with carbon pricing and other government renewable energy schemes in moving towards cost reflective tariffs.

3.3 Synergy's Demand Forecasts

A key input into Synergy's wholesale electricity procurement model is the demand forecasts at half hourly level. 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.

3.3.1 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.

Power consumption per customer in each tariff group, should be calculated on a yearly, seasonal and time of day. These values should be modified by climate variations.
The total demand needs to be multiplied by the number of potential customers from census data and business data.

Synergy's sales to commercial customers were reported as [redacted] GWh in 2010/11, which represents a [redacted] per cent reduction compared to the 2009/10 sales result.

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 SM1 (smart meter) tariff classes (82 per cent of total annual sales) and L1 customers in the small to medium enterprise category (12 per cent of total annual sales). State Budget 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 residential 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, used to forecast contestable customer demand, contains assumptions for various scenarios of tariff increases (transition to cost reflective prices), 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, international economic conditions (see 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 estimate MWh consumption forecasts for different groups of contestable customers.

3.3.2 Authority Assessment of Synergy's Demand Forecasts

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

Synergy's forecasts for total demand have been very close to actual total demand, with a variation of less than 2 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). However, in considering these 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. Due to the small number of customers on each tariff, these variations between actual and predicted demand do not materially impact on the overall findings of the Authority.

Demand forcasting should not use MWh/year because it cannot track variations in consumption. Power consumption in MW so consumption can be compared between seasons, peaks, troughs to see how close the consumption is to the long term average.

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 (e.g. 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 competition).

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 due to day to day demand being largely driven by weather and so demand forecasts would inevitably involve trying to forecast daily weather one year ahead, a task that not even the Bureau of Meteorology can undertake.

- The total non-contestable demand takes two factors into account, being growth in households and household consumption. Growth in households is based on data sourced from a reputable agency (BIS Shrapnel). Household consumption growth is estimated taking major factors such as the penetration of air-conditioning, energy efficiency trends and photovoltaic (solar panels) take up into account. The year to year change in residential demand is very small relative to total demand itself, so even large errors in the estimation of this change will have a minor impact. The process appears to be sufficiently comprehensive and robust, given the stability of residential demand over time.

- Contestable demand is forecast based on industry growth and lost and new customers estimations. 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 one to two per cent and have not been biased toward being positive or negative.

Based on the above, the Authority accepts Synergy’s demand forecasts.

.

Draft Finding

Synergy's Demand Forecast

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.

3.4 Purchase of Wholesale Electricity

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

- Based on the long-run 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-run 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.

With regard to wholesale electricity cost the terms of reference require the Authority to consider:

> "the efficiency of Synergy's procurement of wholesale electricity; and...determine the efficient cost reflective level for each regulated tariff".

The Authority has addressed the issue of efficiency of Synergy's procurement of wholesale electricity by evaluating the bilateral contracts that Synergy has entered into, including the vesting contract that exists between Synergy and Verve Energy. These contracts include agreements for energy and the capacity that Synergy is required to procure.

The Authority has examined Synergy's forecast actual costs via its contracting of capacity and energy and the dispatch of energy from these contracts. However, to determine Synergy's efficient cost of wholesale energy, and to set tariffs based on efficient costs, the Authority considered the cost that would be expected in an effectively competitive market, consistent with the principles outlined in section 8.2. To this extent, the Authority has considered the Long Run Marginal Cost to be an indicator of the efficient level of cost.

In the long run, the market price for supply of capacity and energy combined must gravitate towards the LRMC in a well functioning market. That is, the LRMC of electricity generation can be considered a proxy for the cost that an efficient generator will seek to recover from the market over the long term. In such a market, a price reflecting the LRMC will provide investors with reasonable confidence that they will earn a satisfactory return on their investment over the life of the generation plant, and ensure that consumers do not pay any more than is necessary.

Wholesale prices are naturally volatile, being driven by market expectations regarding supply and demand conditions and government policy decisions. Prices set based on LRMC will provide a smoother price path for consumers, in the long run, thereby reducing uncertainty for customers.

Finally, LRMC has been used by most regulators in Australia to either set cost reflective tariffs or a tariff range. LRMC has been used in NSW by IPART in its price determination for retail.[22] LRMC has also formed the basis for the determination of efficient wholesale costs in SA by ESCOSA.[23] Tasmania has also used LRMC to establish its wholesale electricity cost.[24]

3.4.1 Assessment of Synergy's Contracts

Synergy has entered into various bilateral contracts to purchase its wholesale electricity. Most of these contracts were competitively procured, except for the vesting contract that was assigned to Synergy by the State Government.

There are two aspects to the assessment of efficiency in wholesale electricity procurement.

- 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, including contracts Synergy entered into to meet its renewable energy certificate 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, 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

[22] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity — Final Report*, March 2010

[23] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path Final Inquiry Report & Final Price Determination*, December 2010

[24] OTER, *Investigation of maximum prices for declared retail electrical services on mainland Tasmania, Final Report*, October 2010.

3.4.1.1 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 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 (and hence competition) in the electricity generation and retail sectors and ensure that energy was competitively procured.

In 2010, the State Government established revised terms and conditions in relation to the contractual arrangements between Verve Energy and Synergy. This has led to the abolishment of the original vesting contract and the implementation of the replacement vesting contract. The most significant difference between the original vesting contract and the replacement vesting contract is 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 Authority has raised its concerns previously with regard to the lack of the pro-competitive features in the revised vesting contract which had been included in the original vesting contract and the adverse impact this was likely to have on private investment in the future. The Authority is also aware that the replacement vesting contract was developed mainly to mitigate the financial losses reported by Verve Energy in the 2007/08 and 2008/09 financial years. However, prior to the replacement vesting contract 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.

Other Contracts

The Authority has sought to review the efficiency of Synergy's third-party contracts in relation to 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, utilising the following approaches:

- 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; and
- modelling of Synergy's average wholesale energy cost on a portfolio basis against an external benchmark of the efficient costs of supplying energy to meet Synergy's total load shape.

The consultant's approach and key findings are summarised below.

Frontier's desktop review of Synergy's third-party contracts has 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;
- VESP09;
- 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 includes information on Synergy's objectives for entering into the contracts that were reviewed as well as brief descriptions of those contracts.

3.4.1.2 Findings

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 which 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 examining 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.

3.4.1.3 Authority Comments

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 entering into the contracts was a reasonable decision at the time. Synergy's documentation demonstrated an understanding of the key risks to the business, mechanisms to mitigate these risks in its dealings with counterparties and the market and economic circumstances at the time it entered into the contracts reflected information that was available at that time.

However, the replacement vesting contract was not procured under the standard processes used by Synergy.

3.4.2 Is Synergy Using its Existing Contracts Efficiently?

The second aspect of wholesale electricity purchasing efficiency is 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).

Consultant Marsden Jacob Associates (MJA) was appointed 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.

3.4.2.1 Consultant Assessment

To provide an estimate of Synergy's efficient electricity purchasing costs, the consultant MJA built a linear programming model to determine 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 estimates Synergy's efficient procurement costs over the five year period from 2011/12 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, the 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 costs include the estimated impact of the carbon price that will apply from 2012/13.

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;
- specifying whether a contract is to start up or shut down within a given time interval;
- ensuring that 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 replacement vesting contract provides for a new set of monthly minimum and maximum constraints for each month over the 60 month period of the contract.

The model uses as an input Synergy's demand forecasts for contestable and non-contestable customers. 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 in the model information that may reduce demand uncertainty closer to the time of dispatch, such as short-term weather forecasts[25].

3.4.2.2 Authority's Assessment of Synergy's Contracts

Table 5 below presents the Authority's estimates of Synergy's wholesale electricity costs, based on the modelling of the efficient dispatch of Synergy's existing suite of contracts.

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.

The Authority notes that, based on the carbon intensity of Synergy's forecast dispatch, the carbon price adds $16.94 per MWh in 2012/13 on an energy sent out basis, rising to $21.77 per MWh in 2015/16. Customers should not have to pay extra for poor efficiency power stations or profit on a tax.
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 services costs.

The replacement vesting contract 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.
The CO2 costs are to be charged on the generator purchasing carbon based fuels. Carbon costs are to be apportioned to base load or peak billed separately and totalled in those categories.
The individual customers' carbon costs is their proportion of the total energy supplied in the billing period. The retailer must not be able to make a profit on a tax. (0.663 tonnes carbon/tonne of black coal, 0.000552 tonnes carbon/cubic metre of natural gas.)

3.4.3 Consultant's Approach to LRMC Estimation

Frontier used an LMRC) approach to estimate the cost reflective tariff for each tariff class. The LRMC represents the least cost of generation that would be incurred in the long run, to meet the demand from Synergy's customers. There are various methods of estimating the LRMC. Frontier has adopted the "stand alone" LRMC approach (also referred to as a "greenfield" approach), which assumes that there is no existing generation and an optimal mix of generation can be built to match demand at any point in time, in contrast to an actual cost approach which considers the existing mix of generation in the market. This is based on an assumption that, in the long run, the mix of electricity generation will converge on the most efficient outcome. Varying demand at any point in time, on a half hourly basis, is termed as the load shape. The approach is applied to the load shape of each tariff class, to determine the efficient costs for each tariff class individually.

The Frontier Economics final report on Synergy's LRMC will be available on the Authority website[26].

Frontier used its proprietary least-cost optimal investment electricity market model ([redacted]) to determine the LRMC for each tariff class. Frontier used [redacted] to calculate the least-cost investment requirement, an estimate of LRMC of meeting load, and the cost of any plant necessary to meet any regulatory obligations.

3.4.4 Consultant's Findings

Using the base case assumptions (taking the midpoint from a range of forecast fuel costs, a WACC of 7.8 per cent and the Commonwealth Treasury's forecast carbon price), Frontier estimated that the carbon-inclusive efficient cost for Synergy's total load was $102.30 per MWh for 2012/13 (real, in 2011/12 dollars). 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 Authority has adjusted the LRMC to account for the additional capacity cost that a new entrant will 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. This has resulted in the equivalent of between 34 per cent and 41 per cent buffer above that allowed by Frontier's modelling.

The Authority concludes that no efficient entrant would be able to avoid these costs, given the IMO requires the same over contracting from other retailers. Consequently, the Authority has added the additional capacity, valued at the determined and forecast IMO Reserve Capacity Price, to the consultant's estimate of LRMC. The results are shown in the table below.

[26] www.erawa.com.au

Energy price table converted to $/GJ

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

$/GJ, nominal, sent out	2012/13	2013/14	2014/15	2015/16
Wholesale electricity cost (incl. Capacity)	32.06	31.64	30.44	31.80
Carbon Bill Separately	9.89	10.39	10.92	12.48
Total	**125.31**	**124.31**	**120.49**	**126.96**

Source: ERA Analysis
Note: Figures must be adjusted for line losses for conversion to consumer prices.

For 2012/13 and 2013/14 the actual cost of wholesale energy is lower than the LRMC cost. However, the actual carbon cost is much higher than the LRMC. This is because the Authority's consultant estimates that a new entrant would rely entirely on gas generation, mainly Combined Cycle Gas Turbines (CCGT) with some Open Cycle Gas Turbine (OCGT) plant for peak supply, compared with Synergy's current mix of coal, gas and renewable generation. From 2014/15 onwards, the wholesale energy cost of the LMRC is lower than Synergy's estimated contractual dispatch cost, with the carbon price further amplifying the difference.

3.4.5 Conclusion on procurement of wholesale electricity

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 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.

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 will use the adjusted LRMC in its analysis.

3.4.6 Procurement of RECs

In the issues paper, the Authority also asked for comments on how the efficiency of Synergy's procurement of renewable energy certificates should be assessed, and what indicators there are for efficient procurement of RECs.

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 Scheme (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. (For the sale of each MWh of GreenPower, Synergy is required to surrender one LGC.)

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

Synergy

Synergy noted in its submission that there are a number of factors that would need to be considered in assessing the efficiency of its RECs procurement:[27]

- the legislative framework existing at the time of procurement;
- the impact of various Commonwealth and State government policy setting on the short and long term price of RECs;
- the prudency of covering REC exposures with a range of long term, medium and short term procurement strategies; and
- the need to hedge the impact of uncertain future carbon prices on REC prices over long-term REC contracts, by bundling of RECs with renewable energy (in markets in which Synergy participates i.e. the WEM).

Synergy also noted that long-run forecasts of REC prices will reflect expectations regarding the cost differential between renewable and non-renewable energy, inclusive of the carbon price.

Horizon Power

Horizon Power submitted that Synergy's should be able to demonstrate efficiency in its REC procurement, as for its wholesale energy procurement (e.g. through transparent and competitive processes). Horizon Power's view was that Synergy should be able to show that its cost of procuring renewable energy or RECs is less than the equivalent penalty payment.

Alinta

Alinta recommended in its submission that the Authority examine closely whether Synergy has met its REC liabilities at least cost, taking into account the availability of a national market for RECs.

[27] Synergy submission on issues paper, p4.

Synergy's Approach to REC Procurement and Forecasting

LRET Liability

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

1. REC purchase agreements with Verve Energy, these RECS having been 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;

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

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

4. purchase agreement for RECs produced from the Collgar Wind Farm;

5. purchase agreement for RECs produced from the Mount Barker Community Wind Farm; and

6. 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 period. These were purchased by using combination of spot and forward contracts and will cover Synergy's forecast LRET exposure to 2016. Synergy's forecast LRET exposure is shown in Table 7 below:

Table 7 Synergy's Forecast LREC Expenses ($/LGC)

2012	2013	2014	2015	2016
$44	$47	$50	$53	$58

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.

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. Currently, Synergy is covering its exposure by purchasing STCs from the market at less than the clearinghouse price.

3.4.6.1 Authority Assessment of Synergy's REC Procurement Forecasts

The Authority has examined the assumptions used by Synergy in its REC procurement, considering indicators for the efficient procurement of RECs using a process of benchmarking Synergy's forecasts against those published in other jurisdictions.

In considering the LREC procurement forecasts adopted by Synergy, the Authority has considered Synergy's forecast LGC price which is derived from existing bilateral contracts. As these LGC prices have been locked in by bilateral contracts they will provide a hedge against any future volatility in the LREC market, with the contracted LGC prices being around 50 per cent of the LRET penalty price Synergy would expect to pay over the forecast period.

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, the Authority finds this assumption to be reasonable given the potential volatility of the new SRES market. 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.

3.4.7 Costs of Carbon Pricing As previously discussed.

The current generation in the SWIS consists of a mix of coal, gas and renewable sources, with an average carbon intensity of approximately 0.74 tCO2/MWh for Synergy's estimated dispatch in 2012/13[28]. 0.206 tCO2/GJ does not match National greenhouse accounts

The stand alone LRMC, which optimises generation based on costs which include carbon pricing, utilises entirely gas-fired (mainly CCGT) generation which has a lower carbon intensity. The Authority's consultant estimates a carbon intensity of 0.43 tCO_2/MWh for CCGT generation and 0.5 tCO_2/MWh for OCGT generation. 0.139 tco2/GJ

0.119 tCO2/GJ

As noted above, this leads to a substantial difference per unit and total cost of carbon pricing between the two generation mixes. This is shown in Table 8 below.

Table 8 Carbon Impact on LRMC of Utilising Gas-Fired Generation 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
LRMC Carbon c/kWh $/GJ	1.09 $3.03	1.15 $3.19	1.21 $3.36	1.38 $3.78
Actual Carbon c/kWh $/GJ	1.87 $5.19	1.99 $5.53	2.11 $5.86	2.41 $6.69
LRMC Carbon $m	$87	$90	$95	$108
Actual Carbon $m	$149	$156	$165	$188

Source: ERA Analysis

3.4.7.1 Authority Comments

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

The extent of the carbon cost that a generator will face depends on, amongst other things, the carbon intensity of the generator. For example, in its calculation of LRMC, Frontier Economics has assumed a carbon intensity of a coal based generator as about 0.84, .233 tco2/SJ whereas the carbon intensity assumed for an open cycle gas plant is 0.43. .119

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 passed on to

[28] The Authority has accepted Synergy's estimated actual carbon intensity for purposes of this draft report and will consider it in further detail before releasing the final report.

http://www.climatechange.gov.au/~/media/publications/greenhouse-acctg/national-greenhouse-accounts-factors-july-2011.pdf 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). In its publication Strong Growth, Low Pollution; Modelling a Carbon Price (2011) the Federal Government noted that:

> "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 such, highly carbon intensive generators will incur some losses in their profitability, leading to lower returns to their shareholders. The level of decrease in their profitability would depend on a range of factors, including any Government-funded assistance.

Verve Energy recognises 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 notes 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 did not receive any Federal Government assistance.

3.4.7.2 Findings

As outlined above, the Authority does not consider passing through the full 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.

The Authority recognises that it may require up to two years for Synergy to re-negotiate its contracts to ensure that only an efficient level of carbon cost is recovered in its tariffs. The Authority also notes that Verve Energy has earned a significant return in the last financial year, and therefore any re-negotiation to reduce the carbon cost pass through should not impact on Verve Energy's financial viability.

3.5 Conclusion on Efficient Wholesale Electricity Purchasing Costs

The Authority has concluded that Synergy has procured wholesale electricity efficiently with the exception of the replacement vesting contract, which was imposed upon Synergy. Furthermore, the Authority has concluded that Synergy's planned dispatch against its available suite of contracts is efficient in the context of the uncertainty that Synergy faces.

The test for whether existing tariffs are efficient 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. The Authority has calculated the wholesale electricity cost based on the LRMC of the market, which is calculated by the total costs of supply of a new entrant in the market.

In calculating the LRMC, the Authority is mindful that Synergy has a reserve capacity requirement imposed on it by the IMO and that no new entrant could avoid this commitment, although it could potentially fulfil this requirement at a lower cost than Synergy.

The LRMC, which is based on gas-fired generation, is based on a lower average carbon intensity than Synergy's forecast dispatch from its existing contracts, which include high-carbon coal generation, so the total and per-unit carbon cost is lower than Synergy's actual carbon liability.

While LRMC provides an indication of the efficient level of cost over time, the Authority recognises that generators may not be able to respond immediately to the carbon price and has, therefore, delayed the adoption of the lower LRMC cost for two years. The Authority has adopted the actual contract costs for Synergy in the first two years; being 2012/13 and 2013/14, followed by the LRMC cost approach for the following two years; 2014/15 and 2015/16.

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

$/GJ

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

$30.44 $30.80

	2012/13	2013/14	2014/15	2015/16
Wholesale electricity cost (incl. Capacity)	[redacted]		109.58	114.49
Carbon			10.92	12.47
Total			**120.49**	**126.96**

$3.03 $3.46

Source: ERA Analysis

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

3.6 Draft Recommendation

2) The Authority considers Synergy's energy consumption forecasting process to be efficient and accepts Synergy's energy forecasts for the period 2012/13 to 2015/16.

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

4) The Authority considers that Synergy may not be able to respond immediately to the carbon price. As a result, while Long Run Marginal Cost

(LRMC) provides an indication of the efficient level of cost over time, it is more appropriate 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. The Authority notes that:

a) The LRMC is slightly lower than Synergy's forecast average cost of dispatch in 2012/13, mainly due to a lower carbon intensity of the new entrant generator; and

b) From 2014/15 onwards, the LRMC is substantially below Synergy's forecast average cost of dispatch, due to both a lower energy cost and a lower carbon cost.

5) The Authority considers Synergy's procurement of Renewable Energy Certificates (RECs) to be efficient.

4 Retail Operating Costs

4.1 Background

Synergy's remaining 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). Synergy's capital expenditure is also low (around $7 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 Public Submissions

Synergy

Synergy submitted that as an electricity retailer, its capital expenditure is not large and relates primarily to the replacement and updating of IT systems (software and hardware). Synergy noted that it had recently incurred capital costs that were higher than normal, in IT hardware for its new customer information system developed following its separation from Western Power in July 2010. Synergy submitted that this was a once in ten year level of expenditure.

Synergy supported the use of benchmarking as an appropriate approach to assessing operating efficiency. However, Synergy recommended that a range of factors that are specific to Synergy's business operations be taken into account in any comparison with other retailers; that is:

- there are no other retailers in Western Australia that operate in both the contestable and non-contestable markets, so comparisons would need to be with retailers in other states;
- Synergy has a smaller customer base and less scope for economies of scale than other major retailers;
- Synergy has no generation or network assets and is not able to allocate overheads across other such activities; and
- Synergy has some additional costs that are specific to its business, such as IMO market costs, Energy Ombudsman costs, and retail licence compliance costs.

Synergy also noted that it has a number of obligations due to its Government Trading Enterprise (GTE) status, including:

- concessions management to around 250,000 (or 30 per cent) of residential customers;
- the purchase of renewable energy under the Renewable Energy Buyback Scheme and administration of the Scheme;
- administration of the Feed-in Tariff schemes, which apply to around 70,000 (or 9 per cent) of residential customers; and
- some regulated fees and charges which do not allow for full cost recovery, such as meter tests.

Synergy also submitted that efficiency assessments and benchmarking should allow for the efficient costs of meeting legislative and other service standards.

Alinta

Alinta noted in its submission that there was a risk of the Authority establishing cost reflective tariffs based on current and actual expenditure by Synergy, without having sufficient regard to benchmark costs of other comparable retailers. Alinta supported the use by the Authority of benchmarking between Synergy and other retailers of comparable size in order to establish efficient levels of operating and capital expenditure. Alinta also noted that it was important for cost reflective prices to include a sufficient allowance for retail operating costs.

4.3 Service Standards

Synergy's main reporting requirement is undertaken as part of its electricity retail licence obligations.[29] 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,

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

access, customer service, and compensation payments). A copy of the report is available on the Authority's website[30].

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.

4.4 Synergy's Estimates of its Retail Operating Costs

Total Electricity Retail Operating Costs

Synergy provided the Authority with its estimates of its retail operating costs for 2010/11 and its forecasts for the period 2011/12 to 2015/16[31] as shown in 10 below:

Table 10 Synergy's Actual and Forecast Operating Costs 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]					

Source: Synergy

Note: Operating costs exclude depreciation, amortisation, interest, nomination fees and operating costs associated with gas sales activities.

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

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- 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 $85 for an average residential customer and $119 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

	Synergy's Estimated Annual Retail Cost for Average Contestable Customers ($ per Customer)	
Contestable Customer Type	2010/11 (Actual)	2012/13 (Forecast)
[redacted]		

Source: Synergy

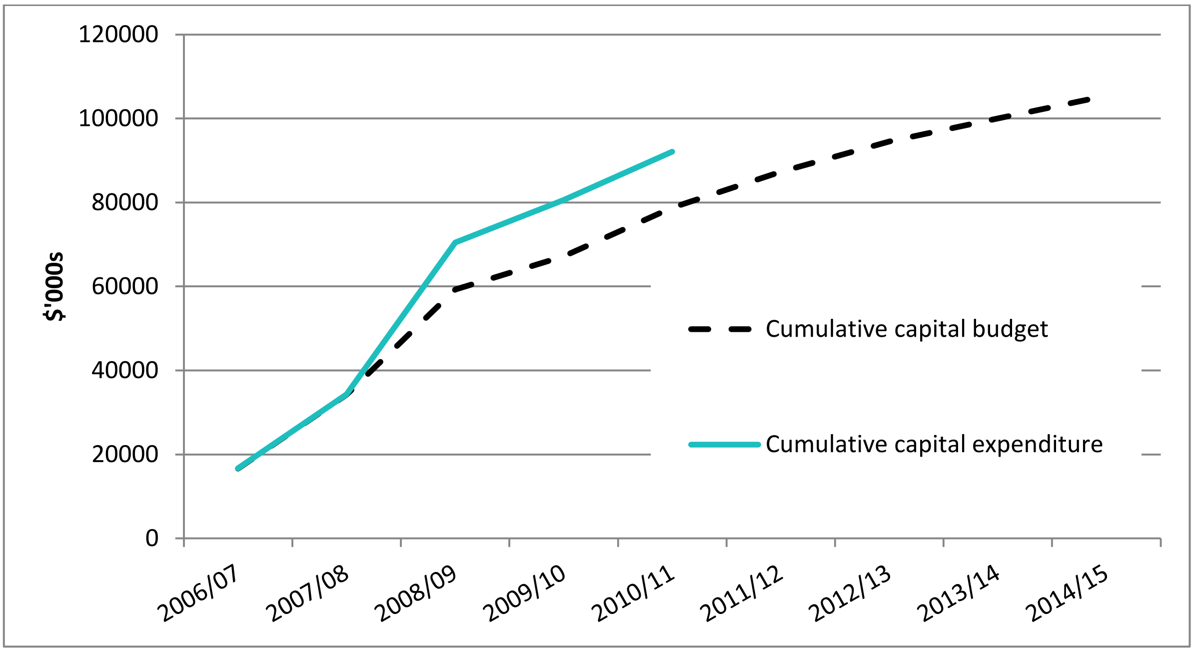
4.5 Synergy's Capital Expenditure

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[32] and by 2010/11 the total budgeted cost was estimated at $48.8 million,[33] 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.

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

4.6 Consultant Assessment

4.6.1 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.[34]

- 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.

[32] Department of Treasury and Finance (2005), 2006/07 Budget Paper No. 2 – Volume 3, p925

[33] Department of Treasury and Finance (2010), 2011/12 Budget Paper No. 2 – Volume 2, p616

[34] Frontier's report is available on the Authority's website.

- 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 no FRC.
- 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 achieved 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 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. Other regulatory decisions indicated that, in any case, economies of scope are unlikely to be substantial.

0.18 TJ/yr
5.7 kW

- 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 not significantly higher than that in other states (less than 1 per cent) and as a result the use of benchmarks from other states was 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 provided by Synergy as part the Office of Energy's Energy Market Review in 2007/08.

4.6.2 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. The Authority estimated Synergy's retail cost[35] for the same period to be $89 per annum

[35] The Authority adjusted Synergy's estimates by using consistent customer numbers for all purposes in this review

(nominal)for A1 customers in 2011/12. This estimate is consistent with recent retail operating cost benchmarks in other jurisdictions (once adjusted for the factors noted in 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. This is because changes in labour costs – which make up around 60 per cent of retail operating costs – can be accounted for by adjusting the allowance for retail costs annually in line with the labour price index (for total hourly pay minus bonuses in Western Australia). Further, it is difficult to determine what efficiency savings (such as those arising from a change in production technology) could be achieved by a retailer over the review period.

Frontier also noted that the benchmark operating costs include FRC related costs, such as costs of transferring customers, which would not be incurred by Synergy. As such, the benchmarked result is likely to overstate the operating costs for Synergy. However, Frontier notes that this is a relatively small cost and the extent of overstatement will not be too substantial.

Contestable Customers

Frontier notes that, unlike costs for non-contestable data, 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, medium to large businesses (contestable customers) are not regulated and 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.

4.7 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.

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 4.7.1.1), so depreciation is excluded from retail operating costs. Benchmarking comparisons have been careful to exclude depreciation from comparable retailers' operating costs for consistency.

Another important issue is the treatment of customer acquisition and retention cost. This cost is not included in Synergy's operating cost, although it is a relevant consideration. It's relevance to Synergy, and its inclusion in Synergy's total cost base, is discussed in section 6, under Retail Margin.

- 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) is an average across these regulatory decisions, some of which may include costs associated with full retail competition (FRC), and depreciation, and others which exclude these costs. This estimate will therefore approximate, but not underestimate, the efficient retail costs for non-contestable customers.
- Converting Frontier's estimate to 2011/12 dollars gives an estimate of $81.50 per customer, on average, for all regulated customers.
- This cost per customer represents the average operating cost across all regulated customers, i.e. customers consuming below 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, but instead relate to all regulated customers (i.e. all consumers consuming below 160 MWh), the average cost of $81.50 is applied across all regulated customers to derive the total operating cost. If a larger operating cost is applied to L3, R3 and M1, the average cost for the rest of the regulated customers will fall below the overall average of $81.50.

18.253 kW
5.704 kW

In setting the revenue allowance for retail operating costs, therefore, the Authority is of the view that $81.50 in 2012/13 (in 2011/12 dollars) is an efficient cost per customer when averaged across for all regulated customers, compared to the Authority's estimate of [redacted], on average, for small (less than 160 megawatt hours per annum) regulated customers. Costs associated with the acquisition and retention of contestable customers will be accounted for in Synergy's retail margin.

As with the electricity cost, the Authority recognises that a move towards this efficient level of operating cost will require a period of transition. As such, the Authority has adopted the operating cost of [redacted] per small regulated customer for 2012/13 and 2013/14 and then assumed the lower level average value of $81.50 (in 2011/12 dollars) for the following two years.

Having determined the base retail operating cost of $81.50 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.[36] Similarly, Synergy projects labour costs will account for 40 per cent of total operating costs over the review period.[37] Accordingly, the Authority has estimated

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

[37] Synergy data, SY_n3451924_v4_ERAInformation_Request_Spreadsheet_Incl_Efficiency_Gains2

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 forecast used in the mid-year review of the state budget, which is 4.25 per cent for the LPI and 2.5 per cent for the CPI, giving a result of 3.375 per cent that is used for the escalation of the retail operating cost.

4.7.1.1 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. Work undertaken by Frontier, for IPART, suggests that depreciation is in the order of $8 to $9 per customer for NSW retailers. The Authority's calculation of the depreciation cost is based on Synergy's tangible asset base, and using a straight line method, suggests that Synergy's depreciation cost is $14.10 per customer, on average over the four year review period. The significantly higher depreciation cost, compared to the typical NSW retailer is due to Synergy's recent upgrade of its IT systems, 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.

The Authority considers the depreciation cost for Synergy of $14.10 per customer, on average, over the four year review period, to be appropriate.

4.8 Draft Recommendation

6) The Authority has adopted the actual contract costs for Synergy in the first two years; being 2012/13 and 2013/14, followed by the LRMC cost approach for the following two years; 2014/15 and 2015/16.

7) The Authority has adopted the actual retail operating costs for Synergy in the first two years; being 2012/13 and 2013/14, followed by $81.50 per customer (in 2011/12 dollars for the following two years; 2014/15 and 2015/16.

8) The allowance of $81.50 per customer (in 2011/12 dollars) for retail operating costs should apply to all tariff customers, contestable and non-contestable. Additional efficient costs associated with the acquisition and retention of contestable customers are recovered through Synergy's retail margin.

9) Retail operating costs are escalated by 3.375 per cent over the review period.

10) Depreciation is separately accounted for in Synergy's cost, and the Authority considers that the average annual depreciation cost of $14.10 per customer, to be appropriate.

5 Non-Controllable Costs

There are several other types of costs over which Synergy incurs in its normal course of business operations but with little influence on these costs.

- Synergy pays network charges 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.
- There are costs associated with ancillary services, which are required to maintain Power System Security and Power System Reliability, facilitate orderly trading in electricity and to 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.
- Synergy also pays fees 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 Network Charges

5.1.1 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 were $862.472 million in 2010/11 and are budgeted at $1.094 billion in 2011/12.[38]

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 on 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. Synergy's TEC was set in 2009 at $175.7 million for 2010/11 and $181.2 million for 2011/12.[39]

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[40].

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

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

[40] Available on the Authority's website.

5.1.2 Public Submissions

Synergy

Synergy did not provide any comments on network charges in its submission.

Horizon Power

Horizon, while noting its general support for cost reflective electricity tariffs, recommended the continued provision of:

- the Tariff Adjustment Payment[41] to Horizon Power until cost reflective tariffs are reached; and
- an adequate subsidy to Horizon Power (through the TEC or CSO payments) to reflect the higher costs of providing electricity to regional areas.

Energy Supply Association of Australia (esaa)

esaa supported the transition to cost reflective electricity tariffs in both the SWIS and the NWIS. The esaa recommended the removal of the state's uniform tariff policy, and therefore the need for the tariff adjustment payments to Synergy, and the TEC payments to Horizon Power (funded by SWIS customers). The esaa submitted that where there are issues regarding capacity to pay for some customers, these should be addressed through targeted, budget funded measures.

Alinta

Alinta recommended that the TEF be funded from consolidated revenue, through a CSO payment, rather than through the TEC component of SWIS network charges. Alinta submitted that the approach to collecting the TEC is non-transparent and distorts price signals to customers away from cost reflective electricity tariffs.

5.1.3 Authority Assessment

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 network cost forecasts for Synergy to 2015/16 depend upon Synergy's volume forecasts, multiplied 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 13.

The Authority notes Western Power's network charges currently includes 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 the TEC should be funded by a CSO payment to make this cost more transparent and shared by all taxpayers in Western Australia. In calculating the efficient cost reflective level of tariffs, the Authority

[41] The tariff adjustment payment is the subsidy paid to Synergy, in the form of a CSO payment, cover the difference between uniform tariffs on the SWIS and their cost reflective levels as determined by the Office of Energy in 2009, in the glide path towards cost reflective tariffs.

has assumed that the 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. 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.

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 TEC on a typical household's annual electricity bill has increased from $35 in 2006/07 to $83 in 2011/12.

The Authority notes Western Power's proposed third Access Arrangement has included a total TEC amount close to $1 billion dollars (nominal), or $200 million per annum over the five year period from 2012/13 to 2016/17. Only a proportion of the TEC is charged to Synergy 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 12 below.

Table 12 TEC Attributable to Synergy's Tariff Customers ($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 of 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.

Table 13 Synergy's Total Tariff Forecast Network Costs 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Volume (GWh)	7,938 28.6 PJ	7,860 28.3 PJ	7,820 28.2 PJ	7,820 28.2 PJ
Network Charges (c/kWh)	@906 MW	@897 MW	@892 MW	@892 MW
- TEC exclusive	8.86 $24.61	9.04 $25.11	9.27 $25.75	9.56 $26.56
- TEC inclusive	10.44 $29.00	10.66 $29.61	10.93 $30.36	11.26 $31.28
Network Costs ($m)				
- TEC exclusive	703.1	710.5	724.7	745.7
- TEC inclusive	828.6	837.5	854.4	878.9

Source: ERA Analysis

5.1.4 Draft Recommendation

11) The Authority recommends that the TEC be removed from Western Power's Network Charges and be funded by a CSO from the consolidated revenue.

5.2 Ancillary Services Costs

Ancillary services are necessary to maintain the balance between supply and demand, system security and system frequency. As a registered market customer in the wholesale electricity market 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 14 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 14 Actual and Forecast Ancillary Services Costs Paid by Synergy 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.

5.2.1 Authority Assessment

The Authority has reviewed the information provided by Synergy and notes the following:

- The Authority is aware of the increases in the cost associated with load following ancillary service in the market over recent years. For instance, the cost of load following ancillary service 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.[42] The cost of load following ancillary service is dependent on the generation capacity required for providing the service and the real time balancing price during the trading intervals. The Authority recognises further cost increase is likely in 2011/12 due to the commissioning of the Collgar wind farm (206 MW) in October 2011 in order to meet the SWIS Operating Standards as defined in the Market Rules. The load following capacity requirement for 2011/12 as determined

[42] System Management Ancillary Service Report 2011.

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.

- 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 there will be further cost increases with regard to spinning reserve service cost.
- 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.
- The Authority expects that costs associated with dispatch support will also increase from 1 July 2012 with the introduction of the carbon pricing regime.

The Authority considers that Synergy's forecast ancillary service costs are reasonable based on information received so far.

5.2.2 Draft Recommendation

12) 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.

5.3 Market Fees

5.3.1 Background

As a participant in the wholesale energy market, Synergy is required to pay market fees to the IMO to cover of 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, based on 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 on the WEM for the year.

$0.154 /GJ

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 trading volume of GWh.[43] The total fee comprises: 138.1PJ @ 4.38 GW

- IMO Market Fee — $0.327 per MWh; $0.0908 /GJ
- System Management Fee — $0.195 per MWh; and $0.0542 /GJ
- Economic Regulation Authority Fee — $0.034 per MWh. $0.0094 /GJ

[43] IMO website.

$0.0908 GJ

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. $0.0092 /GJ

5.3.2 Synergy's Market Fees

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.[44] 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.
$0.130 /GJ

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

Table 15 Actual and Forecast Market Fees Paid by Synergy 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

5.3.3 Authority Assessment

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, covering 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, 25 per cent higher compared to 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. $0.153 /GJ $0.154 /GJ

The Authority has examined some relevant information provided by Synergy so far and noted Synergy expected a reduction of 3.3 per cent in 2011/12 in its sales volume compared to the 2010/11 level. Based on Synergy's sale volume projection for 2011/12 and the published market fee rate, the Authority's calculation has shown 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.

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

5.3.4 Draft Recommendation

13) 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 it is appropriate for Synergy to recover the payment in full from its customers.

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 cost. 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. Synergy has adopted a separate retail margin for contestable and non-contestable customers, based on interstate benchmarking, to differentiate between the risks of a contestable tariff portfolio and a non-contestable portfolio.

The equivalent to a retail margin (expressed as a percentage) in the case of an electricity network is the rate of return, or the weighted average cost of capital (WACC). A rate of return is determined as the product between the WACC 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 Public Submissions

In the issues paper, the Authority invited comments on what issues and risks should be taken into account when determining an efficient retail margin for Synergy.

Synergy

Synergy submitted that it measures its retail margin as revenues minus the costs of energy purchase, network charges and retail operating costs, but before deducting charges for finance costs, depreciation or bad debts.

Synergy noted that an efficient retail margin was required to provide an adequate return on long term capital investments, to compensate investors for the systematic risks faced by the business. Synergy listed these risks as:

- volume risk (when the actual quantum or profile of load differ from those assumed when setting regulated tariffs);
- energy purchase risk (when wholesale spot or contract electricity prices differ from the energy purchase costs assumed when setting tariffs, due to changes in economic conditions or demand); and

- market and general external business risks (due to changes in global and state economic conditions, including interest rates, exchange rates, payment default).

Synergy submitted that it was particularly exposed to volume risk, due to changes in its customers' energy usage, and the ability of its contract and contestable customers to switch to other retailers. Energy purchase risk was also significant, due to differences between the long-term supply contract prices and short term sales contract prices, which fluctuate with market demand.

Horizon Power

Horizon Power submitted that Synergy's retail margin needs to reflect the systematic risks faced by Synergy's shareholder, the Western Australian government. These risks are due to volatility in the global economy, the availability and price of fuel for electricity generation and the WEM, as the market rules continue to evolve.

Horizon Power noted that these risks could be ameliorated through improved stability in the energy sector (through planning, policy, fuel costs and availability).

These risks could also be ameliorated through the use a combination of solar and wind power

Energy Supply Association of Australia (esaa)

ESAA recommended that the Authority's recommended tariffs include an appropriate retail margin, commensurate with the risks faced by a retail business.

Alinta Energy

Alinta supported the approach of setting a retail margin for Synergy based on the estimated profitability under a competitive retail market. Alinta recommended that the Authority draw on work by regulators in other jurisdictions in setting retail margins for similar electricity retail businesses.

Alinta submitted that in determining the different risks associated with retailing to contestable and non-contestable customers, the Authority should take care to ensure that the risks being compensated were purely systematic risks. For example, costs such as those associated with the acquisition and retention of contestable customers are more appropriately considered as part of retail operating costs.

6.3 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 16 below:

Table 16 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 16 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.

Another issue is that the effect of annual changes in the cost base that the above percentages are applied is unclear. Such changes will lead to a different retail margin (in terms of a dollar value) which may over or under compensate for the capital invested in the business. This is only an issue if investment does not move broadly in the same direction and magnitude as total cost, which is expected to be the case for a retail business that has a small tangible asset base.

6.4 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 customers may decrease. This risk will be compensated via the retail margin because the risk arises from the exposure to the overall economic conditions.

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 16.

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 – 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 investment in the retail business are set out in the following sections.

6.4.1 Rate of return

The rate of return that any business should earn relates to the riskiness of the business. To capture this relationship, a well accepted finance model has been utilised unanimously by Australian Regulators. This is the Capital Asset Pricing Model (CAPM).[45] This finance model is applied for the purpose of deriving the risk-adjusted return for Synergy.

A detailed discussion on the calculation of the risk-adjusted return for Synergy is included in Appendix E.

The key difference between the rate of return for Synergy and the rate of return for Western Power is that Synergy is not exposed to financial risk as its gearing level is effectively zero. Gearing refers to the proportions of the value of the regulated business assumed to be financed by debt and equity. The relative proportions of debt and equity that a firm has outstanding constitute its capital structure. The capital structure choices differ across industries, as well as for different companies within the same industry.

> The WACC that has been calculated for Synergy reflects only the cost of equity rather than a weighted average of the costs of equity and debt. The Authority considers that both Synergy and Western Power should have the same level of risk when assessed against the total market risk. (This is known as a 'systematic risk'.) As such, the asset beta for both companies should be the same. However, Synergy has zero debt. Although this difference in the capital structure may have some implications for Synergy's cost of capital, it is unlikely to be significant enough to make a material difference.[46] As such, the cost of capital adopted for Synergy is the same as that of Western Power.

For this draft report, the nominal pre-tax rate of return is calculated to be 7.40 per cent as at 29 February 2012. This return of 7.40 per cent is applied to the estimates of the asset value for Synergy to reflect the dollar value of the retail margin. The following section determines the estimation of the asset value for Synergy.

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[45] 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.

[46] See Appendix E for a detailed discussion on Synergy's cost of capital calculation.

6.4.2 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 consensus 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.

6.4.3 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 17 below adopts a total asset base approach, based on the cost of acquiring a comparable business.

Table 17 Cost of Acquiring a Business, Total Asset Base ($) 2011/12 to 2015/16

	2011/12	2012/13	2013/14	2014/15	2015/16
Customer Based Method	1,004,118,916	1,026,352,338	1,051,049,780	1,073,081,319	1,092,584,007
MWh Based Method	790,790,393	811,003,330	826,877,607	844,629,721	862,166,176
Average of Two Methods	897,454,654	918,677,834	938,963,694	958,855,520	977,375,092

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 7.4 per cent, the results shown in Table 18 were attained:

Table 18 Estimated Regulatory Asset Base and Associated Retail Margin 2011/12 to 2015/16

	2011/12	2012/13	2013/14	2014/15	2015/16
Total Asset Value	897,454,654	918,677,834	938,963,694	958,855,520	977,375,092
Retail Margin	66,411,644	67,982,160	69,483,313	70,955,308	72,325,757

Source: ERA Analysis

The dollar value of the retail margin for Synergy is in the range of $60 million to $72 million per year when the cost of acquiring the business is considered. This equates to approximately 3.4 per cent to 3.6 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.

6.4.4 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 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 19 below.

Table 19 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

Sources:

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

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

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

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

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

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 at which point estimate of a CARC reflect a reasonable view of a CARC 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 considers the CARC approach is more reasonable, given the circularity inherent in a method based on the cost of acquiring a business. On that basis, the Authority concludes that an annual CARC of $40 per customer for Synergy is appropriate and this estimate of CARC is adopted in the estimate of Synergy’s regulated asset base.

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. The Authority also considers that further work may be required in the final determination to reappraise the estimate of Synergy’s working capital used in this draft report.

Based on information provided by Synergy, the estimated regulatory asset base using the cost of acquiring and retaining customers is presented in Table 20 below.

Table 20 Estimated Value of Synergy's Regulated Asset Base (Tangible Asset Values, $m) 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Fixed Investment	30,939,679	23,666,341	13,719,593	6,371,902
Working Capital	235,218,219	245,114,187	267,749,244	277,172,708
CARC[47]	539,956,009	551,974,075	565,324,043	577,232,983
Total	**806,113,906**	**820,754,602**	**846,792,880**	**860,777,593**

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

Using the above regulatory asset base and the forecast number of customers, the asset base per customer (i.e. the value per customer) is approximately $800.

[47] 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 21 Estimated Regulatory Asset Base and Associated Retail Margin ($) 2012/13 to 2015/16

	2012/13	2013/14	2014/15	2015/16
Total Asset Value	806,113,906	820,754,602	846,792,880	860,777,593
Retail Margin	59,652,429	60,735,841	62,662,673	63,697,542

Source: ERA Analysis

The dollar value of the retail margin for Synergy is in the range of $58 million to $64 million per year when CARC methodology for valuing the intangible asset is considered, as shown in Table 21 above. This equates to approximately 3.1 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.

6.5 Authority's Assessment

On the issue of differential margins for contestable and non-contestable customers, the Authority does not consider Synergy's contestable and non-contestable operations to have different levels of risk, and consequently does not consider it appropriate to adopt separate retail margins for contestable and non-contestable customers. The principle applied when setting regulated tariffs is to achieve the same outcome as would apply if markets were fully competitive. 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 is largely inconsistent with regulatory decisions in other jurisdictions.

Given that the Authority rejects the application of different margins to different customer categories, the Authority converted Synergy's proposed dual margins of 3.4 per cent applied to the total cost for non-contestable customers, and 5 per cent applied to the total cost for contestable customers, to a single weighted average margin of 3.6 per cent to all customers.

The Authority tested this single weighted average of 3.6 per cent against various alternatives, including benchmarking and bottom-up approach, as described earlier.

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 used indicate a range of 3.1 per cent to 3.6 per cent.

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

The view is based on the following considerations:

- the benchmarking approach is a circular approach as regulators tend to base their decisions on 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 3.4 per cent and 3.6 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 is also imprecise, as Synergy's CARC falls within a wide range, being between $30 and $50. This method returns a range from 3.1 per cent to 3.4 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.

Draft Finding

14) 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 2.2.2, moving towards cost reflective tariffs is necessary to develop a competitive electricity retail market in Western Australia and to send appropriate price signals to customers regarding their electricity usage.

To be cost reflective, a retail tariff has to reflect not only the overall cost of supplying electricity, but also how the cost to supply electricity varies with the quantity of energy demanded, e.g. the cost to supply electricity will increase in times of peak demand. Therefore, to determine fully cost reflective tariffs both the level of the overall tariff and 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, with reference to the competitive nature of the market. 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 Cost Reflective Tariffs

7.2.1 Background

This section details Synergy's cost reflective tariffs on an average revenue (c/kWh) basis. The Authority has not attempted 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 are presented with the impact of the Tariff Equalisation Contribution (TEC, the component of the network charge to compensate Horizon Power for its shortfall in revenue under the State's uniform tariff policy) excluded. The Authority believes that SWIS customers should not subsidise Horizon Power customers and that any shortfall in revenue to Horizon Power from the Uniform Tariff Policy should be funded from consolidated revenue. However, if the TEC is to be funded through SWIS network tariffs, SWIS customers should be aware of the amount that their bill must rise over and above the actual costs that they incur.

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)[48].

The cost reflective level of tariffs on a per kWh basis for Synergy's total tariff business is shown in Table 22 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 22 Cost Reflective Tariff Breakdown, Total Tariffs (c/kWh, nominal) TEC Excluded 2012/13 to 2015/16

c/kWh	2011/12	2012/13	2013/14	2014/15	2015/16
Wholesale Electricity Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Networks	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Retail Operating Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Renewable Energy Certificates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Carbon	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Market Fees	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Retail Margin	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: ERA Analysis

7.2.2 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.

7.2.2.1 Allocation of Energy Costs

The Authority considered the following approaches when allocating Synergy's energy'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.[49] 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

[48] 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.

[49] 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)

group's consumption pattern is also summarised into the three time-of-use 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.

- **Long Run Marginal Cost (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 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. The Authority engaged consultant Marsden Jacob Associates (MJA) to construct a model that simulates the optimal dispatching of Synergy's contract portfolio and calculates the least cost outcome for each half hourly interval based on Synergy's total load profile. These 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.

The Authority has therefore adopted the time-of-use average price approach. For years when Synergy's estimated dispatch costs are used, the Authority engaged consultant Marsden Jacob Associates (MJA) to construct a model that simulates the optimal dispatching of Synergy's contract portfolio and calculates the least cost outcome for each half hourly interval based on Synergy's total load profile. These 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.

7.2.2.2 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 reserve capacity mechanism (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.[50]

For the purpose of capacity allocation, Synergy applies a two-step approach. Firstly Synergy calculates the peak demand for each customer group based on the relevant energy consumption forecast, and on the peak load ratios derived from actual or deemed load profiles. Secondly, the aggregate of the peak demand across the customer groups is compared with Synergy's total capacity obligation forecast, based on its expected share of the capacity requirement set by the IMO. Any difference is then allocated across the customer groups as Synergy determines to be appropriate.

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 and the demand for each customer group that half-hour interval. Each customer group's contribution is calculated as a percentage of the peak demand of the total load profile. This contribution is used to allocated Synergy's forecast capacity obligation and any related costs of meeting the capacity obligation. These include the costs associated with contracted capacity in the contract portfolio and capacity purchased from the IMO.

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

Time of use is a method of trying to minimise variation from the long term average. It would be better to use a more direct method. Measure the long term average consumption (Watts) for that customer. The instantaneous power is calculated in the power meter once per second. This power is charged at a base load $/GJ. When power demand exceeds the average then the differential power is added to the last measurement. This total energy value is charged at a much higher $/GJ to encourage the spreading of the power consumption. Remember that Energy (Joule) = Voltage x current x time where time is 1.

[50] DAA 2009 study.

Table 23 Synergy's Capacity Allocation as Determined by the Authority for 2012/13

	Total Allocated Capacity (MW)	Total Allocated Capacity (%)	Total Cost
Non-Contestable Customers			
A1	2162	53%	$ 382,189,785
SM	73	2%	$ 12,936,187
B1	0	0%	$ 81,585
C1	13	0%	$ 2,375,310
D1	3	0%	$ 611,286
K1	42	1%	$ 7,505,663
L1	295	7%	$ 52,127,418
R1	44	1%	$ 7,769,601
Z1	23	1%	$ 4,105,124
UMS	11	<1%	$ 1,897,338
Contestable Customers			
L3	155	4%	$ 27,464,468
M1	3	<1%	$ 575,596
R3	176	4%	$ 31,154,810
S1	103	3%	$ 18,261,612
T1	76	2%	$ 13,499,157
ECON	722	18%	$ 127,705,720
PP	185	5%	$ 32,723,530
Total Synergy	**4089**	**100%**	**$ 722,984,189**

7.2.2.3 Allocation of Network Costs

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

7.2.3 Cost Reflective Tariffs

Once network, energy and capacity costs have been allocated to each tariff category, the cost reflective level of each tariff can be calculated.

Table 24 below shows the cost reflective level for each of Synergy's regulated tariffs, as well as for the Z1 tariff.[51]

[51] This is calculated as a by-product of calculating the regulated tariffs.

Table 24 Cost Reflective Tariffs, Individual Tariffs (c/kWh, nominal) TEC Exclusive 2012/13 to 2015/16

Tariff	Tariff Description	2011/12 Actual	2012/13 Cost Reflective	2013/14 Cost Reflective	2014/15 Cost Reflective	2015/16 Cost Reflective
	Non-contestable					
A1	Residential	22.34	27.50	27.62	26.81	28.08
B1	Residential water heating	14.25	18.22	18.75	19.05	19.77
C1	Non-profit organisations	22.26	24.40	24.52	23.73	24.80
D1	Charitable residential	18.79	23.74	24.01	23.13	24.80
K1	Mixed commercial & residential	23.75	26.65	26.78	26.27	27.37
L1	Low voltage supply (<50 MWh)	24.02	27.01	27.10	26.49	27.63
R1	Time-of-use tariff (<50 MWh)	17.37	25.12	25.26	24.50	25.65
W1	Traffic lights	22.91	24.49	24.61	22.77	24.04
Z1	Street lights	36.50	35.90	38.47	39.05	40.26
UMS	Unmetered supply	22.91	23.57	23.68	21.99	23.22
	Contestable					
L3	Low voltage supply (>50 MWh)	29.04	26.44	27.45	29.80	35.04
M1	General supply (high voltage)	25.21	25.60	26.71	26.00	26.88
R3	Time-of-use tariff (>50 MWh)	23.25	21.09	21.16	20.67	21.70
S1	Low/med voltage time-of-use	19.33	21.13	21.11	20.11	21.09
T1	High voltage time-of-use	18.56	19.82	19.84	18.94	19.87
	Average across all tariffs	**22.93**	**26.55**	**26.71**	**26.00**	**27.26**

Source: ERA Analysis

Table 25 shows the differences (in c/kWh) between the assumed 2012/13 State Budget tariffs (being 5% plus carbon pass through) and the cost reflective tariffs in the same year. The cost reflective tariffs exclude the TEC. Adding back in the TEC would increase the cost reflective tariffs by an average of approximately 1.64 c/kWh. $4.56 /GJ

$/GJ

Table 25 Assumed Budgeted Tariffs versus Cost Reflective Tariffs (c/kWh) TEC Exclusive 2012/13

		2012/13	2012/13	
		Assumed Budgeted Tariff	**Cost Reflective Tariff**	**Difference**
	Non-Contestable			
A1	Residential	$70.36	$76.39	-$6.03
B1	Residential water heating	$46.75	$50.61	-$3.86
C1	Non-profit organisations	$70.11	$67.78	$2.33
D1	Charitable residential	$60.03	$65.94	-$5.92
K1	Mixed commercial & residential	$74.47	$74.03	$0.44
L1	Low voltage supply (<50 MWh)	$75.25	$75.03	$0.22
R1	Time-of-use tariff (<50 MWh)	$55.86	$69.78	-$13.92
W1	Traffic lights	$74.64	$68.03	$6.61
Z1	Street lights	$101.83	$99.72	$2.11
UMS	Unmetered supply	$72.03	$65.47	$6.56
	Contestable			
L3	Low voltage supply (>50 MWh)	$91.28	$73.44	$17.83
M1	General supply (high voltage)	$77.47	$71.11	$6.36
R3	Time-of-use tariff (>50 MWh)	$71.64	$58.58	$13.06
S1	Low/med voltage time-of-use	$60.97	$58.69	$2.28
T1	High voltage time-of-use	$59.39	$55.06	$4.33

Source: ERA Analysis

Overall, Synergy's estimated 2012/13 tariffs are 2.8 per cent below their aggregated cost-reflective level. However, there is substantial variation between tariffs. Generally speaking, on a TEC exclusive basis, contestable tariffs are above their respective cost-reflective levels, while non-contestable tariffs are below cost. Adding back in the effect of the TEC would, on average, almost eliminate the difference between the estimated actual tariffs and cost reflective tariffs for contestable customers, although 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.

7.3 Amalgamation of Tariffs

7.3.1 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
1.825 kW 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 C1 tariff is that it may contain a subsidy, distorting market signals for efficient resource allocation. It may be better to provide direct a 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
13.97 kW 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.

7.3.2 Public Submissions

In the issues paper, the Authority asked for comments as to whether any of the tariffs on the current list of tariffs could be amalgamated, and why. Further, the Authority asked whether there are benefits to having fewer uniform tariffs.

Synergy

Synergy does not support the elimination or amalgamation of any of the current tariffs, with the exception of the following tariffs:

- B1 (off-peak water heating tariff for residential customers heating water between 11pm and 6am) – Synergy submitted that this tariff dates back to the 1970s and applies to a small number of customers (around 500), all of whom are also on the A1 tariff. Two separate meters are required for customers on both the A1 and B1 tariff. Synergy no longer promotes this tariff to new customers and recommends that existing B1 customers be offered either the A1 tariff or SmartPower, a residential time-of-use tariff[52].
- C1 (special community service tariff for voluntary, non-profit organisations) and D1 (special tariffs for charitable of benevolent organisations providing residential accommodation) – Synergy noted that the Office of Energy had previously recommended that these tariffs be replaced by a government funded CSO paid directly to the organisations. Customers could then be supplied under existing tariffs, such as L1/L3 or R1/R3. Synergy submitted that this would eliminate the costs to Synergy of assessing and administering these tariffs. However, Synergy further submitted that if the current arrangements were less costly to administer than alternative arrangements, the tariffs should not be abolished.

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.

Horizon Power supported simplicity and transparency in tariff structures. Horizon Power noted that it had small numbers of customers on the C1 and D1 tariffs (charitable organisations) and the N and P tariffs (federal and government institutions, and supported transferring these customers to the L and M tariff classes (general supply). Horizon Power submitted that having fewer tariff classes would reduce the costs of billing and administration. Horizon Power also supported the provision of direct CSOs to charitable organisations, rather the distorting price signals away from cost reflective tariffs.

7.3.3 Authority Assessment

7.3.3.1 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.

Synergy has not provided any information to the Authority as to the size of any investment required to upgrade its billing and information systems ensuring compliance (or on any other additional administrative costs of maintaining the B1 tariff) . As such, the Authority is unable to assess the financial impact of continuing to offer the B1 tariff.

52 SmartPower is a non-gazetted optional residential pricing arrangement that has a fixed component, time-of-use component (peak, weekday shoulder, weekend shoulder, off-peak), and a seasonal component (summer, winter)

If the B1 tariff moves to a cost reflective level (and in the absence of information from Synergy regarding potential costs to improve their billing processes), there is no evidence to suggest that there is a net benefit in merging B1 tariff with A1 tariff**.**

7.3.3.2 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 which is significantly less than either the L1 or L3 tariff. The D1 tariff is has an estimated cost profile lower than that of R1 and higher than that of R3.

It is noted that the Recommendation 4 of the Office of Energy'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 of, 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.

7.4 Draft Recommendation

15) The Authority considers that there is no justification for merging any 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. (Terms of Reference 1-3).

The Terms of Reference do not require the Authority to address equity issues which 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 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 Public Submissions

Horizon Power

Horizon Power recommends that any price increases be phased in gradually to limit potential price shocks to customers. Horizon Power also supported the provision of direct subsidies to customers facing financial hardship, rather than distorting prices away from the true cost of supplying electricity.

Western Australian Council of Social Service (WACOSS)

WACOSS is concerned with the well-being of low income and disadvantaged customers, and the way in which energy prices affect these customers' cost of living and quality of life. WACOSS noted a range of factors which contribute to the capacity of customers to pay, such as income, employment level, household size, the time and hours of the day when household members are at home, health, special needs and financial hardship. WACOSS recommended that the Authority take these factors into account when considering the equity of tariffs, and carefully consider the scope, nature and targeting of consumer concessions.

Energy Supply Association of Australia (esaa)

esaa recommended that social welfare outcomes be decoupled from energy prices. esaa submitted that setting tariffs below cost reflective levels was a blunt measure for directing subsidies to customers who need assistance, as the discounts apply to all customers. esaa supported the transitioning of energy prices to cost reflective levels for both the SWIS and the NWIS, and the removal of the uniform tariff policy. esaa submitted that customers who do not have the capacity to pay cost reflective prices be supported by purposely designed, budget funded measures.

8.2 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 position of the Council of Australian Governments (COAG), and the Ministerial Council on Energy[53], which 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[54] that do not materially impede competition.

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.

8.3 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.

[53] http://www.coag.gov.au/coag_meeting_outcomes/2009-07-02/docs/energy_market_agreement.pdf

[54] 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.

8.3.1 Residential Customers

8.3.1.1 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 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 26 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:

- 2011/12 based on current tariffs
- 2012/13 based on an assumed increase in existing tariffs as published in last year's State Budget Papers of 5 per cent, plus full cost of carbon pricing being 8.4 per cent.
- 2013/14, 2014/2015 and 2015/16 transition to estimated cost reflective tariffs (including carbon pricing) on a straight line basis
- Average annual consumption of 708 W
- 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 they do now. 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. Including the TEC increases cost reflective tariffs, and therefore the cost reflective bill.

Table 26 Bill Impacts: Estimated Cost Reflective Bills, TEC Exclusive 2011/12 to 2015/16

		Actual	Forecasts			
	Tariff (GST inclusive)	**2011/12** **Average Bill**	**2012/13** **(+ 5% and carbon pricing)**	**2013/14** **Cost Reflective**	**2014/15** **Cost Reflective**	**2015/16** **Cost Reflective**
A1	Residential	1,525	1,729	1,878	1,886	1,917
	Change		204	60	63	65

Source: ERA Analysis

The estimated average bill impact from moving from existing A1 residential tariffs to cost reflective tariffs in 2015/16 is approximately 28 per cent over 4 years. After the initial increase of around $200, yearly increases thereafter will then be in the order of $60.

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.

8.4 Impacts on Synergy and Government

8.4.1 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 outside 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.

8.4.2 Synergy's Revenue Requirement

Synergy's efficient revenue requirement is shown in Table 27 below on a TEC exclusive basis.

Table 27 Synergy's Efficient Revenue Requirement ($m, nominal) 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					
Depreciation					
Retail Margin					
Total					

Source: ERA Analysis

In order to implement cost reflective tariffs, by 2015/16 Synergy needs to reduce its energy purchase costs, including carbon, by [redacted] in 2014/15, and its retail operating costs by [redacted]. This will have a small impact on the dollar value of the retail margin, as the retail margin is calculated as a percentage of the total cost. For comparison, Synergy's revenue requirement based on actual projected costs is given below in Table 28. The difference between this and the revenue requirement based on the efficient costs (as presented in Table 27 above) are shown in Table 29.

Table 28 Synergy's Revenue Requirement Based on Actual Projected Costs ($, nominal) 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					
Depreciation					
Retail Margin					
Total					

Source: ERA Analysis

Table 29 Differences Between Synergy's Efficient Revenue Requirement and Actual Revenue Requirement ($m, nominal) 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					
Depreciation					
Retail Margin					
Total					

Source: ERA Analysis

Given that the Authority recommends Synergy reach cost reflectivity based on LRMC by 2014/15, two years is considered a sufficient period to implement these efficiency gains.

8.4.3 Impacts on Government

Table 30 shows that, in the first two years, under Synergy's submitted costs and excluding the TEC, Synergy would either cover or almost cover its costs excluding its retail margin. There would be, however virtually no return to the shareholder (Government) from running this business because the Government would be paying the CSO to cover the costs of implementation.

Significant investment in solar/wind in not only Horizon Power areas but at the outer extremities of the SWIS should be able to reduce the CSOs. CSOs are higher than necessary because the purchase of diesel and its transport over long distances along with poor distribution efficiency in the SWIS.

Although the actual CSO would depend on the way the Government intends to achieve cost reflective tariffs, for the purposes of calculating the CSO in the following table, it is assumed that a smooth transition (that is, an equal percentage increase in each of the three years following 2012/13) towards cost reflectivity in 2015/16 is implemented. This is referred to as a 'glide path'.

Table 30 Synergy's Estimated Glide Path CSO, Tax and Dividends ($m, nominal) 2012/13 to 2015/16 , Excluding TEC

	2012/13	2013/14	2014/15	2015/16
Glide Path CSO	59.5	39.6	-51.1	-
Profit Including Glide Path CSO	71.9	67.2	70.3	72.2
Tax Equivalent Payment	30.8	28.8	30.1	30.9
Dividends	54.0	50.4	52.7	54.2

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 a CSO to cover the TEC. This is shown in Table 31 below.

Table 31 Additional CSO required to fund TEC ($m nominal) 2011/12 to 2016/17

2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
181.2	186.6	190.8	195.7	201.5	207.5

Source: ERA Analysis

Should the TEC be retained in distribution network charges, this would amount to approximately 1.58 c/kWh (nominal) in 2015/16 or approximately $97.83 on an average (A1) residential electricity bill.[i] $4.39

The assumed tariff increases in 2012/13 and the Authority's recommended cost reductions have the impact of lessening the financial loss to Government from Synergy's regulated business.

Currently, the Government compensates Synergy for the difference between cost reflective tariffs and actual revenue earned by Synergy. This payment is called the Tariff Adjustment Payment. If Synergy were to charge cost reflective tariffs, the Tariff Adjustment Payment would be zero. In 2011/12, the Tariff Adjustment Payment[55] from the Government to Synergy was $349.6 million[56]. The TEC in this year was $181.2 million, of which approximately $129 million can be attributed to Synergy tariff customers.[57]

The table below shows the net impact on government of moving to cost reflective tariffs in combination with the TEC being funded via a CSO. In 2015/16, the CSO would reflect the full TEC amount of $201.5 million. The $201.5 million cost to Government in 2015/16 will be offset to some extent by dividends of $54.2 million and tax equivalent payments of $30.9 million.

55 The CSO paid by the Government to Synergy to compensate it for retail tariffs being lower than Synergy's costs

56 2011/12 Budget Paper No. 3, p293

57 The TEC also applies to Synergy's market-based (or non-tariff) customers, which the Authority assumes to be operating at cost-reflective levels, and non-Synergy network users. The shortfall between the data in Table 4 and the forecast annual TEC amount is currently funded by these customers.

Table 32 Impact on Government ($m, nominal)

	2011/12	2012/13	2013/14	2014/15	2015/16
Tariff Adjustment Payment	-349.63	-59.55	-39.58	51.05	-
CSO income due to removal of TEC		-186.6	-190.80	-195.70	-201.50
Total Government Impact	**-349.63**	**-246.15**	**-230.38**	**-144.65**	**-201.50**

Source: ERA Analysis

Draft Recommendation

Synergy

16) The Authority considers two years to be an appropriate period for Synergy to achieve the efficiency gains necessary to move to cost reflective tariffs.

17) The Authority recommends that Synergy take steps to reduce wholesale electricity costs and retail operating costs over this two year period.

Government

18) 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.

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 9.3 sets out the Authority's assessment and recommendations on how cost reflective tariffs should be monitored and reviewed.

9.2 Removal of Regulated Tariffs for Contestable Customers

9.2.1 Background

All electricity customers connected to the South West Interconnected System (SWIS) who consume more than 50 MWh per annum (an average of 5.708 kW)at an electricity supply address have a choice of electricity retailer.[58]

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".

9.2.2 Current Tariffs for Contestable customers

The following tariffs are currently available for customers who consume greater than 50 MWh per annum:

[58] 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.

- 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.

[redacted]

Table 33 Average Consumption in 2010/11 for L3 and R3 Customers

Tariff	No. Customers	Average Consumption 2011 (MWh)
L3	[redacted]	[redacted]
R3	[redacted]	[redacted]

Source: Synergy.

Note: Customer numbers and consumption are based on an average across the financial year and may not match year end data.

[redacted]

Table 34 Average Consumption in 2010/11 for M1, S1 and T1 Customers

Tariff	No. Customers 2010/11	Average Consumption 2011 (MWh)
M1 (high voltage)	[redacted]	[redacted]
S1 (low voltage)	[redacted]	[redacted]
T1 (high voltage)	[redacted]	[redacted]

Source: Synergy

Note: Customer numbers and consumption are based on an average across the financial year and may not match year end data.

9.2.3 Public Submissions

In the issues paper, the Authority asked for comments on whether the uniform tariffs, which are currently subsidised from cost reflective levels, should continue to be available to large, contestable business customers, or whether these should be phased out.

Synergy

Synergy submitted that it was important for all tariffs for contestable customers to be set on a cost reflective basis, including an appropriate retail margin. The competitive retail market will drive the contracts that are offered to contestable customers.

Synergy submitted that contestable customers should continue to have the option of the uniform tariff. Synergy noted that requiring contestable customers to move to market-based contracts would involve costs to customers and to Western Power, such as the installation and management of time-of-use meters.

Horizon Power

Horizon Power supported cost reflective tariffs for commercial customers in principle, but noted that small business customers in regional areas (those on Horizon Power's L2 and L4 tariffs)[59] were already facing financial pressures due to increases in uniform tariffs. Horizon Power submitted that if cost reflective pricing were to further raise uniform tariffs, such businesses would face additional stress and could potentially close or relocate.

Horizon Power indicated that it may need to offer an alternative pricing plan to a cost reflective uniform tariff. This approach would involve administrative costs to Horizon Power, associated with communicating with customers, and understanding the impacts on revenues and cash flows due to customers switching away from the uniform tariff.

Electricity Supply Association of Australia (esaa)

esaa supported the transition towards cost reflective retail tariffs. However, it noted electricity tariffs remain below the cost of supply, with the shortfall funded by Government through the tariff adjustment payment to Synergy. esaa submitted that these payments are available to contestable business customers (in addition to non-contestable residential and business customers) and therefore create a barrier to competition.

esaa firmly supported the establishment of full retail competition and the removal of retail price regulation. However, esaa recommended a number of reforms that must be implemented first, including independent price regulation through a transparent and consultative process and the establishment of cost reflective pricing.

Alinta Energy

Alinta supported the transitioning of tariffs for contestable business customers (using more than 50MWh per year) to fully cost reflective tariffs as soon as practical. Alinta submitted that there were no reasons for continued subsidisation of these customers. Further, competitive markets provided the best outcomes for consumers and businesses in the long term, so the sooner the transition, the better.

Chamber of Commerce and Industry (CCI)

CCI strongly supported the phasing out of uniform tariffs for large contestable business customers as a step towards a more competitive retail market. CCI advocated fully cost reflective retail tariffs, full retail contestability and, ultimately, the deregulation of the retail market.

[59] The L2 tariff for Horizon Power customers is the equivalent of the L1 Synergy tariff category (low/medium voltage general supply for customers using less than 50 MWh per year), while the L4 Horizon Power tariff is equivalent to the L3 Synergy tariff category ((low/medium voltage general supply for customers using more than 50 MWh per year).

How Contestable is the Retail Market?

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.

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[60] stated 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.[61]

Ability of Customers to Negotiate a Fair Contract

- M1, S1, T1 tariff customers – these customers are very large and should have both the ability and market power to negotiate a reasonable market based contract, although some will experience price increases.

- L3 and R3 tariffs – 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.

This is demonstrated in Table 35 below, which consolidates all small contestable customers and all large contestable customers to show the average current tariffs and cost reflective levels in 2012/13:

Table 35 Average Current Tariffs and Cost Reflective Levels in 2012/13 (c/kwh)

	Current Tariffs (11/12)	Cost reflective levels (12/13)	Cost reflective levels (12/13) (TEC incl.)
Small Contestable	25.96	23.49	25.18
Large Contestable	19.02	20.55	22.28

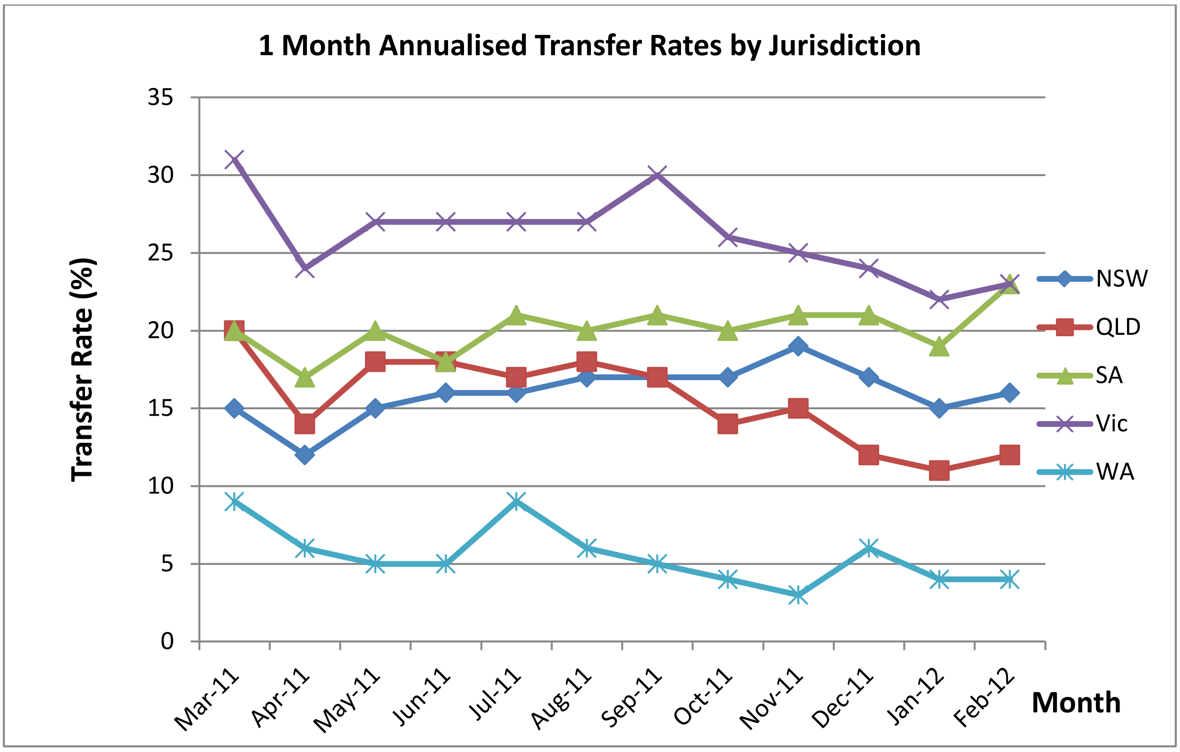
Source: ERA Analysis

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.

[60] Office of Energy (August 2009), *Verve Energy Review*.

[61] Synergy Annual Report 2010/11, p2.

Figure 7 1 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.

9.2.4 Authority Assessment

The Authority believes that, given the tariffs for contestable customers have only recently reached 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.

However, the Authority considers that effectiveness of competition is re-assessed again at the next review.

Draft Recommendation

19) The Authority recommends that regulated tariffs be retained for all contestable customers through to 2015/16 and re-assessed at the next review.

9.3 Regulatory Arrangements

9.3.1 Public Submissions

In the issues paper, the Authority invited comments on how often cost reflective tariffs should be determined for Synergy.

Synergy

Synergy submitted that:[62]

> The frequency of tariff determinations should balance the requirements for:
>
> - certainty for customers and other industry participants with regard to future prices;
> - effective risk mitigation for Synergy and customers; and
> - administrative simplicity.

Synergy noted that these objectives could be inconsistent (e.g. the need to set prices for a reasonably long period to provide price certainty could conflict with the need to vary prices in response to short-term changes in costs or market conditions, to provide for effective risk mitigation and promote retail competition).

Synergy supported the framework applied by the NSW regulator, IPART, in which retail electricity charges were determined for a three year period to cover an allowance for retail operating costs and a fixed retail margin. The methodology includes annual reviews of the energy cost allowance and other specified input assumptions; a review of the impact on energy costs of carbon pricing; and the pass-through of efficient costs associated with regulatory or taxation changes.

Horizon Power

Horizon Power supports a review of Synergy's cost reflective tariffs every five years, as for Western Power's network tariffs, for reasons of increased security of revenue streams and the avoidance of price shocks to consumers. However, Horizon Power recommended the price-setting mechanism incorporate triggers for review (e.g. if economic or market conditions change from those on which prices were based). Further, it may be necessary to review tariffs more frequently to reflect the variability in the market price of carbon, once this is floated.

[62] Synergy submission on issues paper, p7.

Electricity Supply Association of Australia (esaa)

esaa submitted that:[63]

> retail price regulation should be applied by an independent body such as the Authority, through a formal, transparent and consultative process;

and that:

> regulated prices should be cost reflective and derived from a consistent and predictable price setting methodology.

However, esaa did not make any comment on how often cost reflective prices for Synergy should be reviewed.

Alinta Energy (Alinta)

Alinta supported the role of the Authority, as an independent regulatory body, in conducting the inquiry and establishing cost reflective electricity tariff levels for consumers. However, Alinta did not make any recommendations on how frequently Synergy's tariffs should be reviewed.

9.3.2 Authority Assessment

The Federal Government plans to introduce 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.

9.3.2.1 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:

[63] Electricity Supply Association of Australia (esaa) submission on the issues paper, p2.

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.

Draft Recommendation

20) 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.

21) The Authority recommends that if there are significant changes to economic conditions, a mid-period review 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.[64]

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.[65] 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.

[64] 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.

[65] 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.[66]

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.[67] 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.[68]

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[69] 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.

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.[70] From the tariff revenue it collects,

[66] Verve Energy (2011), website www.verveenergy.com.au.

[67] Verve Energy (2011), Annual Report p13.

[68] Western Power (2011), Annual Report pp13-14.

[69] ERA website, www.erawa.com.au

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

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.[71]

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.[72]

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.

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.[73]

The Wholesale Electricity Market

In 2006, another key Government reform was to establish a Wholesale Electricity Market (WEM) to operate within the SWIS.

[71] This requirement also applies to the other electricity retailers in Western Australia.

[72] Horizon Power (2011), Annual Report p4.

[73] ERA (2011), Final report into the Funding Arrangements of Horizon Power.

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.[74]

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[75] 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').

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[76] traded under the original Vesting Contract (2006) reduced over time with the operation of the Displacement Mechanism and as contestable[77] 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[78] 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.

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[74] IMO (2006), The South West Interconnected System Wholesale Electricity Market: An Overview, pp. 6-7

[75] 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.

[76] 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).

[77] Contestable customers consume more than 50 MWh per annum and can choose their electricity retailer.

[78] Supply capacity includes both generation and demand side management.

The Displacement Mechanism also played a role in providing information to the market[79] and facilitated the entry of new private generators. The value of private investment in electricity generation since 2006 is around $2.6 billion.[80]

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.[81] The Market Rules list the IMO's services as:[82]

- 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.[83] Further functions of System Management are to:[84]

- 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:

[79] The Displacement Mechanism included requirements to publish information about demand, vesting prices, volumes and Synergy's displacement requirements.

[80] 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.

[81] The IMO's functions are listed in Clause 2.1.2 of the Market Rules.

[82] Market Rules, Clause 2.22.1

[83] Clause 2.2.1 of the Market Rules.

[84] Clause 2.2.2 of the Market Rules.

- 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.[85] In March 2010, the Authority determined the allowable revenues of the IMO and System Management entities for the period 2010/11 to 2012/13.[86]

- 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.
- 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.[87] 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.

[85] 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.

[86] 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.

[87] *IMO Operational Strategy 2011/12*, pp11-13.

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),[88] 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.[89]
- In return for receiving capacity payments, generators (and Demand Side Management (DSM) providers[90]) are required to offer their capacity into the market at all times (unless otherwise approved, e.g. undergoing scheduled maintenance).

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[91] (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'.[92] 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)[93] 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

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88 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.

89 ERA (2011), Decision on the Maximum Reserve Capacity Price proposed by the Independent Market Operator for the 2013/14 Reserve Capacity Year.

90 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.

91 Capacity payments per MWh are equivalent for the certified capacity of generators and DSM providers.

92 Independent Market Operator (2009), Reserve Capacity Mechanism Progress Report, p4.

93 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.

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.[94]

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.

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[95] then matches physical supply and demand in the system through real-time balancing.[96] 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.[97] 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

[94] 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

[95] 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.

[96] "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.

[97] ERA (2011), 2010 Wholesale Electricity Market Report for the Minister for Energy, p53.

electricity supplies are of acceptable quality. The following types of ancillary services are defined in the Market Rules: [98]

- **Load Following**. Load following is the primary mechanism in real-time to ensure that supply and demand are balanced and system frequency is maintained.[99] 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).
- **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.[100] 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.[101]

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;[102] 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

[98] IMO website (http:/www.imowa.com.au/ancillary-services-types)

[99] 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.

[100] For more information see www.unfccc.int Kyoto

[101] Office of Energy (2010), Renewable Energy Handbook Western Australia 2010, p12.

[102] 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.

> renewable energy sources by 2020.[103] 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
- 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.[104] 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."[105]

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.[106]

[103] This is equivalent to 45,000 GWh: www.climatechange.gov.au.

[104] Alternatively, STCs can be purchased through the STC clearing house, also managed by ORER, for a fixed price of $40 per certificate.

[105] ORER website www.orer.gov.au/publications/lret-sres-basics.html.

[106] ORER (2011), Media release 'Strong compliance by liable entities'.

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;
>
> (b) to purchase or otherwise acquire electricity for the purposes of paragraph (a);"[107]

In undertaking its functions, Synergy must act in accordance with prudent commercial principles and attempt to make a profit.[108]

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.[109]

However, Synergy's main reporting requirement is undertaken as part of its electricity retail licence obligations.[110] Synergy reports against performance standards covering billing, payment arrangements, answering customer queries and complaints and compensating customers for breaches of particular service standards.[111] Each year the Authority publishes its report on the performance of electricity retailers, the latest version of which is the 2010/11 report.[112]

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.

[107] Electricity Corporations Act 2005. Section 44 (a) and (b).

[108] Electricity Corporations Act 2005, Section 61 (1) (a) and (b).

[109] For example, Synergy Annual Report 2009/10, p17

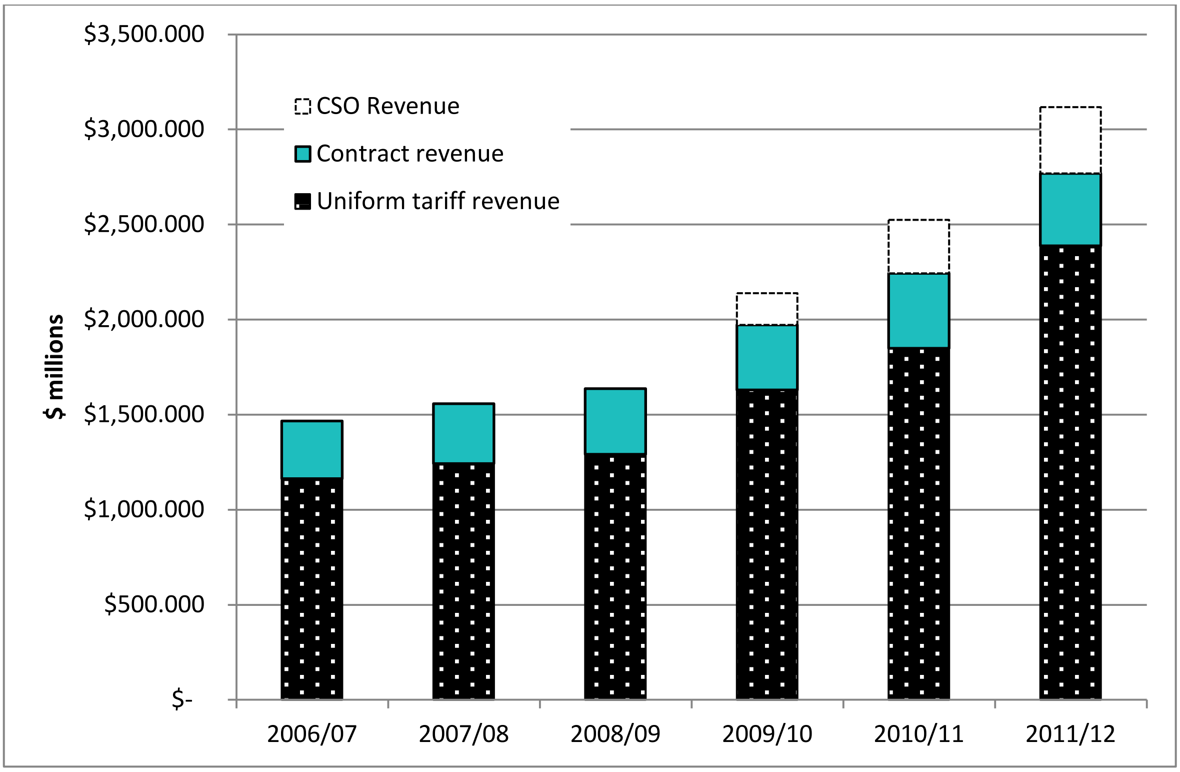
[110] As with all electricity retail licences, Synergy's licence includes a condition that it must provide to the Authority any information the Authority requires to fulfil its functions under the *Electricity Industry Act 2004*. The Authority has specified the performance information it requires for Synergy and other electricity retailers in the Electricity Compliance Reporting Manual.

[111] The Code of Conduct includes service standard payments for facilitating customer reconnections (after disconnection), wrongful disconnection and customer complaint handling.

[112] ERA (2012), www.erawa.com.au 2010/11 Annual Performance Report - Electricity Retailers

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.

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.[113]
  - 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

[113] Synergy (2011), email from Synergy to ERA dated 8 April 2011.

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.

- 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[114] 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.[115]

[114] The SmartPower tariff has been introduced by Synergy and is not a regulated tariff under the By-Laws.

[115] 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.[116]

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.[117] 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.

[116] OOE (2009), Electricity Retail Market Review, p34

[117] 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[118] 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.[119] 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
$111.11/GJ 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
$55.56/GJ 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'.[120]

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
$52.78/GJ funding arrangements of Horizon Power. The Authority calculated a DWAT of 19 cents
$55.56/GJ 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.

[118] Some customers may just require their existing meter to be reprogrammed.

[119] Synergy website, www.synergy.net.au/docs/rebs_pricing_schedule.pdf.

[120] 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 CSO's 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."[121]

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.

[121] 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 9.2.1 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.[122]

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.

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.

[122] Alinta (2011) , verbal confirmation of amount to ERA in April 2011

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.[123]

As Synergy is currently prevented from engaging in generation activities itself,[124] 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".[125]

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) either through additional supplies from bilateral contracts (long or short term)[126] 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

[123] ERA (2011), 2010 Annual Wholesale Electricity Market Report to the Minister for Energy

[124] Electricity Corporations Act 2005, section 47(1)

[125] Synergy Quarterly Report: 1 October 2010 – 31 December 2010

[126] Long term bilateral contracts typically have supply tranches (a base 'take-or-pay' tranche and options on additional supply tranches) with differing prices.

through the Balancing Market. There are price and quantity risks associated with being exposed to the Balancing Market.[127]

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,[128] 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.[129] 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.[130]

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
- 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,[131] or purchasing STCs from the STC

[127] 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.

[128] Synergy is registered in the WEM for the provision of DSM and has certified Capacity Credits of 40MW for the 2011/12 Capacity Year.

[129] In Synergy's financial statements, the REC's liability is recognised at the average market price of REC purchased for the period.

[130] 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.

[131] $65 per REC not surrendered for the 2010 compliance year and $65 per LGC/STC not surrendered for 2011 and future years.

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.[132] 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.[133]

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[134] was made to Synergy and the gazetted TEC amount was $175.7 million.[135]

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.

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.[136] 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.

[132] As a result of Synergy's Supply Procurement program required under the Displacement Mechanism in the original Vesting Contract (2006).

[133] Synergy (2010), Statement of Corporate Intent 2010/11, this contract was worth an estimated $1.5 billion.

[134] Department of Treasury and Finance (2011), 2001/12 Budget Paper No. 3, Appendix 8, p293.

[135] Government Gazette (2009), No. 208, 17 November 2009, p4639.

[136] 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.

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.

Appendix C. Synergy's Current Tariffs

This table has been converted to SI metric units in the Energy prices compared bookmark

Synergy's current tariffs listed in: WA Energy Operator (Powers) Act 1979 – Energy Operators (Electricity Retail Corporation) (Charges) By-laws 2006, as at 01 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:

$$WACC_{\text{nominal post-tax}} = E\left(R_e\right) \times \frac{E}{V} \times + E\left(R_d\right) \times \frac{D}{V}\left(1 - T_c\right)$$

where:

- $E\left(R_e\right)$ is the nominal post-tax expected rate of return on equity – the cost of equity;
- $E\left(R_d\right)$ 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:

$$WACC = E\left(R_e\right)\times\frac{E}{V}\times\frac{1-T_c}{\left(1-T_c\left(1-\gamma\right)\right)}+E\left(R_d\right)\times\frac{D}{V}\left(1-T_c\right)$$

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 $\left(1-T_c\right)$, which can be expressed as:

$$WACC = E\left(R_e\right)\times\frac{E}{V}\times\frac{1}{\left(1-T_c\left(1-\gamma\right)\right)}+E\left(R_d\right)\times\frac{D}{V}$$

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 3.67 per cent using yields from the 5-year Commonwealth Government bonds reported by the RBA, as at 29 February 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[137] such as:

- reliance on contentious assumptions, such as:
    - o markets are perfectly priced at all times; and
    - o forecast dividend distributions accurately reflect market expectations;
- forecasts are highly variable:
    - o small, plausible changes to inputs and assumptions produce large changes in MRP estimates; and
    - o 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.

[137] 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;[138]
    - 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[139] 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.[140] 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.

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.

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[138] 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.

[139] 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.

[140] 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.

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.[141]

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.[142] 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 $(t-1)$.

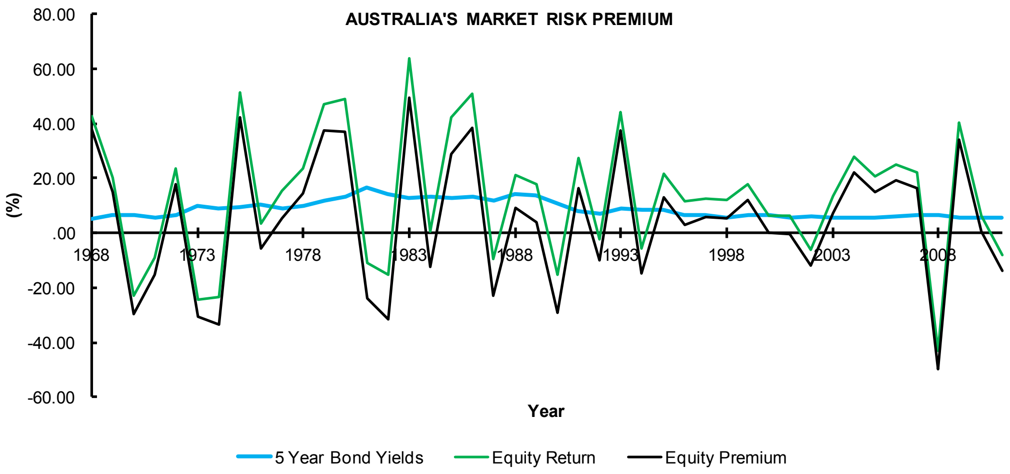
Figure 9 Australia's Market Risk Premium 1969 - 2011 (%)

27. Figure 9 below presents the estimates of Australia's MRP for the period from 1969 to 2011.

[141] Handley, 2008, "A Note on the Historical Equity Risk Premium", A report for the Australian Energy Regulator, 17 October 2008, page 4.

[142] 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][143] 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.

[143] 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.[144] However, the Authority is aware that this information preceded the global financial crisis in 2008.

31. Surveys in 2009[145] and 2010[146] 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.[147]

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.[148]

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.[149]

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144 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.

145 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.

146 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.

147 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.

148 Oliver, Shane, 2011, *Why are Australian shares lagging? Will it continue?* AMP Capital Investors, January 2011, page 2.

149 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.[150]

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.[151] 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.[152]

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.[153]

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.

[150] The Australian Competition and Consumer Commission, 2011, *Network,* Issue 41, September 2011, page 11.

[151] 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.

[152] 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.

[153] 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.

Draft Determination

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. The Authority notes that statistical estimates of beta values for Australian energy network businesses in the period since 2002 point to a value of equity beta at a gearing of 60 per cent debt to assets to be in the range of 0.45 to 0.7. Higher estimates of up to about 1.0 are produced by some estimation methods from the longer period of data for Australian businesses or data for United States businesses.

46. 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 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.

47. The Authority has conducted its own analysis with regard to the estimates of the equity beta. The Authority has used the same approach as adopted by Henry in his study, using an updated data set until October 2011.

48. The Authority's analysis, using the extended dataset to October 2011, can be summarised as below:

- the estimates of the equity beta using monthly data range from 0.0675 to 0.9688, with a mean of 0.4569 and median of 0.4253; and
- the estimates of the equity beta using weekly data range from 0.2168 to 1.3378, with a mean of 0.5204 and median of 0.4261.

49. 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.

50. The Authority notes that the above equity beta of 0.65 adopted for Western Power is derived from a sample of companies with the assumed gearing of 60 per cent. As such, this is not the equity beta to determine the return on equity for Synergy because Synergy has a zero gearing.

51. The Authority considers that Western Power and Synergy should have the same level of business risk which is reflected in the value of the asset beta. It means that the asset betas for Synergy should be the asset beta for Western Power.

52. Current practice by Australian economic regulator presents that the beta of the hypothetical portfolio is just the weighted average of the debt and equity betas:

$$\beta_{asset} = \beta_{portfolio} = \frac{D}{V} \times \beta_{debt} + \frac{E}{V} \times \beta_{equity}$$

53. With the gearing level of 60 per cent and the equity beta of 0.65, and assuming a debt beta of 0.17,[154] the asset beta for Western Power is 0.36.

54. With zero gearing level, the asset beta and the equity beta for Synergy should be the same. As such, the Authority, with its caution on the assumed value of debt beta of 0.17, considers that the equity beta for Synergy should be 0.36 for the purpose of this inquiry.

[154] The Authority is aware that there is no formal estimate of a debt beta in Australia. Current practice generally assumes the equity beta of zero given its empirical estimates for other countries fall within the range of 0.1 and 0.2. For this inquiry, the Authority adopted the estimates of equity beta of 0.17 from Brealey & Myers, 2003, *Principles of Corporate Finance*, Seventh Edition, McGraw-Hill/Irwin, page 229.

Draft Determination

55. In conclusion, the Authority is of the view that an equity beta of 0.36 is reasonable for the purpose of this draft report.

Benchmark Financing Structure: Debt versus Equity

56. 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. Current practice by Australian regulators for a gearing level for a benchmark firm is to adopt the ratio of 60:40.

57. Given the nature of business activities for Synergy, the Authority considers that the gearing level of zero is appropriate for Synergy. The Authority is of the view that Synergy's entire capital is entirely financed by equity which is the State Government of Western Australia.

The Cost of Debt (R_d)

58. Given the assumed gearing level of zero is adopted for Synergy for the purpose of this inquiry, an estimate of the cost of debt for the business is not required.

Inflation Rate

59. 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.

60. However, the Authority is aware that Synergy has used 2.5 per cent as expected inflation rate in their forecast. As such, the Authority has adopted the forecast inflation rate for this draft report of 2.50 per cent.

Corporate Tax Rate

61. 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

62. 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.

63. 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.

64. 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.[155] 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.

65. 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.

Payout Ratio (F)

66. 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.

67. 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.[156] 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.

68. In conclusion, the Authority's decision is to adopt the payout ratio of 70 per cent in this draft report.

[155] 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.

[156] Australian Competition Tribunal, Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9 (24 December 2010), paragraph 4

Theta (θ)

69. 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).

70. The Authority maintains its position in its previous regulatory decision[157] 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.

71. For the same reason as discussed in paragraph 67 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.[158]

Gamma (γ)

72. 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.[159]

Draft Determination

73. The Authority adopts the estimate of gamma of 0.25 to derive the cost of capital for this purpose of this draft report.

[157] 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.

[158] Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011), paragraph 38

[159] Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011), paragraph 42

Conclusion on Rate of Return

74. 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:

Table 41 A Determination of a Rate of Return (as at 29 February 2012)

Parameter	Value
Nominal Risk Free Rate (R_f)	3.67%
Real Risk Free Rate (R_f^r)	1.14%
Inflation Rate π_e	2.50%
Debt Proportion (D)	0%
Equity Proportion (E)	100%
Australian Market Risk Premium (MRP)	6%
Equity Beta (β_e)	0.36
Debt Beta (β_d)	0.17
Corporate Tax Rate (T_c)	30%
Franking Credit (γ)	25%
Nominal Pre Tax Cost of Equity $(R_e^{n,\text{pre-tax}})$	7.52%
Real Pre Tax Cost of Equity $(R_e^{r,\text{pre-tax}})$	4.90%
Nominal After Tax Cost of Equity $(R_e^{n,\text{post-tax}})$	5.83%
Real After Tax Cost of Equity $(R_e^{r,\text{post-tax}})$	3.25%

Source: ERA Analysis

Table 42 Authority's estimates of WACC for Synergy

WACC	**Value (Per cent)**
Nominal Pre Tax WACC $\left(WACC_n^{\text{pre-tax}}\right)$	7.52
Real Pre Tax WACC $\left(WACC_r^{\text{pre-tax}}\right)$	4.90
Nominal After Tax WACC $\left(WACC_n^{\text{post-tax}}\right)$	5.83
Real After Tax WACC $\left(WACC_r^{\text{post-tax}}\right)$	3.25

Source: ERA Analysis

The key difference between the rate of return for Synergy and the rate of return for Western Power is that Synergy is not exposed to financial risk as its gearing level is effectively zero. The WACC that has been calculated for Synergy reflects only the cost of equity rather than a weighted average of the costs of equity and debt. The Authority considers that both Synergy and Western Power should have the same level of systematic risk. As such, the asset beta for both companies should be the same. With zero gearing, this capital structure results in a lower value of the equity beta for Synergy in comparison with that for Western Power. This view is based on the following two grounds:

- First, both Western Power and Synergy face the same level of business risk (the risk the company will have lower anticipated profits and even a loss due to a change in sales, cost, economic environment and government regulations. Only Western Power faces financial risk, the risk that the company may not have adequate cash flow to meet its financial obligation, because Synergy has a gearing level of zero.

- Second, for a company with a non-zero gearing level, debt holders will all be claimants to the company before the equity holders.. The higher debt the company has, the higher the risk faced by equity holders and debt holders.. As such, from the view of an equity holder, the return on equity for Western Power is expected to be higher than that for Synergy because Synergy has no gearing. A zero gearing level for Synergy will drive the equity beta for Synergy to be lower than the equity beta of 0.65 which is adopted for the recent determination of the WACC for Western Power. An equity beta of 0.36 with zero gearing level is equivalent with an equity beta of 0.65 for a gearing of 60 per cent for Western Power.

In summary, the Authority is of the view that the return on equity for Synergy should be lower than that for Western Power because Synergy's gearing level is zero. However, given the cost of equity is more expensive than the cost of debt, the weighted average cost of capital for Synergy could be higher, lower, or equal to that of Western Power depending on the cost of debt for Western Power.

Given the uncertainties with regards to the assumption of debt beta in the process of leveraging and deleveraging; the Authority considers that adopting the nominal pre-tax WACC of Western Power in Synergy's inquiry is appropriate.

For this draft report, the nominal pre-tax rate of return is determined to be 7.40 per cent as at 29 February 2012 as determined in the draft decision on Western Power Network Access Arrangement released in March 2012. This return of 7.40 per cent is applied to the estimates of the asset base for Synergy to reflect the dollar value of the retail margin.

Appendix F. Synergy’s Concessions and Rebates

The following concessions and rebates are currently available to Synergy customers:

Table 43 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 $139.69 /year
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 What happens if a person is an all electric home compared to one with gas connected? kW 2.45 3.11 3.77 4.43	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 0.720 GJ = 284 W
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) 0.720 GJ =284 W
Thermoregulatory dysfunction energy subsidy	Financially disadvantaged and have medical advice that you need temperature control (a/c, heating)	$527 pa paid annually in advance =240 W

Base load	The power averaged every second over a whole year
c/kWh	GJ = (c/kWh)/0.36
$/MWh	GJ = ($/MWh)/3.6

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 Competition / 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
Efficiency (%)	Power out x 100/power in

GJ	GigaJoule is an SI unit of energy =1,000,000,000 J
GWh	Gigawatt hour = 3600 GJ
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 0.0036 GJ
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 =3.6 GJ
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
[redacted]	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
Year	31556926 seconds and includes the effects of leap year