Electricity Retail Market Review – Electricity Tariffs

FINAL RECOMMENDATIONS PREPARED FOR THE WESTERN AUSTRALIAN OFFICE OF ENERGY

January 2009

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Executive summary

The Minister for Energy is currently conducting the Electricity Retail Market Review (Review). The Office of Energy (OOE) has responsibility for completing the Review and preparing recommendations for the Minister's consideration. Frontier Economics has been retained by the OOE to advise on each aspect of the Review. This report sets out Frontier Economics' final recommendations to the OOE in respect of the review and assessment of electricity retail tariff arrangements.

The key focus of this report is to determine the cost-reflective level and appropriate structure of each of the regulated tariffs within the South West Interconnected System (SWIS), and the impact on customers of moving to cost-reflective tariffs.

In determining cost reflective tariffs, a building block approach to the costs of supplying electricity is adopted. The focus in this report is determining the "R" component of tariffs, which includes the following:

- wholesale costs, including the costs of both black and green electricity;
- ancillary services costs and market fees;
- retail operating costs; and
- the retail margin.

Our analysis of these components of the cost of supplying electricity indicates that the existing regulated tariffs are significantly below cost-reflective levels. This is particularly the case for tariffs for small use customers. Tariffs for these customers have not increased in many years, with the result that these tariffs have failed to keep track with increases in the cost of supplying electricity.

The most substantial cost in the R component of tariffs is the wholesale cost of electricity. Recent increases in the costs of inputs into the wholesale cost of electricity provide an indication of the extent to which the costs of supplying electricity have increased in recent years:

- gas prices in Western Australia have increased significantly in recent years, increasing the costs of fuel for electricity generation;
- coal prices are likely to increase to reflect increases in gas prices, also increasing the costs of fuel for electricity generation; and
- the capital costs associated with building new generation plant in Western Australia are high, reflecting the broader economic conditions in Western Australia.

The result of increases in these cost inputs is that the implied wholesale cost of electricity underpinning the existing regulated tariffs is no longer sufficient to cover the costs of supplying electricity in Western Australia. This is reflected in our modelling.

The wholesale cost of electricity in Western Australia is likely to further increase over the period for this review as a result of greenhouse gas emissions mitigation

policies. Renewable energy targets in Australia will become more stringent over the period for this review, and a national emissions trading scheme will be introduced. These policies will add significantly to the wholesale cost of electricity. The forecast impact of these policies is incorporated in the cost-reflective tariffs set out in this report.

In determining the impact on customers of moving to cost-reflective tariffs, the other major component of customers' total bills is network charges (also known as the "N" component of tariffs). While network charges are determined independently by the Economic Regulation Authority, the available information suggests that network charges will increase over the period for this review. This contributes to the impact on customers' bills of moving to cost reflective tariffs.

1 Introduction

The Minister for Energy is currently conducting the Electricity Retail Market Review (Review). The Office of Energy (OOE) has responsibility for completing this review and preparing recommendations for the Minister's consideration.

There are three related aspects to this review:

- a review and assessment of electricity retail tariff arrangements;
- an assessment of the costs and benefits of the implementation of electricity full retail competition (FRC) in Western Australia; and
- an assessment of the roll out of smart meters.

Frontier Economics has been retained by the OOE to advise on each aspect of this Review.

1.1 PROCESS

As part of this Review, the OOE and Frontier Economics have engaged in public consultation.

In August 2007, the OOE released an Issues Paper to key stakeholders, and invited submissions from those stakeholders. In December 2007, the OOE released an amended version of the Issues Paper to the broader public, and invited public submissions. Copies of the non-confidential components of all submissions have been released on the OOE's web site.[1] These submissions have been considered in developing the final recommendations set out in this report.

In August 2007, the OOE released a Data Request to key stakeholders. Staff from the OOE and Frontier Economics held meetings with key stakeholders to discuss the approach to this review and the Data Request. Subsequently, stakeholders have provided data on a confidential basis either to both the OOE and Frontier Economics, or to Frontier Economics alone. The data provided has been taken into account in developing the final recommendations set out in this report.

In April 2008, the OOE released Frontier Economics' draft recommendations report on electricity tariffs, and invited public submissions. Subsequently, stakeholders have provided submissions commenting on aspects of Frontier Economics' draft recommendations report. These comments have been taken into account in developing the final recommendations set out in this report. Responses to specific issues raised in submissions are set out in Appendix 4 of this report.

[1] www.energy.wa.gov.au

1.2 THIS REPORT

This report sets out Frontier Economics' final recommendations to the OOE in respect of the review and assessment of electricity retail tariff arrangements.

Frontier Economics has also provided reports to the OOE setting out Frontier Economics' draft recommendations to the OOE in respect of the assessment of the costs and benefits of the implementation of FRC in Western Australia, and in respect of the assessment of the roll out of smart meters. These two reports will be released for public consultation.

1.3 STRUCTURE OF THIS REPORT

This report is structured as follows:

- Section 2 provides the policy background within which this Review is undertaken.
- Section 3 discusses the approach to this review and assessment of electricity retail tariff arrangements.
- Section 4 provides an overview of the current regulated tariffs.
- Section 5 through Section 9 discuss each of the cost components of retail tariffs.
- Section 10 sets out a set of tariffs that reflect these cost components.
- Section 11 provides an overview of network tariffs, including a consideration of the tariff equalisation fund.
- Section 12 considers the combined impact of the new retail and network tariffs on customer bills.
- Section 13 considers options for future reviews of regulated electricity tariffs.

2 Existing policy arrangements

This review and assessment of electricity tariff arrangements is undertaken within the context of the existing policy arrangements within Western Australia. These arrangements – in particular, the Vesting Contract, the arrangements for contestability, the uniform tariff policy and the existing retail tariff arrangements – provide the policy framework within which the recommendations set out in this report are provided. This section provides an overview of these arrangements.

2.1 THE VESTING CONTRACT

An important part of the electricity reform process in Western Australia that has been implemented over recent years has been the restructuring of Western Power Corporation. To provide the basis for the development of a competitive market in Western Australia, Western Power Corporation was disaggregated into separate businesses. Among other things, the disaggregation of Western Power provided for the creation of a generation business (Verve Energy) and a retail business (Synergy) in the South West Interconnected System (SWIS).

With the separation of generation from retail functions in the SWIS, it was necessary to provide for contractual arrangements between Verve Energy and Synergy as a transitional mechanism to support the development of the Wholesale Electricity Market (WEM). The Minister for Energy determined the Vesting Contract on Verve Energy and Synergy, which set out the initial wholesale supply of capacity and energy from Verve Energy to Synergy.

The quantity of capacity and energy supplied from Verve Energy to Synergy under the Vesting Contract will decline over time. The Capacity Cap governs the supply of capacity and energy under the Vesting Contract, and will decline over time due to:

- the expiry of Synergy's inherited retail contracts;
- contestable customers accepting market contracts and moving off the regulated tariffs; and
- the operation of the displacement mechanism.[2]

2.2 RETAIL CONTESTABILITY IN WESTERN AUSTRALIA

Retail contestability has been progressively introduced in Western Australia since 1999. Nevertheless, regulated tariffs exist for all customers:

- Customers in the SWIS that consume 160 MWh per annum or more are currently contestable, and Synergy is not obliged to supply these customers at the regulated tariffs.

[2] Further information on the Vesting Contract arrangements is available on the OOE website: www.energy.wa.gov.au

- Customers in the SWIS that consume more than 50 MWh per annum but less than 160 MWh per annum are also currently contestable, but these customers have the option of supply from Synergy under the regulated tariffs. Synergy must supply these customers at the regulated tariff if requested.
- Customers in the SWIS that consume 50 MWh per annum or less are currently non-contestable. These customers must be supplied by Synergy at the regulated tariff.

2.3 THE UNIFORM TARIFF POLICY

The Government has a uniform tariff policy such that customers face the same tariffs within the SWIS and outside the SWIS. The Government's uniform tariff applies to all electricity customers supplied by Synergy and Horizon Power throughout the State.

Typically, the cost of supplying electricity in areas outside the SWIS is considerably higher than the revenue that can be collected from customers paying the uniform regulated tariff. The Tariff Equalisation Fund (TEF) funds the difference between the revenue that can be collected and the cost of supplying electricity outside the SWIS. All electricity customers in the SWIS that are connected to the distribution network currently contribute to the TEF through the Tariff Equalisation Contribution (TEC), which is a component of network charges.

The Government remains committed to the uniform tariff policy, and these recommendations are provided within this policy context.

2.4 THE TARIFF BY-LAWS

In Western Australia, electricity retail tariff arrangements are regulated by the Minister for Energy under the *Energy Operators (Powers) Act 1979* (the Act). The Act provides the head of power for:

- the *Energy Operators (Electricity Retail Corporation) (Charges) By-laws 2006* (Synergy Tariff By-laws); and
- the *Energy Operators (Regional Power Corporation) (Charges) By-laws 2006* (Horizon Power Tariff By-laws).

The Synergy Tariff By-laws set out the electricity retail tariff arrangements that apply within the SWIS and the Horizon Power Tariff By-laws set out the electricity retail tariff arrangements that apply outside the SWIS. Some tariffs within the SWIS are effectively mirrored by tariffs outside the SWIS.

3 Approach

This report sets out Frontier Economics' recommendations to the OOE in respect of the review and assessment of electricity tariff arrangements. In providing the recommendations set out in this report, we have been guided by the Terms of Reference to this review. The Terms of Reference are set out in Appendix 1.

Our understanding of the Terms of Reference to this review is that there are four key questions that are to be addressed in the review and assessment of electricity tariff arrangements:

- Is the current set of tariffs appropriate, or should some other set of tariffs be adopted?
- What is the cost-reflective level and appropriate structure of each retail tariff?
- What is the impact of moving to cost-reflective tariffs on different classes of customers?
- What is the appropriate adjustment mechanism for future tariff reviews?

These key questions, and our approach to addressing these questions, are discussed in further detail in the sections below.

3.1 DETERMINING THE APPROPRIATE SET OF TARIFFS

The Terms of Reference for this review require consideration of whether the existing regulated tariffs are appropriate, or some other set of regulated tariffs are appropriate. In determining the appropriate set of regulated tariffs, three considerations are particularly important:

- **Policy considerations**. In some cases, regulated tariffs exist for policy reasons. Where this is the case – for instance, the C1 and D1 tariffs for community and charitable organisations – it is worth considering whether the regulated tariffs are the best policy option.
- **The cost of supplying electricity**. It makes sense to have different regulated tariffs if there are different costs to supplying electricity to different customers. In order that customers face cost-reflective tariffs, different tariffs are required for customers with different costs.
- **The structure of tariffs**. It makes sense to have different regulated tariff where it is appropriate for different customers to face tariffs with different structures. For instance, time of use tariffs may be appropriate for some customers but not others.

3.2 DETERMINING COST REFLECTIVE TARIFFS

In determining cost reflective tariffs, this report focuses on retail electricity tariffs within the SWIS. With the uniform tariff policy, applicable regulated electricity tariffs in areas outside the SWIS are set at the same level as equivalent electricity

tariffs within the SWIS. However, this report considers the impact of moving to new tariff levels on the funding required under the TEF.

In determining cost reflective tariffs within the SWIS, a building block approach to the costs of supplying electricity is adopted.

The following components of the cost of supplying electricity are estimated:

- wholesale costs, including the costs of both black and green electricity;
- ancillary services costs and market fees;
- retail operating costs; and
- the retail margin.

These costs comprise what is commonly referred to as the "R" component of tariffs.

In addition to the R component of tariffs, retailers also face network charges, or the N component of tariffs. In Western Australia, the Economic Regulation Authority (ERA) determines network charges. Network charges are not separately assessed in this review. However, in considering the impact on customer bills of moving to cost-reflective tariffs, both the R component and the N component of tariffs are considered.

For the purposes of this review, costs are estimated, and retail tariffs determined, over the period up to 2011/12.

These R components of the retail tariffs are discussed in Section 5 through Section 9 of this report. Network tariffs are discussed in Section 11.

3.3 THE IMPACT OF MOVING TO COST-REFLECTIVE TARIFFS

In the past, regulated retail tariffs have not been regularly adjusted to reflect changes in costs.[3] At the same time, the cost of supplying electricity in Western Australia has risen in recent years, particularly as a result of increases in the cost of inputs to the supply of electricity. As a result, the existing regulated tariffs in the SWIS are not reflective of the costs of supplying the average customers on those tariffs.

In order that tariffs are set at cost-reflective levels, increases in regulated tariffs are required. It is important that the impact of these increases in regulated tariffs is manageable for customers. For this reason, this report considers the impact of moving to cost-reflective tariffs on various types of customers. Since non-contestable customers have no options other than the regulated tariffs, the focus will be on the impact of changes in regulated tariffs on these non-contestable customers.

[3] Until July 2007, business tariffs had not increased in nominal terms since 1991/92. Residential tariffs have not increased in nominal terms since 1997/98.

The impact on customers of moving to cost-reflective tariffs is discussed in Section 12 of this report.

3.4 DETERMINING THE APPROPRIATE ADJUSTMENT MECHANISM

In order that regulated tariffs remain at cost-reflective levels in future, it is appropriate to put in place a formal process for regular reviews of electricity tariffs. The appropriate mechanism by which regulated reviews should be undertaken is discussed in Section 13 of this report.

4 Regulated tariffs

The Terms of Reference for this review requires consideration of whether the existing regulated tariffs are appropriate, or some other set of tariffs is appropriate. Decisions about the appropriate set of regulated tariffs can be guided by policy considerations or cost considerations. These are addressed in the sections below. First, however, an overview of the current set of regulated tariffs is provided.

4.1 TARIFFS

The Synergy Tariff By-Laws set out residential, community and business tariffs that apply within the SWIS. An overview of each of these tariffs is provided below, including characteristics of the consumption of customers served under each tariff.

The Horizon Tariff By-Laws set out residential, community and business tariffs that apply outside the SWIS. These are also discussed below. In most cases these tariffs mirror the tariffs within the SWIS.

A1 Tariff

The A1 tariff is a residential tariff in the SWIS. It is only available to residential premises where the supply is not used for any industrial, commercial, business or general purpose. The A2 tariff is equivalent to the A1 tariff, and is available outside the SWIS.

The existing A1 tariff includes a fixed and variable component. The tariff rates, including GST, are set out below.

Fixed charge (first dwelling)	25.57 c/day
Fixed charge (each additional dwelling)	19.86 c/day
Metered rate	13.94 c/kWh

All customers on the A1 tariff are on the Anytime Energy (Residential) network tariff.

There are close to 800,000 customer accounts on the A1 tariff. For the majority of these accounts, consumption is relatively modest: the average consumption by customers on the A1 tariff is approximately 5,200 kWh per annum, almost 90 per cent of residential customers consume less than 10,000 kWh per annum, and all but a handful of customers on the A1 tariff are below the 50,000 kWh per annum threshold for contestability.

Based on the load factor, the load of customers on the A1 tariff is relatively peaky, as is typical of residential consumption throughout Australia.

B1 Tariff

The B1 tariff is a residential water-heating tariff. The B1 tariff is available for residential water heating during a six hour period between the hours of 11pm and 6am.

The existing B1 tariff includes a fixed and variable component. The tariff rates, including GST, are set out below.

Fixed charge	12.84 c/day
Metered rate	7.10 c/kWh

The B1 tariff is not currently being offered to customers. However, there remain a number of customers on the B1 tariff. Information provided to the OOE since the release of Frontier Economics' draft recommendations report indicate that the number of customers remaining on the B1 tariff is significantly greater than indicated by the information provided prior to the release of Frontier Economics' draft recommendations report. Given this, there is a stronger argument for the B1 tariff remaining in the gazetted tariffs and, therefore, Frontier Economics has estimated a cost reflective B1 tariff for this final recommendations report.

C1 Tariff

The C1 tariff is a community service tariff available for voluntary and charitable organisations in the SWIS. The C2 tariff is equivalent to the C1 tariff, and is available outside the SWIS.

The existing C1 tariff includes a fixed and variable block component. The tariff rates, including GST, are set out below.

Fixed charge	25.57 c/day
Metered rate (first 20 kWh)	13.94 c/kWh
Metered rate (next 1,630 kWh)	17.47 c/kWh
Metered rate (in excess of 1,650 kWh)	15.76 c/kWh

All customers on the C1 tariff are on the Anytime Energy (Residential) network tariff.

There are approximately 2,000 customer accounts on the C1 tariff. The average consumption of customers on the C1 tariff is approximately 15,000 kWh per

annum, with over 90 per cent of customers on C1 tariffs below the threshold for contestability.

Based on the load factor, the load of customers on the C1 tariff is the peakiest of any regulated tariff in the SWIS.

D1 Tariff

The D1 tariff is a tariff for charitable organisations in the SWIS, and is available only for premises wholly used by a charitable or benevolent organisation for providing residential accommodation other than for commercial gain. The D2 tariff is equivalent to the D1 tariff, and is available outside the SWIS.

The existing D1 tariff includes a fixed and variable component. The tariff rates, including GST, are set out below.

Fixed charge (first dwelling)	25.57 c/day
Fixed charge (each additional dwelling)	13.94 c/day
Metered rate	13.94 c/kWh

All customers on the D1 tariff are on the Anytime Energy (Residential) network tariff.

There are close to 100 customer accounts on the D1 tariff. Average consumption of customers on the D1 tariff is approximately 115,000 kWh per annum. Only about 40 per cent of customers on D1 tariffs consume below the threshold for contestability and a small number have substantial consumption, in excess of 200,000 kWh per annum.

Based on the load factor, the load of customers on the D1 tariff is mid-range relative to the other regulated tariffs: neither particularly peaky nor particularly flat.

K1 Tariff

The K1 tariff is for business and residential purposes in the SWIS. The K1 tariff is available for premises where the circuit wiring is not separate and the electricity is used partly for general purposes and partly for residential purposes. The K2 tariff is equivalent to the K1 tariff, and is available outside the SWIS.

The existing K1 tariff includes a fixed and variable block component. The tariff rates, including GST, are set out below.

Fixed charge	25.57 c/day
Metered rate (first 20 kWh)	13.94 c/kWh
Metered rate (next 1,630 kWh)	17.47 c/kWh
Metered rate (in excess of 1,650 kWh)	15.76 c/kWh

All customers on the K1 tariff are on the Anytime Energy (Business) network tariff.

There are approximately 13,000 customer accounts on the K1 tariff. Average consumption of customers on the K1 tariff is approximately 10,000 kWh per annum. The vast majority of customers on K1 tariffs – over 98 per cent – consume below the threshold for contestability.

Based on the load factor, the load of customers on the K1 tariff is close to the flattest profile of any regulated tariff in the SWIS.

L1 Tariff

The L1 tariff is a business tariff for low/medium voltage use in the SWIS. The L2 tariff is equivalent to the L1 tariff, and is available outside the SWIS.

The existing L1 tariff includes a fixed and variable block component. The tariff rates, including GST, are set out below.

Fixed charge	26.57 c/day
Metered rate (first 1,650 kWh)	17.47 c/kWh
Metered rate (in excess of 1,650 kWh)	15.76 c/kWh

All customers on the L1 tariff are on the Anytime Energy (Business) network tariff.

There are approximately 80,000 customer accounts on the L1 tariff. Average consumption on the L1 tariff is approximately 15,000 kWh per annum. The majority of customers on the L1 tariff – in excess of 93 per cent – consume below the threshold for contestability. However, there are a number of much larger accounts on the L1 tariff.

While the majority of customers on the L1 tariff are below the threshold for contestability, there are nevertheless a significant number of customers on the L1 tariff that are above the threshold for contestability. For this reason, a comment in response to Frontier Economics' draft recommendations report was that the L1 tariff should be split into two tariffs, in the same way that the R1/R3 tariffs are split. This final recommendations report therefore considers appropriate

tariffs for a new L1 tariff (restricted to customers consuming below the threshold for contestability) and for a new L3 tariff (restricted to customers consuming above the threshold for contestability).

Based on the load factor, the load of customers on the existing L1 tariff is close to the peakiest regulated tariff in the SWIS.

M1 Tariff

The M1 tariff is a business tariff for high voltage use in the SWIS. The M1 tariff is available for consumers supplied at 6.6kV, 11kV, 22kV, 33kV or such higher voltage as Synergy may approve. The M2 tariff is equivalent to the M1 tariff, and is available outside the SWIS.

The existing M1 tariff includes a fixed and variable block component. The tariff rates, including GST, are set out below.

Fixed charge	26.57 c/day
Metered rate (first 1,650 kWh)	16.88 c/kWh
Metered rate (in excess of 1,650 kWh)	15.16 c/kWh

All customers on the M1 tariff are on the Anytime Energy (Business) network tariff.

There are relatively few customers supplied at high voltage, with less than 50 customer accounts on the M1 tariff. Average consumption of customers on the M1 tariff is substantial, at approximately 400,000 kWh per annum. Around half of customers on the M1 tariff consume below the threshold for contestability, with the other customers distributed across a wide range of consumption.

Based on the load factor, the load of customers on the M1 tariff is the flattest of any regulated tariff in the SWIS.

R1 Tariff

The R1 tariff is a time of use tariff for users in the SWIS that consume less than 50 MWh per annum. The R1 tariff is only available to small and medium enterprises (SMEs). A typical customer on the R1 tariff might include a retail establishment.

The current R1 tariff and R3 tariff were introduced on 1 July 2007. Prior to 1 July 2007, the old R1 tariff was available to users that consume more or less than 50 MWh per annum. From 1 July 2007, the old R1 tariff was split into the current R1 tariff and the current R3 tariff.

The current R1 tariff includes a fixed and variable time of use component. The tariff rates, including GST, are set out below.

Fixed charge	1.09 $/day
Peak energy charge	19.13 c/kWh
Off-peak energy charge	5.90 c/kWh

All customers on the R1 tariff are on the Time of Use Energy (Large) network tariff.

There are approximately 5,000 customer accounts on the R1 tariff. With the tariff restricted to customers consuming less than 50,000 kWh per annum, average consumption is relatively low for a business tariff, at around 22,000 kWh per annum. With consumption restricted to less than 50,000 kWh per annum, all customers on the R1 tariff are below the threshold for contestability.

R3 Tariff

The R3 tariff is a time of use tariff for users in the SWIS that consume more than 50 MWh per annum. The R3 tariff is only available to larger businesses. A typical customer on the R3 tariff might include a machinery equipment site, an office block or a high school.

The R3 tariff includes a fixed and variable time of use component. The current tariff rates, including GST, are set out below.[4]

Fixed charge	1.25 $/day
Peak energy charge	21.89 c/kWh
Off-peak energy charge	6.75 c/kWh

Almost all customers on the R3 tariff are on the Time of Use Energy (Large) network tariff.

There are approximately 6,000 customer accounts on the R3 tariff. With the tariff restricted to customers consuming 50,000 kWh per annum or more, average consumption is of course larger than the R1 tariff, at almost 200,000 kWh per annum, and all customers are above the threshold for contestability.

[4] The R3 tariff rate has increased since the release of Frontier Economics' draft recommendations report, as set out in the Synergy Tariff By-Laws.

S1 Tariff

The S1 tariff is a time-based demand and energy tariff for low/medium voltage users in the SWIS. A typical customer on the S1 tariff might include a hotel, a bank or a small shopping centre.

The S1 tariff includes a variable time of use component, a demand charge and a minimum charge. The current tariff rates, including GST, are set out below.[5]

Demand charge	70.41 c/day multiplied by the greater of: • on-peak ½ hourly maximum demand; or • 30% of off-peak ½ hourly maximum demand
Peak energy charge	10.09 c/kWh
Off-peak energy charge	6.39 c/kWh
Minimum charge	277.16 $/day

Customers on the S1 tariff are on a number of different network tariffs.

There are approximately 300 customer accounts on the S1 tariff. Most customers on the S1 tariff are large users, with average consumption of around 1,700,000 kWh per annum. Only very few customers on the S1 tariff are below the threshold for contestability.

Based on the load factor, the load of customers on the S1 tariff is comparatively peaky.

T1 Tariff

The T1 tariff is a time-based demand and energy tariff for high voltage users in the SWIS. The T1 tariff is available to consumers supplied at 6.6kV, 11kV, 22kV or 33kV or such higher voltage as Synergy may approve. Typical customers on the T1 tariff include office blocks, district hospitals or mining sites.

The existing T1 tariff includes a variable time of use component, a demand charge and a minimum charge. The current tariff rates, including GST, are set out below.[6]

[5] The S1 tariff rate has increased since the release of Frontier Economics' draft recommendations report, as set out in the Synergy Tariff By-Laws.

[6] The T1 tariff rate has increased since the release of Frontier Economics' draft recommendations report, as set out in the Synergy Tariff By-Laws.

Demand charge	64.43 c/day multiplied by the greater of: • on-peak ½ hourly maximum demand; or • 30% of off-peak ½ hourly maximum demand
Peak energy charge	9.43 c/kWh
Off-peak energy charge	6.28 c/kWh
Minimum charge	$365.64 $/day

Customers on the T1 tariff are on a number of different network tariffs.

There are approximately 100 customer accounts on the T1 tariff. All customers on the T1 tariff are relatively large users, with average consumption of around 4,000,000 kWh per annum. Consumption is relatively widely distributed among customers on this tariff.

Based on the load factor, the load of customers on the T1 tariff is close to the average load profile across all regulated tariffs.

N2 Tariff

The N2 tariff is a tariff for supply to Commonwealth and foreign Government instrumentalities in Horizon Power's non-integrated systems.

The N2 tariff has a price escalator that is tied to Singapore gas prices. The N2 tariff has therefore been increasing annually and does not require further increases.

P2 Tariff

The P2 tariff is a tariff for supply to Commonwealth and foreign Government instrumentalities in Horizon Power's North West Integrated System. The existing P2 tariff includes a fixed and variable component. The tariff rates, including GST, are set out below.

Fixed charge (first dwelling)	13.31 c/day
Metered rate	20.77 c/kWh

W1 Tariff and streetlight tariffs

The W1 tariff is for traffic light installations in the SWIS. The existing W1 tariff is a fixed charge of $1.61 per kW per day, including GST. The W2 tariff is equivalent to the W1 tariff, and is available outside the SWIS.

There is a range of tariffs for streetlights, with different rates per day for streetlights of different wattage, type and operation time.

4.2 POLICY CONSIDERATIONS

In some cases there are policy reasons that suggest a particular set of regulated tariffs is appropriate. In Western Australia, there are policy reasons that suggest that the C1 and D1 tariffs should be removed from the schedule of regulated tariffs, and that the L1 tariff should be split into two new tariffs: an L1 and an L3 tariff.

The C1 and D1 tariffs are tariffs for charitable and community organisations. As discussed in the OOE's Issues Paper, an alternative to offering subsidised tariffs to these organisations is to offer subsidies directly to the customer or to the retailer. This alternative has the advantage of providing more efficient pricing signals to consumers and providing the possibility for effective retail contestability for these tariffs.

Our understanding is that the OOE intends to recommend that the C1 and D1 tariffs be removed, and that the assistance provided by these tariffs be replaced with direct CSO payments. Given this recommendation, this report does not determine cost reflective levels for the C1 and D1 tariffs.

For the existing L1 tariff, while the majority of customers fall below the threshold for contestability, there are nevertheless a significant number of L1 customers that are contestable. Given that the cost to serve small non-contestable customers and large contestable customers differ (as set out in this report) there is reason to split the L1 tariff at the threshold for contestability, as with the R1/R3 tariffs. With customers below the threshold for contestability on a new L1 tariff and customers above the threshold for contestability on a new L3 tariff, the new tariffs will better reflect the cost to serve different customer groups than a single L1 tariff would do.

4.3 COST CONSIDERATIONS

One reason to have different regulated retail tariffs is to reflect differences in the costs of supplying electricity to different classes of customers. For the R component of tariffs, the largest cost of retailing electricity is the wholesale cost of electricity.

Where the cost of electricity component varies across different tariffs, it is appropriate to have different tariffs. As discussed in Section 5, the wholesale cost of electricity component of each of the regulated tariffs that we model are, in fact, different. This suggests that the existing tariffs should not be aggregated.

There is also a question as to whether the existing tariffs should be disaggregated. This would be appropriate for reasons of cost-reflectivity if there is reason to think that the wholesale cost (in $/MWh) for different groups of customers within a specific tariff are different. The key driver of differences in wholesale costs for different groups of customers is differences in the load profile for customers. We were unable to get information on the load profile for different

groups of customers within particular tariffs, and are therefore unable to determine whether there is reason to further disaggregate existing tariffs. In part, this lack of information reflects the fact that most customers in Western Australia remain on accumulation meters. This limits the availability of data on the load profile for most customers.

For the purposes of future tariff reviews, improved information on load profiles of groups of customers on specific tariffs would assist in determining both an appropriate set of tariffs and an appropriate structure for tariffs.

5 Allowance for black wholesale costs

Wholesale costs are those costs that retailers incur in acquiring energy and capacity in the wholesale market. Wholesale costs are generally considered to consist of the following components:

- Black wholesale costs. The black wholesale cost is the cost of the mix of wholesale energy and capacity that would be acquired in the absence of any greenhouse gas emissions mitigation policies.
- Green wholesale costs. The green wholesale cost is the additional cost of complying with greenhouse gas emissions mitigation policies.

This section considers black wholesale costs for each of the regulated tariffs in the SWIS. Green wholesale costs are considered in Section 6.

5.1 APPROACH

There are several possible approaches to assessing wholesale costs for the purposes of determining regulated tariffs. This section discusses the principal alternatives, sets out the approach adopted for the purposes of this review, and provides the logic for that approach.

5.1.1 Actual cost or efficient cost?

Wholesale costs can be thought of in two ways: the costs that existing generators in the market would face, given their existing portfolio of generation plant and fuel contracts; or the costs that an efficient retailer would face in purchasing electricity from generators that are exposed to prevailing market prices.

From the perspective of providing appropriate incentives for investment, the efficient wholesale cost is generally preferred. The reason is that this provides appropriate incentives: to existing generators to operate efficiently, and to investors to build new plant when it is required to meet system load.

However, setting wholesale costs on the basis of efficient costs can provide incumbent generators with a return in excess of their costs. This is particularly the case where incumbent generators benefit from lower capital costs or lower priced fuel contracts than new entrants would be able to achieve.

This issue is particularly relevant for the purposes of estimating wholesale costs for non-contestable customers in Western Australia. As discussed in Section 2, as part of the reform process in Western Australia, a Vesting Contract was established between Verve Energy and Synergy. This Vesting Contract accounts for a large proportion of the capacity and energy that Synergy requires to meet the load of contestable and non-contestable customers over the period from 2008/09 to 2011/12.

The netback pricing arrangements under the Vesting Contract result in Synergy paying Verve Energy a price that is determined by deducting network costs, retail operating costs, a retail margin and other market costs from the tariff revenue that Synergy receives. If market fuel prices are in excess of prices under existing

fuel contracts, and if regulated tariffs are set on the basis of the efficient wholesale cost, the result of the net-back pricing arrangement is that Verve Energy may receive a price under the Vesting Contract that is in excess of its total costs and appropriate net margin, and non-contestable customers will fund that price through regulated tariffs.

Due to these Vesting Contract arrangements, we have estimated the wholesale cost for non-contestable customers as a blend of efficient wholesale costs and the actual costs that Verve Energy would face in operating a sustainable business (Verve Energy's sustainable energy price), as discussed further in Section 5.4. This approach avoids a situation where Verve Energy will receive revenues under the Vesting Contract in excess of its total cost, and ensures that non-contestable customers do not face tariffs in excess of those required to compensate Verve Energy for its total costs. The wholesale cost for contestable customers is the efficient wholesale costs, reflecting the fact that contestable customers have a choice of supplier.

5.1.2 Cost-based or market-based?

The efficient wholesale cost faced by retailers can be estimated by looking at costs or by looking at prices:

- Cost-based approach: efficient wholesale costs are assessed on the basis of the resource costs involved in the supply of electricity. This is measured as the total electricity supply cost of an efficient mix of generation plant to meet the required load. This approach provides an estimate of the LRMC of generation to meet the required load.
- Market-based approach: efficient wholesale costs are assessed on the basis of market prices, including spot prices and contract prices. This is measured as the total cost of an efficient wholesale purchasing strategy to meet the required load.

For the purposes of estimating wholesale costs for this review, we have adopted a cost-based approach. We consider that this approach is most appropriate to the Western Australian market. We also consider that this approach received the most support from stakeholders during the public consultation process. Finally, the lack of available data on market prices and contract positions makes it difficult to estimate wholesale costs using a market-based approach in a robust way.

Relationship between costs and prices

In an efficient market, a cost-based and a market-based approach to estimating wholesale costs will tend to provide similar estimates of wholesale costs over the long run. The reason is that market prices in efficient markets will tend to reflect the resource costs associated with electricity supply.

Even in efficient markets, of course, wholesale costs estimated under the two approaches may differ in the short term. In particular, a market-based approach will provide estimates of wholesale costs that are more dependent on market conditions such as scarcity and competition. The likely result is that market-based

estimates of wholesale costs will vary more significantly from year to year than cost-based estimates of wholesale costs, and also that market-based estimates of wholesale costs will be subject to greater forecasting error. Where regulated tariffs are to be set over several years, this suggests that a cost-based approach will provide greater regulatory certainty. This has been recognised in other jurisdictions: in NSW, where a market-based approach was used to estimate wholesale costs over a three-year regulatory period, the Independent Pricing and Regulatory Tribunal (IPART) undertakes annual reviews of the wholesale cost component of regulated tariffs.

A cost-based approach is appropriate to Western Australia because the generation market is very concentrated. In the current capacity year, Verve Energy is supplying 66 per cent of the capacity credits available to the market.[7] Verve Energy's share of the generation market will decline over the next few years as new plant is built – particularly due to significant investment by Griffin Energy and NewGen – but the market will remain concentrated. In a concentrated market, prices are likely to be in excess of costs. The design of the Western Australian market will mitigate against this to some extent – with an administered price for capacity and a requirement for generators to bid into the Short Term Energy Market (STEM) at short-run marginal cost – but prices of bilateral contracts are nevertheless likely to reflect this level of concentration. Because of this, and until the Western Australian market transitions to a more competitive structure, we consider that a cost-based approach to estimating wholesale costs is more appropriate.

The implication of adopting a cost-based approach in Western Australia is that we are implicitly modelling a cost that reflects a bundle of energy and capacity. That is, we are not separately modelling the cost of supplying capacity through the capacity market and the cost of supplying energy through the energy market. Rather we are modelling the cost of the mix of generation to meet the required load. With efficiently operating energy markets and capacity markets, over the long term this cost will reflect price outcomes in the energy market and the capacity market.

Public consultation

During the course of public consultation undertaken during this review, key stakeholders and the broader public were invited to provide views on the approach to estimating wholesale costs. While different submissions were put forward, we consider that a cost-based approach received the most support from stakeholders.

Among those stakeholders that supported a cost-based approach, a key reason for this was the difficulty of getting appropriate market price signals in the Western Australian market. For instance, Alinta commented that it considers the Western Australian electricity market is not mature enough to warrant a market-based approach to costing wholesale electricity. Alinta noted that electricity

[7] IMO, *2008 Statement of Opportunities Report*, July 2008, page 17..

traded through the STEM only accounts for a small volume of overall wholesale transactions, and it would be difficult to obtain accurate data on bilateral wholesale contracts. Synergy commented that there is no clear benchmark for setting market-based prices in the Western Australia electricity market: the STEM price suffers from a lack of liquidity, restrictions on bidding behaviour and price caps; the reserve capacity price is based on peaking plant; and the vesting price is based on regulated retail and network tariffs. Simcoa commented that it believes that there is not yet an efficient mix of contracts to use as a basis for a market-based approach.

This is not to say that there was no support for adopting the market-based approach. For instance, Verve Energy commented that the market-based approach is most appropriate because it is likely to best reflect the most efficient costs achievable by generators, given all relevant commercial factors. Synergy recommended a hybrid approach that combines elements of the cost-based and market-based approach. The Independent Market Operator (IMO) commented that a consideration of both cost and price would be pragmatic.

Data issues

During the course of consultation undertaken during this review, the OOE released a Data Request to key stakeholders. As part of this Data Request, businesses were asked to provide information on current and forecast prices for energy – including spot prices and contract prices, and contract positions. However, in responses to the Data Request, businesses did not provide any data on prices or contracts.

In part, the lack of response to the request for current and forecast prices reflects the current state of the Western Australian market. With the WEM being only recently established, there is little experience on which to forecast prices. There is also no transparent source of contract prices. More importantly, key stakeholders commented that there have been very few contracts offered in the WEM at this stage.

In the absence of a transparent source of information on current and future contract prices, or information on contract positions, we consider that adopting a cost-based approach to estimating wholesale costs is the more robust approach.

5.1.3 Greenfields or brownfields LRMC?

In estimating the LRMC of electricity supply, existing generation plant in the system can be treated in different ways:

- Greenfields LRMC – this approach assumes that there is currently no plant available to serve the required load and that the required load must be met with new generation plant. This approach effectively builds, and prices, a whole new generation system that is least cost. This approach has the effect of re-pricing all existing capacity at efficient levels.
- Brownfields LRMC – this approach assumes that the existing mix of generation plant in the system is in place and that the required load can be met using both existing generation plant and new generation plant. This

approach seeks to price load on the basis of the least cost way of adding to the existing stock of plant.

Importantly, in estimating LRMC, the capital costs of existing and committed plant are treated as sunk and therefore irrelevant to future decision-making. In deciding whether to run existing plant, only variable costs are taken into account. In contrast, the capital costs of new plant are relevant to decision-making, since these costs are not sunk. In deciding whether to run new plant, therefore, both capital costs and variable costs are taken into account. Under a greenfields approach, there is no existing or committed plant and therefore no capital costs are treated as sunk.

For the purposes of estimating wholesale costs for this review, we have adopted a greenfields approach. We consider that this is more appropriate in the context of the Western Australian market.

One of the key drivers of differences between a greenfields LRMC and a brownfields LRMC is the requirement for new capacity in the system. Because investments in generation plant are lumpy, generation systems are typically characterised by variations from year to year in the relationship between forecast load and available capacity. Following significant investments in new plant, an estimate of brownfields LRMC will typically fail to reflect the fact that new investment is not required. As capacity becomes scarcer, an estimate of brownfields LRMC will increase to reflect the fact that new investment is required. On the other hand, an estimate of greenfields LRMC will not be subject to these variations, because under a greenfields approach a new set of generation is conceptually built to meet required load each year.

In the SWIS there is reason to expect that variations from year to year in the relationship between forecast load and available capacity will be significant. One reason is the relatively small size of the SWIS: generation plant tends to be built in particular block sizes, so that any investment in new plant in the SWIS is likely to have a bigger impact on the relationship between forecast load and available capacity in the SWIS than an equivalent investment in a larger market. Furthermore, the market in Western Australia is undergoing significant reform, including the facilitation of entry by new generators and retailers, and restrictions on investment in new plant by Verve Energy. This is likely to lead to more active investment in the SWIS over the near term (as, in fact, has been observed). While there is significant investment in new generation capacity in the SWIS over the next few years, it is not clear that outcomes in the next few years reflect longer-term trends.

Within this context, there is reason to expect that a brownfields LRMC will vary materially from year to year. In particular, over the period up to 2011/12 the evidence suggests that there will be excess capacity in the SWIS. This will cause a brownfields LRMC to be low over this period. However, once demand growth and plant retirement result in a need for new generation investment, the brownfields LRMC will increase significantly. The implication is that adopting this approach to determine regulated tariffs in the SWIS would create a situation in which tariffs could vary materially from year to year.

5BAllowance for black wholesale costs

On the other hand, a greenfields LRMC will be more stable over time. In each year, a greenfields LRMC will reflect the requirement, over the long-term, to fund new investment. In the interests of stable regulated tariffs, and providing a return on capital over the long-term, we consider that the greenfields LRMC is more appropriate.

5.1.4 Conclusion on approach

In order to reflect the arrangements under the Vesting Contract, and how those arrangements affect the supply of electricity to non-contestable customers, we have adopted a different approach to estimating wholesale costs for contestable and non-contestable tariffs:

- For those tariffs for which a majority of customers are below the contestability threshold (the A1, K1, new L1 and R1 tariffs), black wholesale costs are estimated as a blend of greenfields LRMC and Verve Energy's sustainable price.[8]
- For those tariffs for which a majority of customers are above the contestability threshold (the new L3, M1, R3, S1, T1 and W1 tariffs), black wholesale costs are estimated as greenfields LRMC.[9]

It is worth reiterating that this approach results in an estimate of wholesale costs that includes both the costs of capacity and the costs of energy. Verve Energy's sustainable energy price includes the costs that Verve Energy faces in providing capacity to the market and the costs that Verve Energy faces in providing energy to the market. The greenfields LRMC also includes both the costs of investing in generation capacity as well as the operating costs of generation. In this regard, the approach reflects the costs that retailers face in the market for capacity and the market for energy.

5.2 ESTIMATING VERVE ENERGY'S SUSTAINABLE ENERGY PRICE

Verve Energy's sustainable energy price is the price that Verve Energy needs to be a sustainable business, earning enough revenue to cover operating costs, an appropriate rate of return on assets and tax payable. This section sets out the estimate of Verve Energy's sustainable price.

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[8] The exception is the B1 tariff. While customers on the B1 tariff are below the contestability threshold, determining a wholesale cost for the B1 tariff simply as the greenfields LRMC seems more appropriate. The reason is that the B1 tariff is an off-peak tariff, with a load profile that is very different from that of other non-contestable tariffs and also from Verve Energy's total load. For this reason, Verve Energy's sustainable energy price is unlikely to be a good reflection of the cost to serve the small number of customers on the B1 tariff. Wholesale costs for the B1 tariff are discussed in Section 10.

[9] No load shape was available for streetlight tariffs. As a result, the wholesale costs for streetlight tariffs cannot be estimated in the same way as for other tariffs. The wholesale costs for streetlight tariffs are discussed separately in Section 10.

5.2.1 Key inputs

The cost estimates used to calculate Verve Energy's sustainable price are based on data provided by Verve Energy on a confidential basis. Frontier Economics has not audited the data provided by Verve Energy.

The sustainable energy price is based on forecasts of the costs, revenues and load of Verve Energy each year over the period to 2011/12. Key inputs that drive the result include:

- Verve Energy's forecast of operational expenditure.
- Verve Energy's required return on assets, which is based on forecast asset values, and a pre-tax weighted average cost of capital (WACC). While we have not independently calculated an appropriate WACC, the Verve Energy WACC is within the range of what we would expect.
- Verve Energy's forecast of revenue from sources other than electricity sales.
- Verve Energy's forecast electricity sales.

5.2.2 Methodology and results

The first step in estimating the sustainable energy price is to estimate Verve Energy's target sustainable revenue. In order for Verve Energy to operate sustainably, it will need to recover this revenue.

Verve Energy's target sustainable revenue is calculated on the basis of the expenditure forecasts provided by Verve Energy. The target sustainable revenue includes operational expenditure, including fuel costs, labour costs, purchases, other expenses, etc. The target sustainable revenue also includes a return on total assets (calculated on the basis of a pre-tax WACC). The target sustainable revenue does not include a separate line item for tax payable, since the return on total assets is estimated on the basis of a pre-tax WACC, and does not include separate line items for interest, since this is implicitly included in the return on total assets.

The second step is to estimate the amount of Verve Energy's target sustainable revenue that must be recovered from electricity sales. Verve Energy has several sources of revenue other than electricity sales. In order to estimate the sustainable energy price, these other sources of revenue must be deducted from the target sustainable revenue. The following revenues are excluded:

- revenues from trading in environmental energy products;
- revenues from ancillary services;
- revenues earned in other markets; and
- revenues earned from fuel trading activities.

Deducting the revenues that Verve Energy forecasts it will earn from other activities from the target sustainable revenue provides an estimate of the revenue that Verve Energy needs to recover from electricity sales.

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The final step in estimating Verve Energy's sustainable energy price is to convert the revenue requirement from electricity sales into an estimate of the sustainable energy price. The required revenue from electricity sales is divided by forecast electricity sales, providing an average price per unit of energy that is needed to recover the required revenue.

Because much of the information on which Verve Energy's sustainable energy price is calculated is confidential, the sustainable energy price cannot be included in this public report.

5.3 ESTIMATING BLACK WHOLESALE LRMC

Frontier Economics has developed an electricity market model – *WHIRLYGIG* – that can be used to determine the total electricity supply cost of an efficient mix of generation plant to meet a particular load. This model is used to determine the LRMC for each regulated tariff.

5.3.1 Modelling approach

WHIRLYGIG is a mixed integer linear programming model. The model is used to optimise investment and dispatch decisions in electricity markets. Specifically, the model seeks to minimise the total cost (including fixed and variable costs) of meeting electricity demand, subject to a number of constraints. These constraints include that:

- supply must exactly meet demand at all times;
- minimum reserve requirements must be met;
- generators cannot run more than their physical capacity factors;
- some generators must run for specified periods; and
- additional policy constraints, including greenhouse policies, are met.

WHIRLYGIG essentially chooses from an array of investment and dispatch options over time, ensuring that the choice of investment and dispatch options is least-cost. The model can be used to separately identify black wholesale costs and green wholesale costs.

It is worth thinking about what dispatch means in the context of modelling LRMC using *WHIRLYGIG*. *WHIRLYGIG* determines the least cost mix of generation plant and the least cost operation of that plant to meet the half-hourly load profile of a particular load shape. So, the cost that *WHIRLYGIG* determines includes the operating costs of running generation plant to meet the load in each half-hourly interval in the year.

5.3.2 Modelling inputs

As part of the Data Request the OOE released to key stakeholders, input on key modelling assumptions was requested from the businesses. Where appropriate, the data provided in response to the Data Request has been used in the wholesale cost modelling. The key modelling assumptions are set out in the sections that

follow. Because much of the information provided by the businesses is confidential, full details of assumptions cannot be provided in every case.

Load profile

A key determinant of the LRMC for a particular regulated tariff is the load profile of consumption under that tariff. A flatter load is cheaper to supply because less peaking plant is required to meet the load. This means that the stock of generation plant to meet the load is run more often throughout the year, reducing the average cost.

Since the load profile for consumption under each of the regulated tariffs is different, there are different LRMCs for each regulated tariff. Wholesale costs are calculated for each regulated tariff on the basis of load data provided by Synergy. Since this load data is confidential, details are not provided in this report.

In modelling the LRMC of the regulated tariffs, each of the regulated loads can be modelled on a stand-alone basis, or they can be modelled in aggregate.

Under the stand-alone approach, the LRMC of a mix of generation to individually supply each regulated tariff is modelled. This provides an estimate of the cost that a retailer would face if the retailer were only to supply the load under that tariff.

Under the aggregate approach, the LRMC of a mix of generation to meet the aggregate load across all regulated tariffs is modelled. That is, under this approach, the LRMC reflects the cost of building and operating a mix of new entrant plant to provide energy to meet the combined half-hourly load shape of all tariffs. Having determined the cost of meeting this combined half-hourly load shape, the total cost is then allocated to individual tariffs on the basis of the load shape of these tariffs. Effectively, the approach is to estimate the frequency with which costs occur and to allocate costs on the basis of the load shape of individual tariffs.

In modelling the LRMC, we have adopted the aggregate approach. The aggregate approach is a more realistic reflection of the costs that retailers face, since retailers are able to purchase electricity to meet their entire load rather than purchasing electricity individually to meet each individual tariff load. So, to the extent that there are complementarities arising from the combination of the individual tariff load shapes (because, for instance, the peak loads for the individual tariffs are not perfectly coincident), these are captured in the aggregate approach.

The exception to the use of this approach is the W1 tariff. Because the W1 tariff is modelled as a flat load, the allocation of total costs under the aggregate approach does not provide an appropriate estimate of the costs of supplying the W1 tariff. For this reason, the LRMC of the W1 tariff is modelled using the stand-alone approach.

Reserve margin

In modelling the aggregate demand for regulated tariffs, a margin over total load is added to reflect the reserve margin required in the WEM.

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The reserve margin required in the WEM was previously based, to a large extent, on the size of the largest generating unit in the system. However, this criterion was recently amended through a rule change proposal submitted by the IMO.[10] The IMO has submitted that, because the size of the largest generating unit may not change for some years, it is likely that the reserve margin will decrease, as a proportion of total load, as the maximum demand on the system grows. The IMO therefore proposed that the reserve margin be set at the larger of the largest unit size or a defined percentage of the forecast maximum demand. The IMO proposed that the defined percentage be a reserve margin of 8.2 per cent. This percentage revenue margin was based on a study undertaken by CRA International and input from Market Participants and other interested parties.

This rule change proposal took effect on 10 April 2008, and a reserve margin of 8.2 per cent has been incorporated in our modelling. While the Wholesale Electricity Market Rules provide a more detailed set of criteria for determining the reserve margin in any year, the impact of these additional criteria on the required reserve margin is likely to be minor.

Demand assumptions

To streamline the modelling process, the analysis focuses on 30 representative demand points per year rather than a chronological modelling of each half-hour in each year. Each demand point is weighted by its expected frequency of occurrence during the year, so that yearly average results can be determined by adding the frequency-weighted outcomes for each demand point. As a result, the points of low and average demand, which occur frequently throughout the year, receive a higher weighting than the peak demand points, which occur infrequently. The resolution of demand points has been skewed towards the peak end of the load duration curve as market outcomes at times of high demand tend to drive outcomes in electricity markets.

Generation assumptions – new plant

To model the cost of generation plant to meet the aggregate load shape of regulated tariffs (including the required reserve margin) it is necessary to include inputs relating to a mix of possible new generation plant. Based on the costs and operating parameters of these possible new generation plants, *WHIRLYGIG* defines the mix of investment and operation to meet the aggregate load shape at least total cost.

Five plant options are included in the model: a coal-fired generator, an open cycle gas turbine (OCGT), a closed cycle gas turbine (CCGT) and two high efficiency gas turbines. OCGT plants have the option of operating on gas or liquid fuel. In the event of constraints on the gas network, or localised constraints on the electricity network, peaking plant may operate on liquid fuel rather than gas. This has been incorporated into the design of the Wholesale Electricity Market in Western Australia. The modelling finds that there are times where it is more

[10] IMO, *SWIS Reliability Planning Criteria*, Final Market Rule Change Report, 9 April 2008.

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economic to run these OCGT on liquid fuel where there are network constraints or because of the high cost of low load factor gas contracts. The annual capacity factors of these liquid plants tend to be less than 5 per cent.

A range of renewable energy options are also included in modelling work undertaken to estimate green wholesale costs, as discussed in Section 6. The cost of these renewable options is incorporated into the estimate of green wholesale costs.

There are two key cost assumptions for generation plant that drive modelling results: capital costs and fuel costs.

There are several sources for these capital cost assumptions:

- The capital cost assumptions for the OCGT come from the IMO's assessment of capital costs of an OCGT for the purposes of determining Maximum Reserve Capacity Price.[11]
- The capital cost assumptions for the CCGT and the coal-fired generator were based on the capital cost assumptions for the OCGT, but scaled up to retain the relative capital costs between coal-fired generators, CCGT and OCGT included in ACIL Tasman's report on generator costs in the NEM.[12] This reflects the higher capital costs that are evident in Western Australia, and which are reflected in the IMO's assessment of the capital costs of an OCGT in Western Australia, in the capital costs of both CCGT and coal-fired generators in Western Australia.
- The capital cost assumptions for the two types of plant were provided by Verve Energy on a confidential basis in response to the Office of Energy's data request.

Capital cost assumptions are set out in Table 1. The confidential capital cost assumptions provided by Verve Energy are not included in this table.

Generator type	*Capital cost*	*Source*
Coal-fired generator	$2826/kW	IMO and ACIL Tasman
CCGT	$1512/kW	IMO and ACIL Tasman
OCGT	$995/kW	IMO

Table 1: New generation plant - capital cost assumptions (real 2007/08)

Fuel cost assumptions also come from different sources:

[11] IMO, *Maximum Reserve Capacity Price for the 2010/11 Reserve Capacity Year*, Final Report, December 2007.

[12] ACIL Tasman, *Fuel Resource, new entry and generation costs in the NEM*, Report 2 – Data and documentation, 27 March 2007.

5BAllowance for black wholesale costs

- Coal price assumptions are derived from responses to the OOE's data request. Given that coal price forecasts provided by the businesses are confidential and commercially sensitive, they are not set out in this report. However, some indication of the nature of the forecasts can be provided. In the first instance, it is notable that each of the forecast prices that were provided varied over the period to 2011/12, and that forecasts followed different trends over this period. For each forecast, however, prices trended downwards over the last few years of the period to 2011/12. It is also notable that the forecast prices provided varied in magnitude.

  In developing the coal price inputs adopted for the modelling, we took into account the forecasts provided by the businesses, but were also mindful of the relationship between coal prices and gas prices. In particular, given that there is likely to be a degree of interaction between coal prices and gas prices, we have adopted coal price inputs that are consistent with investment in, and dispatch of, coal-fired generation plant in the SWIS. We consider that this is appropriate given that coal producers are likely to attempt to shadow the price of gas in an environment in which gas prices have recently increased, but will be constrained in their ability to increase coal prices by the price of gas.

- Gas price assumptions are derived from publicly available information. Much of this information was set out in the Office of Energy's Issues Paper. For instance, during the middle of 2007, the ERA[13] reported that domestic gas prices for new contracts are around $5.50 to $6.00 per GJ, and EnergyQuest[14] reported that domestic gas prices for new contracts were over $5.00 per GJ. Argonaut Securities[15] has forecast that gas prices will spike to $7.00 to $10.00 per GJ in 2009 before falling back to $5.00 to $7.00 per GJ in 2011. Reports of particular contracts also suggest that prices in Western Australia have increased. For instance, Santos[16] reports that contracts for gas supply to the domestic market in Western Australia over 2007 were priced in the range of $5.00 to $6.00 per GJ. Media reports suggest that during 2007 Santos signed gas supply contracts with Barrick Gold Corporation at $7.53 per GJ,[17] with Jabiru Metals at $4.71 per GJ[18] and with Newmont Mining at $5.50 per GJ.[19] Based on these sources of information we have assumed that the market price for gas in the SWIS over the period to 2011/12 is $8.00 per GJ delivered. We have assumed that the price of gas remains constant in real

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[13] Lyndon Rowe, *Gas Issues in Western Australia*, Presentation to the Australian Institute of Energy, 13 June 2007.

[14] EnergyQuest, *Energy Quarterly*, May 2007.

[15] Argonaut Securities, *The Western Australian Gas Market*, September 2007.

[16] Santos presentation, *Value in the Energy Sector*, UBS Resources Conference, 27 June 2007.

[17] Gas Gazette, *Santos Wins in the West*, Edition 23, 11 July 2007.

[18] Gas Gazette, *Santos Wins in the West*, Edition 23, 11 July 2007.

[19] Citigroup, *Santos Ltd*, Company In-Depth, 30 March 2007.

5BAllowance for black wholesale costs

terms, because there is currently little certainty about gas price movements over the period to 2011/12.

- In regard to OCGT plants operating on liquid fuel, we have assumed a price of $30/GJ.

5.3.3 Results – black energy LRMC

Based on the modelling approach and modelling inputs discussed, the black wholesale LRMC for each tariff for each year over the period 2008/09 to 2011/12 is set out in Table 2. Note that, for contestable customers, these costs are not weighted with the Verve Energy sustainable energy price.

Regulated tariff	2008/09	2009/10	2010/11	2011/12
A1 tariff	$102.95	$106.16	$99.14	$97.77
K1 tariff	$101.61	$104.77	$97.85	$96.49
L1 tariff *	$100.46	$103.56	$96.75	$95.40
L3 tariff *	$100.46	$103.56	$96.75	$95.40
M1 tariff	$102.17	$105.35	$98.38	$97.02
R1 tariff **	$102.47	$105.66	$98.67	$97.31
R3 tariff **	$102.47	$105.66	$98.67	$97.31
S1 tariff	$100.73	$103.84	$97.00	$95.65
T1 tariff	$101.63	$104.78	$97.87	$96.51
W1 tariff	$77.45	$81.68	$72.58	$70.88

Table 2: Black energy greenfields LRMC ($/MWh, real 2007/08, excluding network losses)

Note: Black wholesale costs for the B1 tariff and streetlight tariffs are discussed in Section 10.

** Since there are currently no separate L1 and L3 tariffs, there is no separate load data for these tariffs. As a result, in estimating the LRMC for the L1 and L3 tariffs, the load profile for the existing L1 tariff is used.*

*** No load data has been provided for the existing R1 and R3 tariffs because these tariffs have only been active since 1 July 2007. In estimating the LRMC for the R1 and R3 tariff, the load profile for the old R1 tariff is used.*

5.4 CONCLUSION ON BLACK WHOLESALE COST

For non-contestable tariffs, the black wholesale cost is a weighted average of the Verve Energy sustainable energy price and the black LRMC for each tariff. The Verve Energy sustainable energy price and the black LRMC are weighted

according to, respectively, Verve Energy's Vesting Contract capacity obligation and the displacement of the capacity cap under the Vesting Contract. Since the release of Frontier Economics' draft recommendations report, the Office of Energy has revised its view of the likely extent of displacement by 2011/12. As a result, the black wholesale costs for non-contestable customers in 2011/12 in this report differ slightly from the costs in the draft recommendations report. For contestable customers, the black wholesale cost is the black LRMC.

The black wholesale component of each tariff for each year over the period 2008/09 to 2011/12 is set out in Table 3.

Regulated tariff	2008/09	2009/10	2010/11	2011/12
A1 tariff	$89.31	$90.42	$91.47	$88.94
K1 tariff	$89.21	$90.27	$91.27	$88.49
L1 tariff	$89.13	$90.14	$91.09	$88.10
L3 tariff	$100.46	$103.56	$96.75	$95.40
M1 tariff	$102.17	$105.35	$98.38	$97.02
R1 tariff	$89.27	$90.36	$91.39	$88.78
R3 tariff	$102.47	$105.66	$98.67	$97.31
S1 tariff	$100.73	$103.84	$97.00	$95.65
T1 tariff	$101.63	$104.78	$97.87	$96.51
W1 tariff	$77.45	$81.68	$72.58	$70.88

Table 3: Black wholesale costs ($/MWh, real 2007/08, excluding network losses)

Note: Black wholesale costs for the B1 tariff and streetlight tariffs are discussed in Section 10.

5BAllowance for black wholesale costs

6 Allowance for green wholesale costs

The cost of green energy is the additional cost of complying with greenhouse gas emissions mitigation policies.

There are two key greenhouse polices that are likely to impose additional costs in Western Australia over the period to 2011/12:

- Emissions trading: the Federal Government is committed to introducing a national emissions trading system (ETS) to start by no later than 2010.
- Renewable energy targets: both the Western Australia Government and the Federal Government are committed to having renewable energy targets in place during the review period.

The costs of complying with these greenhouse policies are modelled using the same approach as the black wholesale costs were modelled: that is, costs are modelled on the basis of the resource costs required for generators and retailers in the SWIS to comply with these schemes. However, because these schemes will operate on a national basis, the modelling approach will need to take this into account.

6.1 OVERVIEW OF GREENHOUSE POLICIES

Before setting out the modelling approach for estimating the costs of complying with a national ETS and applicable renewable energy targets, it is useful to first set out the current state of policy in regard to these mechanisms.

6.1.1 National ETS

The Federal Government has committed to introducing an ETS to start by no later than 2010, with the detailed design of the ETS to be finalised by no later than 2008. While the Federal Government has not yet set any short or medium term targets for the ETS, it has announced a long-term target of reducing emissions by 60 per cent by 2050.

Key decisions regarding the design of a national ETS will be informed by the Garnaut Climate Change Review (Garnaut Review). The Garnaut Review was commissioned in April 2007 by the Labor State Governments. Following Labor's victory at the Federal election in late 2007, the Prime Minister has since confirmed Federal participation in the review. The Garnaut Review released an Interim Report in February 2008,[20] but stressed that many of the views included in that report were genuinely interim views. The Interim Report included some discussion of the design of an ETS, but little detail at this stage. The Interim Report did not provide any detail on short term and medium term emissions targets to reach the Federal Government's long-term target of a 60 per cent reduction on 2000 levels by 2050.

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[20] Garnaut Climate Change Review, *Interim Report to the Commonwealth, State and Territory Governments of Australia*, February 2008.

6.1.2 Renewable energy target

The Commonwealth Mandatory Renewable Energy Target (MRET) has been in operation since 2001. In its existing form, MRET requires that 9,500 GWh per annum of additional electricity be produced from renewable energy in Australia by 2010.

The Federal Government has recently announced that the MRET scheme will be expanded to ensure that 20 per cent of Australia's electricity supply is from renewable energy by 2020. The Government has committed to expanding the MRET target from 9,500 GWh per annum to 45,000 GWh per annum.

At the Council of Australian Governments (COAG) meeting in December 2007, the Federal and State Governments agreed to work cooperatively, commencing in early 2008, to bring the existing MRET scheme and the various state-based schemes into the expanded MRET target of 45,000 GWh per annum.

6.2 MODELLING THE IMPACT OF GREENHOUSE POLICIES

Emissions trading and renewable energy targets operate in different ways:

- An ETS operates by imposing an obligation on liable parties (principally electricity generators) to surrender carbon credits to meet their levels of emissions. Each carbon credit represents a given amount of emissions. These carbon credits will have a market price, determined by the supply and demand of credits.
- MRET operates by imposing an obligation on liable parties (principally electricity retailers) to surrender renewable energy certificates (RECs) to meet their share of the renewable energy target. Each REC represents a given amount of renewable energy generation. RECs have a market price, determined by the supply and demand of RECs.

6.2.1 Modelling approach

While the schemes operate in different ways, they can both be modelled using the same basic framework.

In the first instance, it is important to recognise that both a national ETS and the expanded MRET are national in scope. As a result, prices for RECs and for carbon credits will be determined in a national market, and there will be a single national price for these instruments. This national price will reflect demand and supply conditions across Australia, rather than the demand and supply conditions unique to Western Australia. For this reason, our approach is to model the costs of meeting these schemes in the NEM, which is by far the largest market in Australia, and accounts for a large majority of the electricity generated and consumed in Australia. Other regions – including Western Australia – are assumed to be price takers in the market for RECs and carbon credits.

To be consistent with the approach to estimating black wholesale costs, green wholesale costs are estimated using a cost-based approach. Under this approach,

the task is effectively to determine the resource costs of meeting the targets under each of the schemes, and then to allocate these total resource costs to liable parties.

Frontier's *WHIRLYGIG* model can be used to determine the resource costs of meeting the targets under a national ETS and the expanded MRET.

6.2.2 Modelling assumption

For the purposes of estimating the resource costs of complying with a national ETS and the expanded MRET, *WHIRLYGIG* is used in the same way that is was used to estimate black wholesale costs in the SWIS. The key differences in approach is that the model is constrained so that it chooses investment and dispatch options that comply with the targets under a national ETS and the expanded MRET, and input assumptions are chosen to reflect the NEM rather than the SWIS.

Policy constraints

With regard to estimating the resource costs of complying with a national ETS, the key constraint relevant to our modelling is the emissions target in the scheme. At this stage, the Federal Government has not announced any short-term emissions pathway. The Federal Government has only announced a long-term target of reducing emissions to 60 per cent of 2000 levels by 2050. A short-term emissions pathway has been set out in the proposal for a national ETS from the National Emissions Trading Taskforce (NETT) (which was set up by the State and Territory Governments). In August 2006 the NETT released a discussion paper setting out a possible design for an ETS, including potential emissions pathways. Target 2 in the NETT discussion paper is consistent with a long-term target of reducing emissions to 60 per cent of 2000 levels by 2050 and has therefore been used as the emissions constraint for the purposes of our modelling (adjusted to reflect the share of that pathway for the NEM, to reflect the fact that our modelling focuses on the NEM). We have assumed that a national ETS will be in operation from the beginning of July 2010.

With regard to estimating the resource costs of complying with the expanded MRET, the key constraint relevant to our modelling is the renewable energy target in the scheme. For the purposes of our modelling, the assumed national renewable energy target begins at a level that encompasses all existing renewable energy targets in Australia (including the existing MRET target of 9,500 MWh). This reflects the current requirement, on a national basis, to generate sufficient renewable energy certificates to meet each of the existing targets. From 2010, the assumed national renewable energy target transitions from to 45,000 MWh by 2020 on a straight-line basis. This reflects a likely pathway to the expanded MRET target. The assumed national renewable energy target is set out in Figure 1. This national target is adjusted to reflect the share of total certificates required in the NEM, to reflect the fact that our modelling focuses on the NEM.

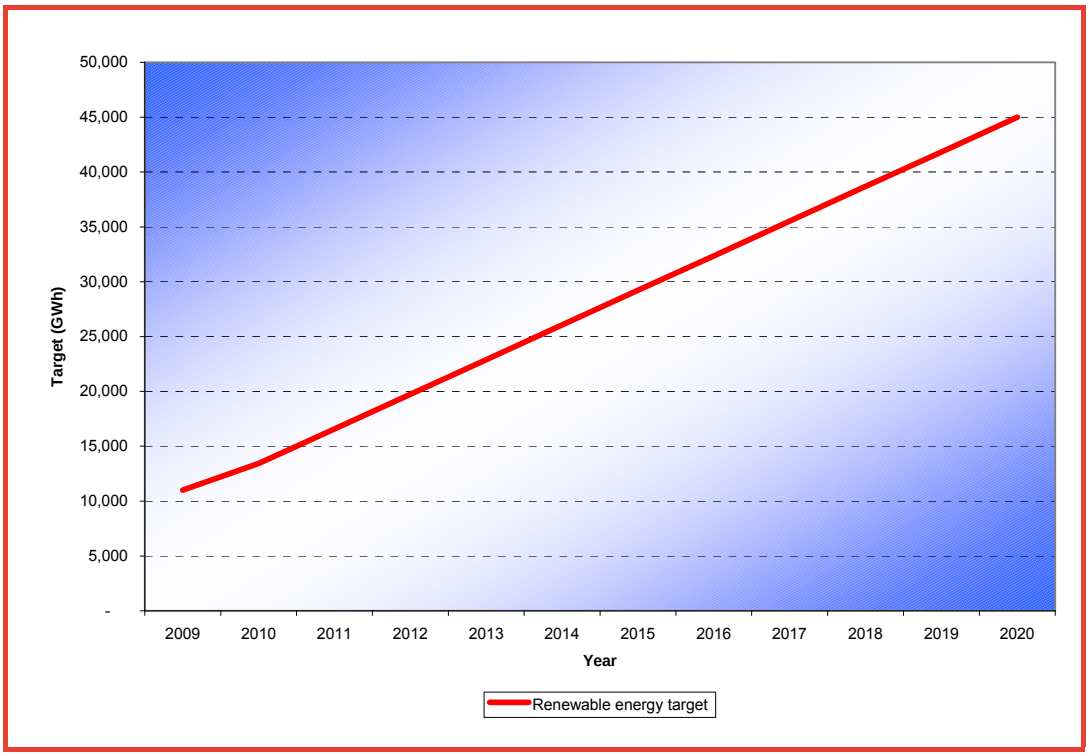

Figure 1: Expanded MRET target

Demand

In modelling the NEM rather than the SWIS, it is clear that different demand assumptions are required. Demand levels for each region in the NEM are input into the model, with a representative sample of demand points used, rather than that full half-hourly load profile. Each demand point was weighted by its expected frequency of occurrence during the year. Demand assumptions were based on medium growth, 50 per cent probability of exceedence forecasts from NEMMCo's Statement of Opportunities.

Regional reserve margins published by NEMMCo were also incorporated in to the model to ensure that reserve levels are achieved in each region in each year.

Generation assumptions – existing plant

Because the costs of complying with greenhouse policies will depend on the operational characteristics of existing plant, modelling green wholesale costs must be undertaken on a brownfields basis. That is, all existing scheduled plant and committed scheduled plant is included in the model.

Input assumptions regarding the characteristics of these plant are derived from a number of sources. Generation capacities are derived from NEMMCo's Statement of Opportunities. Operating costs for existing plant, including fuel costs, are derived from an ACIL Tasman report to NEMMCo on generation

costs.[21] Operating characteristics of these plant are derived from a number of sources, including NEMMCo and Roam Consulting.

Generation assumptions – new plant

Because new generation plant will be required in the NEM over the period to 2011/12, including new renewable plant to meet the expanded MRET target, modelling takes into account a range of options for new investment.

The key input assumptions that drive investment outcomes are operating costs, operating characteristics and capital costs of new plant. Assumptions in regard new plant options are derived principally from ACIL Tasman's report to NEMMCo on generation costs,[22] and an MMA report on the impact of a national ETS.[23]

New renewable plant options include biomass, hydro, geothermal, wind, solar hot water as well as a range of options for generation from waste products. Reflecting the fact that RECs need not be created in the NEM in order for generators in the NEM to be eligible to surrender these RECs, new renewable plant is not constrained to enter particular regions.

6.2.3 Modelling results

The first set of results provided by our modelling of the NEM is a forecast price for both carbon credits and RECs over the period from 2008/09 to 2011/12. The forecast prices for these instruments are set out in Table 4.

	2008/09	2009/10	2010/11	2011/12
Carbon credits ($/credit)	0.00	0.00	24.87	26.68
RECs ($/REC)	24.17	25.93	27.82	29.86

Table 4: Forecast prices for carbon credits and RECs (real 2007/08)

In order to determine an allowance for the costs of complying with a national ETS and an expanded MRET, it is then necessary to determine how these prices will impact on the cost of wholesale energy in the SWIS.

For the national ETS, the impact on the cost of wholesale energy in the SWIS is determined by the carbon intensity of generation in the SWIS. It is the carbon intensity of generation that determines the number of carbon credits that will be required by generators in the SWIS and, ultimately, the impact of the national

[21] ACIL Tasman, *Fuel Resource, new entry and generation costs in the NEM*, March 2007.

[22] ACIL Tasman, *Fuel Resource, new entry and generation costs in the NEM*, March 2007.

[23] MMA, *Impacts of a National Emissions Trading Scheme on Australia's Electricity Markets*, July 2006.

ETS on the price of wholesale energy in the SWIS. Implicit in this approach is the assumption that for each tariff, a mix of generation plant that reflects the mix of generation plant in the SWIS will be used to meet the required load.

Since the carbon intensity of generation in the SWIS is determined by the operation of existing plant in the SWIS, the forecast carbon intensity to 2011/12 is determined by using *WHIRLYGIG* to model investment and dispatch to 2011/12 on a brownfields basis (that is, taking into account all existing and committed generation in the SWIS). For the purposes of this modelling, the same assumptions were used as for modelling the black wholesale cost in the SWIS, with two exceptions:

- Forecast load: since the brownfields approach takes into account the existing mix of plant in the SWIS, this approach also has to take into account the total load that this existing mix of plant is designed to serve. To estimate the half-hourly load shape for the SWIS as a whole we scaled up the combined half-hourly load shape for all the gazetted tariffs as well as those contract customers for whom load data was provided by Synergy (providing a load shape that reflects a mix of customers) to match the total annual energy forecasts for the SWIS set out in the IMO's Statement of Opportunities. In scaling the load shape, the peak demand was also scaled to match the peak energy forecast for the SWIS set out in the IMO's Statement of Opportunities.
- Existing and committed generation plant: to model the operation of existing and committed generation plant, it is necessary to have inputs in relation to plant characteristics and operating costs. This information was drawn largely from responses to the OOE's Data Request. Where there were gaps in the required data, information was drawn from the IMO or from consideration of other comparable plant.

Based on the modelling of the dispatch of the existing and committed generation plant (and any new plant required to meet forecast load) the emissions intensity of generation in the SWIS is forecast as set out in Table 10. The increase in the emissions intensity in the SWIS from 2010/11 reflects a greater proportion of generation from coal-fired plant. This, in turn, reflects both a change in the mix of installed generation plant in the SWIS (particularly due to the commissioning of new coal-fired plant) as well as a change in the relative cost of coal and gas over the period.

	2008/09	2009/10	2010/11	2011/12
Emissions intensity (tCO2/MWh)	0.76	0.76	0.80	0.80

Table 5: Emissions intensity of generation in the SWIS

6BAllowance for green wholesale costs

Based on these forecast emissions intensities, and the forecast prices for carbon credits, the estimated cost in the SWIS of meeting obligations under a national ETS are set out in Table 6.

	2008/09	2009/10	2010/11	2011/12
ETS cost ($/MWh)	0.00	0.00	19.82	21.23

Table 6: Cost allowance for complying with a national ETS (real 2007/08, excluding network losses)

For the expanded MRET, the impact on the cost of wholesale energy in the SWIS is determined by the renewable power percentage for the SWIS. The renewable power percentage is the proportion of SWIS load that must come from renewable sources, and is determined by reference to the contribution that generation in the SWIS must make to the MRET target. Based on the assumed pathway for the expanded MRET target the renewable power percentage for the SWIS is set out in Table 7.

	2008/09	2009/10	2010/11	2011/12
Renewable power percentage	3.2 %	3.7 %	5.2 %	6.5 %

Table 7: Renewable power percentage for the SWIS

Based on these renewable power percentages, and the forecast prices for RECs, the estimated cost in the SWIS of meeting obligations under the expanded MRET are set out in Table 8.

	2008/09	2009/10	2010/11	2011/12
MRET cost ($/MWh)	0.78	0.97	1.44	1.95

Table 8: Cost allowance for complying with an expanded MRET (real 2007/08, excluding network losses)

6BAllowance for green wholesale costs

7 Allowance for market fees and ancillary services

The allowances for wholesale costs estimated in Section 5 and Section 6 relate simply to the efficient provision of wholesale energy and capacity to meet each of the tariff loads. In addition to these costs, there are other costs associated with operating in the WEM. These include market fees and fees for ancillary services.

7.1 MARKET FEES

Market fees include the recovery of the operating costs of the IMO, System Management and the ERA. There are three market fees that are charged by the IMO:

- The Market Fee Rate is a charge to recover the costs that the IMO faces in providing market operation services, system planning services and market administration services. The Market Fee Rate is a charge per MWh.
- The System Operation Fee is a charge to recover the costs that System Management faces in providing system operation services. The System Operation Fee is a charge per MWh.
- The Regulator Fee rate is a charge to recover the costs of the ERA's monitoring and regulation activities with respect to the WEM. The Regulator Fee is a charge per MWh.

Prior to 30 June each year, the IMO must publish the market fees that are to apply from 1 July. The Market Fee rate for 2007/08 has been set at $0.468/MWh. This is based on the revenue requirements of the IMO, System Management and the ERA as set out in Table 9.

	Revenue requirement	Fee rate
IMO	10,346,000	$0.322/MWh
System Management	4,392,000	$0.137/MWh
ERA	275,000	$0.009/MWh
Total	**15,013,000**	**$0.468/MWh**

Table 9: Market fees (real 2007/08)

Source: IMO website.

In the absence of information on forecast fee rates to 2011/12, or information on forecast revenue requirements to 2011/12, it is difficult to predict how market fees might vary over the period to 2011/12. However, there is reason to expect

that revenue requirements, and therefore market fees, will be relatively stable over time. For this reason, and in the absence of better information, we assume that fee rates will remain constant in real terms over the period to 2011/12.

7.2 ANCILLARY SERVICES

An Ancillary Service is a service that is required to maintain the security and reliability of the power system. In the WEM, ancillary services are defined to include the following services:

- Load following is the service of frequently adjusting the output of generators within a trading interval to match total system generation to total system load.
- Spinning reserve is the service of holding capacity in reserve so that the facility is able supply energy at short notice.
- Load rejection is the service of holding capacity in reserve so that the facility can reduce output or increase consumption at short notice.
- System restart is the ability to start without requiring energy to be supplied from the network to assist in re-starting the SWIS in the event of a system shut-down.
- Dispatch support services are other ancillary services that are needed to maintain security and reliability of the system, including controlling voltage levels in the SWIS.

System Management is responsible for determining the requirements for ancillary services, based upon standards set out in the Wholesale Electricity Market Rules. System Management is also responsible for budgeting for the cost of procuring ancillary services sufficient to meet the ancillary services requirements (although System Management does not fund these costs). Every three years, System Management is required to submit a proposal setting out the costs of undertaking its functions in the WEM (including the costs of procuring ancillary services) to the ERA for approval.

The most recent ancillary services budget proposal from System Management was submitted in November 2006, for the review period from 1 July 2007 to 30 June 2010.[24] The forecasts in this budget proposal were based on approved 2006/07 budget amounts, adjusted for inflation at 4 per cent per annum. The 2006/07 budget amounts, in turn, were based on work undertaken by MMA for the Office of Energy. System Management consider that these original cost estimates remained valid at the time, with the market having only operated for a limited period. The forecasts for ancillary service costs for 2007/08 provided by System Management are set out Table 10.

[24] Western Power, *System Management Allowable Revenue Application*, 30 November 2006.

Load following	$4,992,000
Spinning reserve	$13,000,000
Load rejection	$0
Dispatch support	$0
System restart	$250,000
Total ancillary services	**$18,242,000**

Table 10: Forecast ancillary services costs for 2007/08 (real 2007/08)

Source: Western Power, System Management Allowable Revenue Application, 30 November 2006.

System Management does not fund Ancillary Services. Rather, the IMO recovers the costs of the ancillary services from Market Participants through the wholesale market settlement systems. The IMO allocates the cost of ancillary services between market participants on the following basis:

- The monthly cost of load following is allocated amongst market participants in proportion to the metered load of market participants. Load following costs are not allocated to scheduled generation.
- The monthly cost of spinning reserve is borne by generators in proportion to the deemed risk that the generator imposes on the system.
- The monthly cost for load rejection, dispatch support and system restart are recovered from market customers in proportion to the metered load of market customers.

In reality, whether these costs are initially borne by generators or by retailers, the costs will ultimately be passed on to consumers. Indeed, since these costs are necessary to the secure and reliable supply of electricity, it is appropriate that end-users face these costs. In order to estimate the costs of ancillary services, the forecast ancillary services costs for 2007/08 are converted into costs per unit of energy. Based on the forecast ancillary services costs for 2007/08 set out in Table 10, and the forecast of expected sent-out energy for the SWIS provided in the IMO's 2007 Statement of Opportunities Report,[25] the estimated cost of ancillary services per unit of output is $1.15/MWh for 2007/08.

Given the recent introduction of the WEM and formal arrangements of funding the costs of ancillary services through the market, there is little historic information available on which to base forecasts of future ancillary services costs. Given this, and in the absence of better information, we assume that ancillary services costs remain constant in real terms over the period to 2011/12.

[25] IMO, *2007 Statement of Opportunities Report*, July 2007, Appendix 5.

7BAllowance for market fees and ancillary services

8 Allowance for retail operating costs

Retail operating costs are those costs that retailers incur in serving their customers. Retailing activities include such things as customer service, billing and revenue collection, and energy trading activities.

This section estimates the retail operating costs that a retailer in Western Australia would incur in retailing to customers on regulated tariffs over the period from 2007/08 to 2011/12. Retail operating costs are estimated separately for tariffs that are primarily contestable and tariffs that are primarily non-contestable, because the evidence suggests that costs for these groups of customers are different.

8.1 CATEGORIES OF RETAIL OPERATING COSTS

To estimate retail operating costs, it is first necessary to consider the categories of cost that should be allowed for as retail operating costs in Western Australia. Retail operating costs are generally considered to consist of:

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

These costs reflect the activities that an efficient electricity retailer must undertake in supplying energy to its customers.

In addition, other costs – including depreciation, customer acquistion costs and FRC-related costs – are in some cases included in the allowance for retail operating costs in other jurisdictions. The treatment of these costs is discussed in the sections that follow.

8.2 RETAIL OPERATING COSTS FOR DIFFERENT CUSTOMERS

The Terms of Reference for this review and assessment of tariffs requires consideration of all regulated tariffs. The evidence suggests that retail operating costs vary across different tariff classes. In order to estimate retail operating costs, therefore, it is necessary firstly to identify which groups of customers have similar retail operating costs, and then to match these groups of customers to particular tariffs.

As discussed below, the evidence suggests that small customers – generally speaking, those customers that are below the contestability threshold – have similar retail operating costs. This is reflected in the available evidence from

Western Australia as well as regulatory decisions from other jurisdictions. For this reason, we estimate a single allowance for retail operating costs for all non-contestable customers.

The retail operating costs for non-contestable customers are incorporated into those tariffs for which a majority of customers are below the contestability threshold of 50 MWh per annum: the A1, K1, new L1 and R1 tariffs. These tariffs represent a mix of residential and small business tariffs.

Retail operating costs for contestable customers are separately estimated. The retail operating costs for contestable customers are incorporated into those tariffs for which a majority of customers are above the contestability threshold: the new L3, M1, R3, S1 and T1 tariffs.

Retail operating costs (and retail margin) for the B1, W1 and streetlight tariffs are discussed separately in Section 10.

8.3 RETAIL OPERATING COSTS FOR NON-CONTESTABLE CUSTOMERS

Consistent with the focus on cost reflective tariffs, retail operating costs for non-contestable customers are assessed on the basis of the costs that an efficient retailer would be expected to incur. Given that non-contestable customers can only be supplied by the incumbent retailer, the initial focus is the efficient costs that an incumbent retailer would incur.

However, since FRC may be introduced in Western Australia, it is also important to consider whether new entrant retailers will be able to achieve similar retail operating costs for non-contestable customers. This is also be addressed.

8.3.1 Methodology for determining retail operating costs

Regulators in other jurisdictions have tended to determine an appropriate allowance for retail operating costs using one or both of two approaches: an assessment of the actual retail operating costs of existing retailers; and benchmarking against allowances for retail operating costs in other regulatory decisions.

The relative weight given to these two approaches is driven, in part, by practical considerations. Where regulators have limited access to useful data on actual retail operating costs, or there are concerns about the appropriate allocation of common retail operating costs, benchmarking is typically used as the basis for determining an appropriate allowance for retail operating costs.

Benchmarking is also used because it provides guidance on the efficient costs of retailing.[26] After all, regulators are typically concerned with providing an

[26] See, for instance, ESCOSA, *2007 Review of Retail Electricity Price Path*, Draft Inquiry Report and Draft Price Determination, August 2007, page A-65:

> The Commission observes that, in comparing an actual cost approach to a benchmarking approach, benchmarking is more likely to be consistent with the Commission's statutory objectives of promoting efficiency and providing incentives to reduce costs. The Commission

allowance for retail operating costs that reflects the costs that an efficient retailer would incur. These may not be the same as the actual costs of incumbent retailers. Benchmarking helps ensure that incumbent retailers are neither rewarded for inefficiency nor penalised for efficiency.

In estimating the retail operating costs for non-contestable customers, we consider evidence on actual costs in Western Australia, as well as benchmarks from other jurisdictions, assessed for relevance to Western Australia:

- During the course of public consultation, stakeholders were invited to provide information on retail operating costs for electricity retailers in Western Australia. Synergy provided, on a confidential basis, forecasts of its retail operating costs for 2007/08.
- Regulators in other jurisdictions in Australia regularly estimate retail operating costs for mass market customers for the purposes of retail price determinations.

8.3.2 Synergy's forecast retail operating costs

During the course of public consultation, Synergy provided internal documents in relation to its retail operating costs for 2007/08. Synergy also provided information retail operating costs assumed for the purposes of its tariff modelling. The information provided by Synergy is confidential.

8.3.3 Benchmarking against regulatory allowances

Table 11 provides an overview of the assessment of retail operating costs in regulatory decisions in other jurisdictions in Australia.

therefore intends to place significant weight on its benchmarking analysis. It will have regard to the actual costs of AGL SA only to ensure that the results of the benchmarking produce sensible outcomes, or where benchmarking is itself not reliable (e.g. due to lack of data).

Decision	*State*	*Regulatory period*	*Retail cost per customer (nominal $)*	*Retail cost per customer (2007/08 $)*	*Comments*
IPART (2000)	NSW	Jan 2001 *to* Jun 2004	$40 – $60	$48 – $72	Based on actual retail costs of standard retailers and relevant benchmarks. Includes an allowance for FRC capital costs of $5 per customer per annum. Does not include projected increases in marketing costs (above those incurred for a regulated service) because those are not appropriate for a regulated service.
ORG (2001)	VIC	2002	$50 – $80	$58 – $93	Based on actual retail costs and relevant benchmarks. Includes an allowance for FRC costs of $5 – $10 per customer per annum, which was consistent with cost forecasts provided by retailers. Includes only minor allowances for basic marketing, and no allowance for customer acquisition costs (since these are not necessary for customers on regulated tariffs). ORG noted that the potential for larger NSW retailers to access economies of scale may justify a greater allowance for retail costs in Victoria than in NSW.
IPART (2002)	NSW	Aug 2002 *to* Jun 2004	$45 – $75	$54 – $90	Based on actual retail costs of standard retailers and relevant benchmarks. This included an allowance for FRC costs, but the amount of FRC costs was not separately identified. This included depreciation costs, but did not include allowances for marketing and promotion.
SAIIR (2002)	SA	2003	$80	$90	Based on AGL's actual costs in South Australia and relevant benchmarks. Includes a $10 per customer allowance for the costs of FRC. SAIIR noted that AGL SA is larger than any Victorian retailer and larger in aggregate than any other electricity company. SAIIR suggested that AGL SA's costs should therefore be lower.
CRA – Victoria (2002)	VIC	2003	$90	$101	CRA's cost allowance was based on Victorian retailers' reports of their retail costs for standing offer customers, as reported to ORG during its 2001 investigation of retail pricing.
ICRC (2003)	ACT	Jul 2003 *to* Jun 2006	$85	$95	Based on ActewAGL's actual costs and relevant benchmarks. Includes an allowance for the costs of FRC. ActewAGL claimed FRC costs of $8.33 per customer, but the ICRC did not separately identify the amount for FRC costs. The ICRC considered that diseconomies of scale justified an increased allowance for retail costs relative to Victoria and South Australia.

8BAllowance for retail operating costs

Decision	*State*	*Regulatory period*	*Retail cost per customer (nominal $)*	*Retail cost per customer (2007/08 $)*	*Comments*
OTTER (2003)	TAS	Jan 2004 *to* Dec 2006	$77	$86	Based on Aurora's actual costs and relevant benchmarks. Aurora reported actual costs of $77 per customer (in June 2002 dollars). Does not include an allowance for the costs of FRC (as FRC had not been introduced in Tasmania). OTTER considered that only a small proportion of marketing expenses should be allowed, as the returns to these lie in the potential for increased sales. OTTER recognised the importance of economies of scale, but considered that Aurora should be able to achieve comparable costs to a retailer in SA or the ACT, and so adopted the amount from the ICRC's 2003 decision, less FRC costs of $8.33 per customer.
ESCOSA (2003)	SA	2004	$82	$90	ESCOSA considered that its analysis from 2002 remained relevant, but increased the $80 allowance to reflect inflation.
CRA (2003)	VIC	Jan 2004 *to* Dec 2007	$92	$101	CRA considered that its analysis from 2002 remained relevant, but adjusted this by CPI-1 (to allow for some productivity gain).
ESC (2004)	VIC		$85	$94	In assessing net margins in its review of the effectiveness of retail competition in gas and electricity, ESC assumed that retail operating costs were $85 per customer. This was based on work that the ESC had done for its investigation of retail tariff amendments in December 2003.
IPART (2004)	NSW	Jul 2004 *to* Jun 2007	$70	$76	IPART based its allowance on actual retail operating costs provided by retailers. IPART noted that these estimates were lower than retail operating costs allowed for in other jurisdictions, but considered that the use of higher benchmark costs is inconsistent with determining efficient costs. Includes FRC costs, but there was no specific allowance made for FRC costs. IPART's consultants – NERA – noted that FRC costs continue to be reflected in operating costs such as IT or billing costs. Also includes depreciation costs. Retailers argued that retail costs per customer would increase with FRC as customers churned to other retailers. IPART did not allow for an increase in retail costs to reflect this.

Decision	*State*	*Regulatory period*	*Retail cost per customer (nominal $)*	*Retail cost per customer (2007/08 $)*	*Comments*
ESCOSA (2005)	NSW	Jan 2005 *to* Dec 2007	$84	$90	Based on AGL's actual costs in South Australia and relevant benchmarks. ESCOSA undertook a review of AGL SA's retail costs and concluded that as the results of the cost audit were sufficiently similar to its previous benchmarking exercises there was no justification for replacing the benchmarked results. Includes costs associated with FRC, but excludes depreciation costs (which were considered as part of the retail margin). ESCOSA increased the $82 allowance from its 2003 decision to reflect inflation. ESCOSA allowed a CPI+2% increase in the allowance for retail operating costs over the determination period, to accommodate increased costs per customer as more customers switched to market contracts.
IPART (2007)	NSW	Jul 2007 *to* Jun 2010	$75	$76	Based on actual retail costs of standard retailers and relevant benchmarks. NSW standard retailers' actual retail costs over the period 2002/03 to 2005/06 were in the range of $64 to $84 per customer (adjusted to July 2007 dollars). Does not include an explicit amount for FRC costs, but these continue to be reflected in operating costs. Does not include depreciation costs. IPART allowed a separate amount for recovery of customer acquisition costs ($33 per customer).
QCA (2007)	QLD	Jul 2007 *to* June 2008	$78 **	$78	Based on relevant benchmarks. This included $10 per customer for FRC costs. The QCA also separately allowed $2 per customer for customer acquisition costs. Retail costs were assumed to increase by 3.9% between 2006/07 and 2007/08, reflecting increases in the wage index and the CPI, weighted according to a split of 60 per cent labour costs and 40 per cent other costs. No improvements in productivity.
ICRC (2007)	ACT	Jul 2007 *to* Jun 2008	$95	$95	Based on relevant benchmarks. The ICRC adopted an allowance equivalent to the inflation-adjusted allowance from its 2003 decision. Noting that its allowance is greater than the allowance set out in the draft determinations from IPART and the QCA, the ICRC commented that the recovery of similar fixed costs across a larger customer base could account for some of the difference.

8BAllowance for retail operating costs

Decision	*State*	*Regulatory period*	*Retail cost per customer (nominal $)*	*Retail cost per customer (2007/08 $)*	*Comments*
ESCOSA (2007)	SA	Jan 2008 *to* Dec 2010	$97	$96	Allowance based on previous regulatory allowance of $84, escalated at CPI+2% to 2008 dollars. ESCOSA noted that analysis of AGL SA's actual operating costs attributable to the standing contract retail business reveals that the allowance of $97 is sufficient to cover all AGL SA's retail operating costs and the majority of customer acquisition costs. ESCOSA noted that AGL SA and other retailers are undertaking significant capital expenditure to improve retail operations, and that this will lower retail costs. ESCOSA considers that an efficient retailer would pass on some of these cost savings. Based on information provided by AGL SA, ESCOSA concluded that the allowance for retail operating costs should vary by CPI-4.1% over the regulatory period.
OTTER (2007)	TAS	Jan 2008 *to* Jun 2010	$85	$87	Based on Aurora's actual costs and relevant benchmarks. Aurora advised OTTER that its actual cost to serve in 2005/06 was $94 per customer (adjusted to July 2007 dollars), including depreciation. OTTER's allowance for retail costs excludes depreciation costs. OTTER considers that FRC costs are implicitly included, as they are in other jurisdictions. OTTER noted that costs of marketing and customer acquisition are not typically included in allowances for non-contestable customers.
CRAI (2007)	VIC		$75	$76	Based on relevant benchmarks, CRAI estimated that retail operating cost for electricity businesses in Victoria are $75 per customer. This excluded any allowance for customer acquisition costs.

Table 11: Electricity retail operating costs in other regulatory decisions

Source: See Appendix 3 for a list of sources for these decisions.

* IPART allowed $75 per customer for retail operating costs and $35 per customer for customer acquisition costs, but considered that there may be some double-counting and so reduced the total amount to $105 per customer. Since customer acquisition costs are not appropriate for non-contestable customers in Western Australia, double-counting is not an issue.

** Excludes $2 per customer for customer acquisition costs.

8BAllowance for retail operating costs

In order that the benchmark values for retail operating costs set out in Table 11 provide guidance as to efficient retail operating costs for non-contestable customers in Western Australia, it is important to consider whether depreciation, customer acquisition costs and FRC-related costs have been included.

Depreciation

Depreciation costs can be included as a line item in retail costs, or as a component of the retail margin. For the purposes of this report, depreciation is be treated as a component of the retail margin.

The treatment of depreciation is important for the benchmarking exercise. Where depreciation is treated differently, the retail operating costs in Table 11 should not be directly compared.

For some of the determinations considered in Table 11, the treatment of depreciation is clear:

- IPART's earlier determinations explicitly include depreciation in retail operating costs;
- the most recent determinations by IPART and OTTER exclude depreciation from retail operating costs; and
- ESCOSA's determinations exclude depreciation from retail operating costs.

For other determinations the treatment of depreciation is unclear. Due to this uncertainty, the allowances for retail operating costs set out in Table 11 are not be adjusted to account for differences in the treatment of depreciation. However, it is important to recognise that those regulatory determinations that include depreciation as a line item in retail operating costs – including IPART's early determinations and likely including other determinations – overstate the retail operating costs that are relevant for this review.

An indication of the magnitude of this overstatement is provided in work undertaken for IPART's most recent retail pricing determination. In advising IPART, Frontier Economics noted that the average cost of depreciation reported and forecast by the standard retailers in NSW over the period 2002/03 to 2009/10 is between $8 per customer and $9 per customer.[27]

Customer acquisition costs

Customer acquisition costs are incurred by retailers in competitive markets, with new entrants endeavouring to attract customers away from incumbents, and incumbents endeavouring both to retain existing customers and to attract new customers. Customer acquisition costs are primarily marketing costs (typically direct marketing costs), but also include the costs of transferring customers between retailers.

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[27] Frontier Economics and SFG Consulting, *Mass market new entrant retail costs and retail margin, Public Report prepared for the Independent Pricing and Regulatory Tribunal*, March 2007.

In the past, customer acquisition costs have not been explicitly included in regulatory allowances for retail operating costs (although some allowance has typically been made for general marketing costs). This has changed more recently, with IPART including an allowance for customer acquisition costs in its most recent determination, and the QCA and ESCOSA since following suite in allowing for customer acquisition costs.

Importantly, retailers face customer acquisition costs only in competitive markets. Where markets have not been opened to competition, retailers do not face the same costs of marketing to customers or transferring customers. Clearly then, customer acquisition costs are not relevant to the retail operating costs for non-contestable customers in Western Australia.

In Table 11 the specific allowances for customer acquisition costs have been excluded from the retail operating cost allowances in IPART's 2007 determination and the QCA's 2007 determination. For ESCOSA's 2007 determination, in which customer acquisition costs were allowed, but the magnitude of these costs was not specified, no adjustment has been made. As a result, the retail operating cost allowance from ESCOSA's 2007 determination overstates the costs that are appropriate to Western Australia.

FRC-related costs

FRC-related costs are the additional capital and operating expenses that retailers face as a result of the introduction of FRC. Costs to retailers associated with FRC include project management costs, capital costs associated with updating retail systems and enabling retail interfaces, and additional operating costs.

While FRC has not yet been introduced in Western Australia, retailers in Western Australia are nevertheless preparing their retailing systems for the introduction of FRC. While FRC-ready retailing systems may not be necessary at this stage, there are likely to be benefits to making these investments at this stage – in particular, while broader investments are being made to retailing systems to improve efficiency, it is likely less costly to also ensure that the retailing systems are FRC-ready.

Certainly there are some FRC-related retailing costs that incumbent retailers in Western Australia will not face at this time – in particular, the costs of transferring customers. The result is that allowances for FRC-related costs in other jurisdictions will be in excess of the costs that incumbent retailers in Western Australia would face.

However, since regulatory benchmarks do not separately identify the capital costs of FRC-ready retailing systems from the operating costs of transferring customers, we do not attempt to adjust retail operating costs in other jurisdictions to remove allowances for FRC costs. The result is that regulatory benchmarks from jurisdictions in which FRC-related costs are included are likely to overstate the retail operating costs of an efficient retailer in Western Australia to some extent. With allowances for FRC-related costs tending to be in the range of $5 to $10 per customer per annum (including both the capital costs of

preparing for FRC and the costs of transferring customers), the extent of this overstatement will not be too substantial.

8.3.4 Relevance of benchmarks to Western Australia

An important part of benchmarking retail operating costs is considering the relevance to Western Australia of cost estimates from other jurisdictions. Section 8.3.2 addressed the question of the extent to which incumbent retailers in Western Australia face the same categories of retail operating costs as do retailers in other jurisdictions. This still leaves the question of the extent to which retail activities in other jurisdictions, and the costs of these activities, are similar to Western Australia.

Broadly speaking, retailing activities are similar across different jurisdictions. This accounts for the wide use of the benchmarking approach for determining an appropriate allowance for retail operating costs. Nevertheless, there can be differences between retailers in terms of the customers to whom they supply energy and the scale and scope of their activities. These differences may lead to differences in costs. There may also be differences in retail operating costs across jurisdictions if the costs of inputs into retailing vary across jurisdictions.

Scale of retailers

Regulatory decisions in other jurisdictions suggest that there are some economies of scale available in electricity retailing. With some retail operating costs being fixed,[28] the average retail operating cost per customer is likely to fall as customer numbers increase.

Economies of scale available to retailers in other jurisdictions will be reflected in the retail operating costs allowed in pricing determinations in these jurisdictions. In benchmarking retail operating costs, therefore, consideration must be given to the scale of retailers in each jurisdiction. The available evidence suggests that an efficient incumbent in Western Australia, retailing to non-contestable customers, would be able to achieve the same economies of scale as incumbent retailers in other jurisdictions.

First, it is clear that the retail market in Western Australia is sufficiently large that an incumbent retailer can operate at a comparable scale to retailers in other jurisdictions. Synergy currently supplies approximately 800,000 residential customers along with a number of other small retail customers. This is comparable to the number of small retail customers supplied by the standard retailers in New South Wales (between 750,000 and 1,500,000 in 2005/06) and the number of customers supplied by the incumbent retailers in Queensland (PowerDirect had approximately 430,000 customers at the time of its sale to AGL, and Sun Retail had approximately 830,000 customers at the time of its sale

[28] For example, in work undertaken for IPART's most recent retail electricity pricing determination, Frontier Economics estimated that 75 per cent of retail operating costs are fixed costs. This was based on cost data provided by the standard retailers in NSW. Frontier Economics and SFG Consulting, *Mass market new entrant retail costs and retail margin, Public Report prepared for the Independent Pricing and Regulatory Tribunal*, March 2007, pages 8-9

to Origin Energy). In other jurisdictions, the number of customers supplied by retailers is significantly less: AGL SA supplies approximately 320,000 small retail customers on regulated tariffs in South Australia, Aurora Energy supplies approximately 260,000 small retail customers in Tasmania and ActewAGL supplies approximately 150,000 small retail customers in the ACT.[29]

Second, the evidence suggests that the average cost curve for retailing activities is quite flat over a wide range of customer numbers. For instance, evidence from NSW indicates that, despite differences in the scale of standard retailers, their actual retail operating costs per customers were similar.[30] That the average cost curve is flat over a wide range of customer numbers is also supported by the entry and survival of smaller retailers operating, apparently profitably, for some time. In the NEM, for instance, several new entrant retailers are operating successfully at a scale below the incumbent retailers: Jack Green recently reached 40,000 customers, and is targeting 100,000 customers;[31] Australian Power & Gas recently reached 75,000 customers;[32] and Victoria Electricity has reached 250,000 customers.[33]

Scope of retailers

As well as economies of scale, there may be some economies of scope available to retailers in other jurisdictions. Economies of scope may be particularly relevant where retailers are able to provide their customers with dual-fuel offerings and thereby reduce the variable costs of retailing.

However, the available evidence suggests that regulatory benchmarks from other jurisdictions do not reflect economies of scope. This is because regulators have tended to base their cost estimates on stand-alone electricity retailers. For instance, in Queensland, the *Electricity Industry Act 1994* (as amended by the *Electricity and Other Legislation Amendment Act 2006*) requires that the allowance for retail costs is based on an efficient retail business that "is carried on separately from any other business". In its report for the QCA, CRA International note that

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[29] Retailers in the NEM increasingly supply customers in several jurisdictions, enabling them to increase their customer base beyond that achievable in any single jurisdiction. In particular, both AGL and Origin Energy have substantial customer numbers: AGL supplies approximately 2 million electricity customers and 2 million gas customers across the NEM, and Origin Energy supplies approximately 3 million electricity and gas customers across the NEM. This may enable these large retailers to achieve greater economies of scale in retailing than other retailers. However, there is little to suggest that any economies of scale achieved by retailers of the size of AGL and Origin have been reflected in regulatory decisions.

[30] See, for example: IPART, *Regulated Retail Prices for Electricity to 2004*, Final Report, December 2000; IPART, *Mid-term Review of Regulated Retail Prices for Electricity to 2004*, June 2002; Frontier Economics and SFG Consulting, *Mass market new entrant retail costs and retail margin, Public Report prepared for the Independent Pricing and Regulatory Tribunal*, March 2007, pages 8-9.

[31] See Jack Green web site:
http://investor.jackgreen.com.au/IRM/Company/ShowPage.aspx?CPID=1192&PageName=Jackgreen Raises Funds and Reveals Growth Targets

[32] See Australian Power & Gas media release, 29 January 2008. Available from ASX web site:
http://clients.weblink.com.au/clients/mvl/article.asp?asx=APK&view=2490688

[33] See Victoria Electricity web site: http://www.victoriaelectricity.com.au/?Home/News

this is likely to result in a cost allowance that is in excess of the actual retail costs of the incumbent retailers in Queensland, which have retailing interests outside Queensland and are dual fuel retailers in Queensland.[34] In New South Wales, the Terms of Reference for IPART's most recent price determination required consideration of the costs of a mass market new entrant. IPART interpreted its Terms of Reference as requiring an estimate of the costs of a stand-alone new entrant that has achieved economies of scale; that is, a stand-alone electricity retailer rather than a dual fuel retailer.[35]

Synergy is also unlikely to benefit from economies of scope because it is subject to the gas market moratorium, which prevents it from supplying gas to customers that use less than 0.18 TJ/a of gas until the introduction of FRC in electricity.

In any case, economies of scope in retailing are unlikely to be substantial. Frontier Economics, in advising IPART on its most recent retail price determination, noted that a dual fuel retailer might enjoy some economies that are not available to a stand-alone electricity retailer, but concluded that the available evidence indicated that these economies would be unlikely to have a material effect on costs.[36]

Costs in Western Australia

In submissions to the OOE's Issues Paper, some stakeholders raised the cost of labour in Western Australia as an issue that would affect retail operating costs in Western Australia. Certainly, labour costs are an important element of retail operating costs. In recent work on behalf of the QCA, CRA International estimate that labour costs account for up to 60 per cent of retail operating costs.[37]

In terms of the appropriateness of benchmarks from other jurisdictions, the relevant question is whether labour costs in Western Australia are comparable to labour costs in other jurisdictions. One indication of whether this is the case is provided by considering whether labour costs in Western Australia have recently increased relative to labour costs in other states to such an extent that there is reason to expect that retail operating costs would be higher in Western Australia than in other states. Certainly the focus of comments in response to the OOE's Issues Paper tended to focus on recent increases in labour costs in Western Australia.

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[34] CRA International, *Calculation of the Benchmark Retail Cost Index for 2006-07 and 2007-08*, Final Report, May 2007, page 42.

[35] IPART, *Promoting retail competition and investment in the NSW electricity industry, Regulated electricity retail tariffs and charges for small customers 2007 to 2010*, Electricity – Final Report and Final Determination, June 2007, page 94.

[36] Frontier Economics and SFG Consulting, *Mass market new entrant retail costs and retail margin, Public Report prepared for the Independent Pricing and Regulatory Tribunal*, March 2007, pages 8-9.

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

The labour price index reported by the ABS provides a comparison of relative movements in labour costs in different states. Considering the period over which the regulatory benchmarks in Table 11 are drawn suggests that labour costs in Western Australia have not increased substantially more than labour costs in other states.

The labour price index for total hourly rates of pay excluding bonuses increased by 30.5 per cent in Western Australia from June 2000 to June 2007.[38] Over the same period, the index in other states increased by between 27.9 per cent and 30.1 per cent. This suggests that retail operating costs may have increased at a slightly faster rate over the period from 2000 to 2007 in Western Australia compared to other states, but a difference of only one or two per cent in the rate of increase in labour prices over this period is not sufficiently large to suggest that benchmarks from other jurisdictions are inappropriate to Western Australia.

8.3.5 Conclusion on retail operating costs for non-contestable customers

Retail operating costs for 2007/08

Based on the benchmark decisions on retail operating costs set out in Table 11, we estimate that an efficient retailer in Western Australia would incur retail operating costs of $75 per customer per annum (in 2007/08 dollars) for non-contestable customers. This estimate is considered the most reasonable estimate for the following reasons.

First, we consider that $75 per customer per annum is a reasonable reflection of the most recent retail operating cost benchmarks from other regulatory decisions. As seen in Figure 2, the range across the benchmarks from 2007 is from $76 per customer to $96 per customer (including FRC costs), with an average of $85 per customer. However, the benchmarks from the lower end of this range – from IPART, the QCA and the AEMC – are the more relevant benchmarks:

- ESCOSA's estimate of $95 per customer includes an amount for customer acquisition costs, which are not relevant in Western Australia.
- The estimates from the ICRC and OTTER reflect, in part, the smaller scale of retailers in these jurisdictions, with both regulators having explicitly recognised economies of scale as accounting for the higher costs in these jurisdictions. As discussed, an efficient retailer in Western Australia need not operate at this smaller scale.

As seen in Figure 2, the estimate for retailer operating costs for an efficient retailer in Western Australia (shown by the horizontal red line) is slightly below the lower end of the range across these most recent benchmarks, reflecting the fact that retailers in these other jurisdictions face greater FRC costs.

Second, $75 per customer per annum is within the range across all the benchmarks set out in Table 11. The range across all the benchmarks is from $65

[38] ABS, *Labour Price Index*, 6345.0, September Quarter 2007.

per customer to $101 per customer, with an average of $86 per customer. While $75 per customer is significantly below the highest benchmarked costs, these higher benchmarks are of less relevance to Western Australia:

- CRA acknowledges that its benchmarks for Victoria were adopted in the absence of other better information, and CRA has since revised downwards its benchmark for Victoria.
- Both the ICRC and OTTER acknowledge that their allowances for retail operating costs are higher than in other jurisdictions as a result of the relatively small scale of retailers in these jurisdictions.

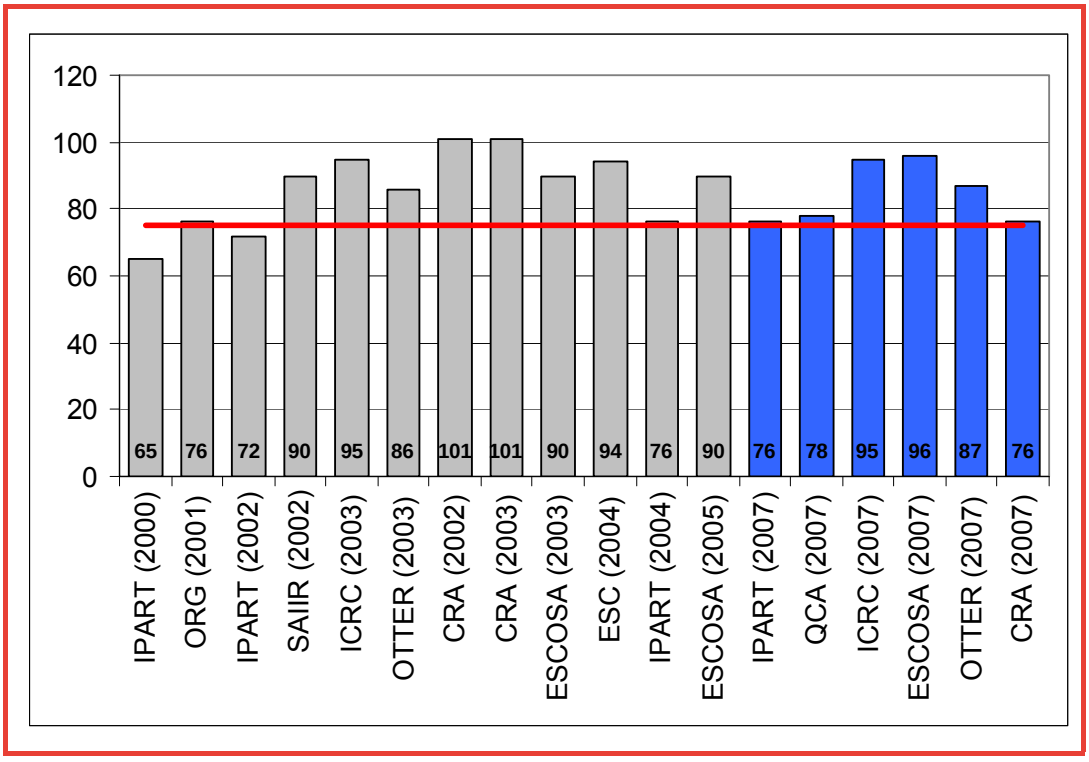

Figure 2: Retail operating cost benchmarks ($/customer, 2007/08)

Third, estimates of efficient retail operating costs for Western Australia that have been provided by Synergy are consistent with the view that $75 per customer is an appropriate estimate of retail operating costs.

Fourth, market evidence suggests that large efficient retailers are able to achieve operating costs lower than $75 per customer. For instance, in presenting their interim results for 2007/08, Origin Energy reported that operating costs per customer (across their entire electricity and gas business) have fallen from $61 per customer to $53 per customer.[39] Similarly, AGL is currently undertaking a

[39] Origin Energy Investor Presentation, *Interim Results Announcement*, 28 February 2008.

project to restructure its retailing activities, including to increase process automation across sales and customer contact, billing, collection and market processes. AGL has forecast that the efficiencies resulting from this project will reduce retail operating costs from $91 per customer to $68 per customer, and that further savings would be available from additional scale.[40] AGL has recently confirmed that it has achieved all 2006/07 cost targets for the project.[41] In presenting their interim results for 2007/08, AGL reported that operating costs per customer (across their entire electricity and gas business) have fallen from around $71 per customer to around $66 per customer. [42]

Furthermore, in their report for the AEMC, CRA International note that AGL's stated retail operating costs were $85.60 per customer for 2005/06 and $84.50 per customer for 2006/07, including customer acquisition costs. This leads CRA International to conclude that their estimate of $75 per customer excluding customer acquisition costs may be over-stated.[43]

Retail operating costs over the regulatory period

Having formed the view that $75 per customer per annum is an appropriate allowance for retail operating costs for non-contestable regulated tariffs, it is also necessary to consider how retail operating costs are likely to change over the regulatory period.

The starting point for considering how retail operating costs are likely to change over the regulatory period is to consider how the costs of inputs into retail activities are likely to change. The major input into retail activities is labour: CRA International have estimated that 60 per cent of the cost of retail activities is accounted for by labour costs.[44] As labour costs change, therefore, retail operating costs will also change.

Despite the large labour component of retail operating costs, there is reason to favour adjusting retail operating costs by a general price index. First, this will provide for consistency with the other cost elements of retail tariffs and enable a far simpler annual adjustment mechanism. Second, retail operating costs also consist of non-labour costs which are likely to increase in line with a general price index. Finally, a labour price index and a general price index are likely to move together over time, so that the choice between the two will not have a material impact on tariffs.

In considering how retail operating costs are likely to change over the regulatory period, it is also important to consider whether a retailer would be expected to achieve efficiency gains over the regulatory period. A retailer may become more

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[40] AGL Investor Presentation, *AGL/Origin merger update, Powerdirect acquisition and 2007 interim results*, 19 February 2007.

[41] AGL Investor Presentation, *Moving Forward*, 17 December 2007.

[42] AGL Investor Presentation, *2008 Interim Results*, 29 February 2008.

[43] CRA International, *Impact of Prices and Profit Margins on Energy Retail Competition in Victoria*, November 2007.

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

efficient if there are expected to be changes in the technology of production over the regulatory period that would allow a reduction in costs. However, it is difficult to foresee what efficiency improvements would be available over the regulatory period that would enable a reduction in costs from the existing efficient benchmark of $75 per customer per annum.

A retailer may become less efficient if it loses scale, so that its cost per customer increases. However, as discussed above, the evidence suggests that the average cost curve for retailing activities is quite flat over a wide range of customer numbers, so that an efficient retailer is unlikely to face diseconomies of scale.

For these reasons, we consider that retail operating costs should not be adjusted over the regulatory period to reflect any changes in efficiency, but should remain constant in real terms. This is the approach most commonly used in other jurisdictions.

8.3.6 Retail operating costs of new entrants

While the focus in this section has been on the retail operating costs that an efficient incumbent would face in retailing to non-contestable customers, it is also important to consider whether a new mass market retailer would be able to achieve similar costs. In the event that FRC is introduced, new entrants will find it difficult to compete for customers if the regulated tariff is based on an allowance for retail operating costs that they cannot achieve.

The principal issue in regard to the retail operating costs of new entrant retailers is whether they would have the scale to achieve retail operating costs that are comparable to those of the incumbent. The available evidence suggests that they would be able to do so.

New entrant retailers have been able to enter the retail markets in other jurisdictions without investing in systems that are as complex as the incumbent retailer's legacy systems. One strategy that smaller retailers have successfully adopted is to out-source key retailing functions and, in this way, avoid some of the fixed costs that incumbent retailers have traditionally incurred in developing customer information systems and billing and revenue systems. For instance, Australian Power & Gas reports that it out-sources to third-party service providers the following functions: sales, customer transfer and billing, and service and payment functions.[45] Australia Power & Gas pays for these outsourced services on a per customer basis, meaning that these costs are variable rather than fixed.

That smaller new entrants are able to achieve cost levels comparable to incumbent retailers is indicated by the ability of smaller retailers to successfully compete with incumbents. As discussed in Section 8.3.4, several smaller new entrants retailers have been successfully operating in the NEM at a much smaller scale than the incumbent retailers: Jack Green recently reached 40,000 customers,

[45] Australian Power & Gas Investor Presentation, 5 December 2007. Available from Australian Power & Gas web site: http://www.australianpowerandgas.com.au/index.cfm?s=5C8592F0-157E-DAE8-81305CC2A2D1CF85&m=E9442EC1-C2D1-AB8B-CECB10D32F6F4000

and is targeting 100,000 customers; Australian Power & Gas recently reached 75,000 customers; and Victoria Electricity has reached 250,000 customers.

This suggests that an allowance for retail operating costs that is based on the costs that an efficient incumbent would incur is likely to also be relevant for new entrant retailers in the event that FRC is introduced in Western Australia.

8.4 RETAIL OPERATING COSTS FOR CONTESTABLE CUSTOMERS

For the purposes of this review, Frontier Economics is estimating retail operating costs for all classes of customers, not just residential and small business customers.

Determining an appropriate allowance for retail operating costs for contestable customers in Western Australia – which is appropriate for the new L3, M1, R3, S1 and T1 tariffs – is more difficult than determining an appropriate allowance for retail operating costs for non-contestable customers. The reason is simply that there is much more publicly available information available on retail operating costs for the mass market than there is for retail operating costs of medium and large businesses. The regulatory benchmarks from other jurisdictions do not provide useful information because these deal only with the cost to serve the mass market. There is also a lack of market information on retail operating costs for medium and large businesses.

The issue of the extent to which retail operating costs vary for customers in different tariff classes was raised in the OOE's Issues Paper. In response, Alinta commented that, generally, there are only minor differences in retail operating costs between customers in different tariff classes. Alinta also commented that the retail operating cost to residential customers is higher as a result of more frequent customers service activity. Perth Energy commented that variable retail operating costs will vary only slightly with tariff class, but most retail operating costs are fixed costs in any case. Other stakeholders did not respond on this issue.

However, we consider that retail operating costs for medium and large business customers will be significantly higher than retail operating costs for small residential and business customers. This will reflect such things as more substantial marketing costs for larger contestable customers, account management costs and the additional costs of pricing the loads of large customers.

This is supported by information provided by Synergy during the course of consultation for this review. Synergy has provided a breakdown of their actual retail operating costs, allocated to different classes of customers (although not to different tariffs). The information provided by Synergy is confidential.

Synergy has also provided assumptions as to the new entrant retail operating costs for customers on particular tariffs adopted for the purposes of their tariff modelling. Again this information is confidential.

We consider that the following assumptions in regard to retail operating costs for contestable customers are appropriate:

- For the new L3, M1 and R3 tariffs, retail operating costs are estimated to be $700 per customer.
- For the S1 and T1 tariffs, retail operating costs are estimated to be $2,000 per customer.

These costs are broadly consistent with the information provided by Synergy.

8BAllowance for retail operating costs

9 Allowance for retail margin

The retail margin represents the return that a retailer earns. The retail margin is required to compensate the retail business (and ultimately the investors in the business) for the risks that the business faces. The greater the risk, the greater the retail margin that is required in order that capital invested earns an appropriate return.

This section estimates the retail margin that an electricity retailer in Western Australia would require. Consistent with the focus on cost reflective tariffs, the retail margin is assessed on the basis of the return that an efficient retailer in Western Australia would require, given the risks that it faces.

9.1 DEFINING RETAIL MARGIN

There are several different ways of defining the retail margin.

The most important distinction is between the gross retail margin and the net retail margin:

- The **gross retail margin** is defined as the retailer's revenues minus energy purchase costs and network costs. The gross retail margin incorporates retail operating costs.
- The **net retail margin** is defined as the retailer's revenues minus energy purchase costs, network costs and retail operating costs. The net retail margin excludes retail operating costs.

Regulators in most jurisdictions in Australia define the net retail margin for the purposes of pricing determinations, and treat retail operating costs as a separate component of costs. This is the approach that is adopted for the purposes of this review.

There are also different ways of understanding the net retail margin:

- Net retail margin can be defined as the margin over total costs (including energy purchase costs, network costs and retail operating costs) or the margin over controllable costs (including energy purchase costs and retail operating costs, but excluding network costs). Most regulators in other jurisdictions take the former approach. ESCOSA, however, adopts the latter approach, but typically also reports a margin over total costs for the purposes of benchmarking.

  For the purposes of this review, we define the retail margin as the margin over total costs.

- Net retail margin can be defined as the EBIT margin (earnings before interest and taxation) or the EBITDA margin (earnings before interest, taxation, depreciation and amortisation). The EBITDA margin will be higher than the EBIT margin because it incorporates an allowance for depreciation. Regulators in other jurisdictions vary as to whether they define an EBIT margin or an EBITDA margin, reflecting variations in whether depreciation

is included as a line item in retail operating costs (as discussed in Section 8.3.3).

For the purposes of this review, we define the retail margin as the EBITDA margin. This is consistent with the approach to retail operating costs we have adopted, with depreciation not included within the estimate for retail operating costs.

9.2 RETAIL MARGIN FOR DIFFERENT CUSTOMERS

The Terms of Reference for this review and assessment of retail tariffs requires consideration of all regulated tariffs. The evidence suggests that the appropriate retail margin will vary across different customer classes. In particular, the retail margin appropriate for non-contestable customers will be lower than the retail margin appropriate for contestable customers, as a result of the different risks that are associated with serving these groups of customers.

For this reason, the retail margin for contestable and non-contestable customers is separately estimated. The retail margin for non-contestable customers is incorporated into those tariffs for which a majority of customers are below the contestability threshold: the A1, B1, K1, new L1 and R1 tariffs. The retail margin for contestable customers is incorporated into those tariffs for which a majority of customers are above the contestability threshold: the new L3, M1, R3, S1 and T1 tariffs. The retail margin (and retail operating costs) for the W1 tariff and streetlight tariffs are discussed separately in Section 10.

9.3 METHODOLOGY FOR DETERMINING THE RETAIL MARGIN

As with retail operating costs, regulators in other jurisdictions have tended to determine the appropriate retail margin using one or both of two approaches: an assessment of the appropriate retail margin based on a bottom-up analysis of the costs that comprise the retailer's margin; and benchmarking against allowances for the retail margin in other regulatory decisions.

The relative weight given to these two approaches is often driven by the availability of data. If useful data on the costs that comprise the retailer's margin is not available, then benchmarking is used as the basis for estimating the retail margin.

During the course of public consultation undertaken during this review, stakeholders were invited to provide information relevant to a bottom-up assessment of the retail margin. No information was provided. As a result, the appropriate retail margin is estimated on the basis of benchmarks from other jurisdictions, and other market evidence, assessed for relevance to Western Australia.

9.4 BENCHMARKING AGAINST REGULATORY ALLOWANCES

Table 12 provides an overview of the assessment of the retail margin in recent regulatory decisions in other jurisdictions in Australia.

Decision	*State*	*Regulatory period*	*Retail margin*	*Comment*
IPART (2000)	NSW	Jan 2001 *to* Jun 2004	1.5 – 2.5 %	Based on benchmarking against other regulatory decisions, a review of publicly available information on electricity retail profit margin and consideration of submissions. IPART noted that the standard retailers in NSW are protected from energy purchase risk by the ETEF.
ORG (2001)	VIC	2002	2.5 – 5.0 %	Based on benchmarking against other regulatory decisions, a review of publicly available information on electricity retail profit margins and information from retailers on their profit margin. ORG considered that the activities of electricity retailers are generally considered to be low risk. ORG recommended a higher margin than adopted by IPART because: NSW retailers are protected from energy purchase risk by ETEF; and NSW retailers are government-owned enterprises with a lower cost of capital.
IPART (2002)	NSW	Aug 2002 *to* Jun 2004	1.5 – 2.5 %	Based on benchmarking against other regulatory decisions and consideration of submissions. IPART considered that the retail margin should reflect the risk associated with energy purchasing costs, customer default and bad debt, and competition from electricity substitutes. IPART considered that higher retail margins in Victoria are not an appropriate benchmark, because standard retailers in NSW are protected from energy purchase risk by the ETEF.
SAIIR (2002)	SA	2003	5 %	Based on benchmarking against other regulatory decisions and consideration of submissions. SAIIR considered that Victoria is a better benchmark than NSW, because standard retailers in NSW are protected from energy purchase risk by the ETEF. SAIIR considered that a retail margin from the upper end of Victoria's benchmark range was not unreasonable, given the risks of operating in the peaky South Australian market.
ICRC (2003)	ACT	Jul 2003 *to* Jun 2006	3 %	Based on benchmarking against other regulatory decisions and consideration of submissions. The ICRC considered that the standard retailer in the ACT did not face the same risks as the standard retailer in South Australia. The ICRC therefore allowed a lower retail margin than SAIIR. The retail margin also did not include an allowance for energy purchase risk, which the ICRC considered were allowed for in the allowance for wholesale costs.
OTTER (2003)	TAS	Jan 2004 *to* Dec 2006	3 %	Based on benchmarking against other regulatory decisions and consideration of submissions. OTTER considered that the standard retailer in Tasmania faced minimal energy purchase risk (due to the operation of a vesting contract) and minimal contestability risk. The retail margin included an allowance for bad debt, working capital and profit.
CRA (2002)	VIC	2003	5 – 8 %	Based on benchmarking against previous decisions in Victoria, and consideration of retail margins that would be earned without a change in tariffs. CRA considered that a retail margin in excess of that provided by the ORG for 2002 would promote more effective competition and enable more customers to benefit from competition.

Decision	*State*	*Regulatory period*	*Retail margin*	*Comment*
CRA (2003)	VIC	Jan 2004 *to* Dec 2007	5 – 8 %	Based on benchmarking against previous decisions in Victoria, and consideration of retail margins that would be earned without a change in tariffs. CRA considered that the retail margin should reflect any energy purchase risk that was not accounted for in estimates of wholesale costs, and that the retail margin should also facilitate the emergence of competition. CRA considered that it was reasonable to increase the retail margin during the regulatory period, to account for increasing uncertainty over forward estimates.
ESCOSA (2003)	SA	2004	5 %	Based on benchmarking against other regulatory decisions and consideration of submissions. ESCOSA considered that the 5 per cent retail margin allowed for in SAIIR's previous report continued to reflect the unique characteristics of the South Australian market, including a single dominant retailer, peaky load, and emerging competition.
IPART (2004)	NSW	Jul 2004 *to* Jun 2007	2 %	Based on benchmarking against other regulatory decisions and consideration of submissions. IPART considered that the retail margin should reflect the risk associated with energy purchasing costs, customer default and bad debt, and competition from electricity substitutes. IPART considered that higher retail margins in Victoria are not an appropriate benchmark, because standard retailers in NSW are protected from energy purchase risk by the ETEF.
ESCOSA (2005)	SA	Jan 2005 *to* Dec 2007	5 %	Based on benchmarking against other regulatory decisions, a bottom-up estimation of EBITDA and consideration of submissions. ESCOSA considered that Victoria was a better benchmark than NSW because standard retailers in NSW were protected from energy purchase risk by the ETEF. ESCOSA used a return on investment methodology to confirm that a 5 per cent margin was reasonable. The methodology included a return on capital, depreciation, amortisation, taxes and profit.
IPART (2007)	NSW	Jul 2007 *to* Jun 2010	5 %	Based on benchmarking against other regulatory decisions, a review of publicly available information on electricity retail profit margin, a bottom-up estimation of EBITDA, and an estimation of the cashflows required by standard retailers given the risks they face. Part of the explanation for the increase in the retail margin, relative to the retail margin adopted by IPART in previous decisions, was that the ETEF was rolling off over the regulatory period, increasingly exposing retailers to energy purchase risk. The retail margin was calculated on an EBITDA margin (ie, it included an allowance for depreciation costs). IPART noted that evidence suggests that EBITDA margins are approximately 1 per cent higher than EBIT margins.
QCA (2007)	QLD	Jul 2007 *to* June 2008	5 %	Based on benchmarking against previous decisions in Victoria, and consideration of retail margins that would be earned without a change in tariffs. The QCA noted that retailers face two key types of risk: volume risk and price risk. A retail margin of 5% was considered appropriate given the QCA's inclusion of short-run variations in wholesale costs in its allowance.

9BAllowance for retail margin

Decision	*State*	*Regulatory period*	*Retail margin*	*Comment*
ICRC (2007)	ACT	Jul 2007 *to* Jun 2008	4 %	Based on benchmarking against other regulatory decisions and consideration of submissions. The ICRC consider that an increase on its previous allowance for retail margin of 3% was justified on the basis of increased price volatility in the wholesale energy market.
ESCOSA (2007)	SA	Jan 2008 *to* Dec 2010	5 %	Based on benchmarking against other regulatory decisions, and informed by a bottom-up estimation of EBITDA and consideration of submissions.
OTTER (2007)	TAS	Jan 2008 *to* Jun 2010	3 %	Based on benchmarking against other regulatory decisions and consideration of submissions. The retail margin is determined on an EBITDA basis. OTTER noted that Aurora remains substantially protected from energy purchase risk through the operation of a vesting contract (which continues to cover up to 90% of energy consumer by tariff customers), and is substantially protected from volume risk because FRC has not yet been introduced in Tasmania.

Table 12: Electricity retail margin in other regulatory decisions

Source: See Appendix 3 for a list of sources for these decisions.

9.5 RELEVANCE OF BENCHMARKS TO WESTERN AUSTRALIA

In undertaking a benchmarking exercise, it is important to consider the relevance to Western Australia of the retail margins adopted in other jurisdictions.

The appropriate retail margin depends principally on the extent to which a business is exposed to systematic risk.[46] There are two key types of systematic risk to which electricity retailers are exposed: volume risk and energy purchase risk.

Volume risk is a result of changes in customers' energy use and, in a competitive market, changes in customer numbers. Volume risk has a systematic component as a result of the relationship between customers' energy use and aggregate economic conditions. Volume risk can also arise where hedging activity cannot perfectly match customers' energy use.

Energy purchase risk is a result of the volatility of wholesale electricity prices. Energy purchase risk has a systematic component as a result of the relationship between wholesale electricity prices and aggregate economic conditions.

In Western Australia, Synergy is protected to some extent from both volume risk and energy purchase risk. However, the extent of this protection varies for contestable and non-contestable customers.

9.5.1 Volume risk

In regard to volume risk, FRC has not yet been introduced in Western Australia, so that Synergy is not exposed to the risk that small retail customers will switch to new entrant retailers. Nevertheless, Synergy remains exposed to changes in its customers' energy use and to the risk that contestable customers will switch to new entrant retailers.

This suggests that the appropriate benchmarks for the retail margin for non-contestable customers are those jurisdictions in which FRC has not been introduced. Of the benchmarks set out in Table 12, only Tasmania has not introduced FRC.

On the other hand, the appropriate benchmarks for the retail margin for contestable customers are those jurisdictions in which FRC has been introduced. Of the benchmarks set out in Table 12, all jurisdictions aside from Tasmania have introduced FRC.

The notional wholesale meter

In comments in response to the OOE's Issues Paper, the IMO raised the issue of the volume risk to Synergy associated with the notional wholesale meter. While the notional wholesale meter will increase Synergy's exposure to metering errors, it is not clear that this has a systematic component. In other words, it is not clear

[46] Systematic risk is the result of exposure to overall economics or market conditions.

that the risk to which Synergy is exposed due to the notional wholesale meter would vary with economic conditions.

In any case, the issue of the notional wholesale meter, and its impact on Synergy, is really an issue that may become important with the introduction of FRC. At that point, the existing arrangements would have the potential to expose Synergy to costs and/or risks that differ both from other retailers in Western Australia and other retailers in the Australia (against which the costs and risks that Synergy faces are benchmarked).

9.5.2 Energy purchase risk

In regard to energy purchase risk, two issues require consideration: the impact of the Vesting Contract on the energy purchase risk that Synergy faces and the impact of wholesale market volatility on energy purchase risk.

The Vesting Contract and energy purchase risk

The Vesting Contract between Verve Energy and Synergy reduces Synergy's exposure to wholesale electricity prices for those loads covered by the Vesting Contract.[47]

The Vesting Contract is a bilateral contract between Verve Energy and Synergy for the wholesale supply of both capacity credits and energy. The price under the Vesting Contract is based on a netback calculation under which Synergy pays Verve Energy an amount equal to Synergy's sales revenues less a defined amount for retail operating costs and retail margin, network costs and other specified market and regulatory costs. The result is that Synergy is not exposed to energy purchase risk for the volumes covered by the Vesting Contract: regardless of the wholesale electricity price, Synergy will recover the defined amount for retail operating costs and retail margin.

Despite the Vesting Contract, Synergy remains exposed to some degree of energy purchase risk. The principal reason is that the Vesting Contract does not cover all of Synergy's volumes. The Vesting Contract originally provides contract cover for all tariff customers and for all customers on retail contracts that Synergy inherited from Western Power Corporation. However, the volumes under the Vesting Contract are designed to decline over time. The rate at which volumes under the Vesting Contract decline depend on a number of factors, including:

- the rate at which the contracts that Synergy inherited from Western Power Corporation expire;
- the rate at which tariff customers churn to contracts (either with Synergy or with other retailers);
- the timing of the introduction of FRC; and
- the implementation of the displacement mechanism.

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[47] For an overview of the operation of the vesting arrangements, see: Office of Energy, *Overview of the Vesting Arrangements*, September 2006.

The displacement mechanism requires Synergy to enter into new wholesale supply contracts over a defined timetable to displace capacity and energy provided by Verve Energy under the Vesting Contract.[48]

The extent to which Synergy's loads are covered by the Vesting Contract will vary over the period to 2011/12. In 2008/09, over 90 per cent of tariff loads are forecast to be covered by the Vesting Contract. As of 2011/12 this is forecast to drop close to 70 per cent. It is clear, therefore, that over the entire forecast period the Vesting Contract will protect Synergy from energy purchase risk for the majority of its tariff load.

This suggests that the appropriate benchmarks for the retail margin for non-contestable customers in Western Australia are those jurisdictions in which retailers are protected from energy purchase risk. Of the benchmarks set out in Table 12, this includes Tasmania, NSW (prior to the 2007 Determination) and the ACT in 2003.

Wholesale market volatility and energy purchase risk

In considering the benchmarks from other jurisdictions, it is also necessary to consider whether the extent to which retailers face price risk due to the operation of the wholesale market is comparable. In particular, given that the benchmarks from other jurisdictions are for retailers that are active in the NEM, there is a question as to whether retailers in the NEM might face different energy purchase risk to retailers in the WEM. Given that the NEM has a much higher price cap than the WEM, it might be considered that the retailers in Western Australia are exposed to less energy purchase risk.

However, the evidence suggests that any difference between spot prices in the WEM and the NEM is unlikely to have a material impact on the appropriate retail margin. The most detailed treatment of risk for the purposes of determining an appropriate retail margin for an electricity retailer of which we are aware is the work by Frontier Economics and SFG Consulting for IPART's most recent pricing determination. In determining the appropriate retail margin, Frontier Economics and SFG Consulting adopted an expected returns approach that explicitly accounted for the systematic component of both energy purchase risk and volume risk. Energy purchase risk was incorporated by considering the

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[48] Under the Vesting Contract, Synergy has scope to delay displacement:

- Synergy can elect to bring forward or delay defined amounts of displacement by a year, subject to making its roll-over request by the specified deadline.
- Synergy can elect to request a deferral of displacement under certain circumstances. Synergy can apply for deferral if the costs of generation offered under the displacement tender are greater than the costs of generation under the Vesting Contract. Synergy is able to continue to seek deferrals of tendered displacement obligations, but these requests must be made at least 3 years in advance of the scheduled date of displacement and must be supported by evidence.

Synergy's ability to request a deferral of displacement where the price of tendered generation is greater than the average price under the Vesting Contract provides Synergy with some scope to manage its exposure to risk as the Vesting Contract rolls-off.

risk to a mass market retailer associated with a hedging position that reflected a very conservative approach to risk. The 5 per cent retail margin recommended by Frontier Economics and SFG Consulting reflected this conservative hedging position. The report by Frontier Economics and SFG Consulting concluded that:

> … the high degree of hedging that electricity retailers are likely to engage in, and the relatively weak relationship between prices and aggregate economic conditions, means that [energy purchase] risk has a small impact on retail margins …

This suggests that any difference in the variability of spot prices as between the WEM and the NEM is unlikely to have a material impact on the appropriate retail margin.

9.6 OTHER MARKET EVIDENCE

In addition to the benchmark retail margins discussed in 9.4, there is also market evidence available that can be used to inform the appropriate retail margin.

Evidence on the retail margin appropriate to a mass-market retailer in NSW has been reported for the purposes of IPART's 2007 determination. Bottom-up estimates of the appropriate retail margin were calculated and reported by three consultants:[49]

- KPMG calculated that the retail margin appropriate to a mass market retailer in NSW was between 2.5 per cent and 4.6 per cent.
- NERA calculated that the retail margin appropriate to Integral Energy was between 2.8 per cent and 5.4 per cent, but later revised this to 4.7 per cent to 8.6 per cent based on a revised estimate of asset values.
- Frontier Economics and SFG Consulting calculated that the retail margin appropriate to the standard retailers was between 4.3 per cent and 5.0 per cent.

Having considered this evidence, and other evidence, IPART concluded that the appropriate retail margin was 5 per cent. This evidence is consistent with a retail margin of 5 per cent for a retailer that is exposed to energy purchase risk and volume risk.

Retail margins have also been reported for a range of other retailers. For instance, over a number of years, AGL has reported EBIT margins of between 4.4 per cent and 7.7 per cent and Origin has reported EBIT margins of between 1.9 and 7.0 per cent. The difficulty with benchmarking against this market evidence is ensuring like-for-like comparisons. For instance, EBIT margins that exclude customer acquisition costs (because these are treated as part of retail operating costs) are likely to be significantly less than margins observed in the market. There are also likely to be other differences between the breakdown of operating costs in regulatory decisions and in financial accounts. One way of comparing

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[49] See: Frontier Economics and SFG Consulting, *Mass market new entrant retail costs and retail margin, Public Report prepared for the Independent Pricing and Regulatory Tribunal*, March 2007, pages 42-47.

margins on a like-for-like basis is to compare gross margins (which include retail operating costs). In their report for IPART, Frontier Economics and SFG Consulting concluded that, compared on this basis, it is clear that the market evidence is consistent with a regulatory margin of 5 per cent.

9.7 CONCLUSION ON RETAIL MARGIN

Based on the available evidence, we consider that the following net retail margins are appropriate:

- for non-contestable customers, a retail margin of 3 per cent.
- for contestable customers, a retail margin of 5 per cent.

9.7.1 Non-contestable customers

For non-contestable customers, the recommended retail margin is based primarily on benchmarks from other jurisdictions. At the commencement of the forecast period, the most relevant benchmarks are from those jurisdictions in which volume risk and/or energy purchase risk are not a significant factor. These jurisdictions include NSW (prior to the 2007 Determination and the phasing-out of the ETEF), the ACT in 2003 (when energy purchase risk was incorporated in the allowance for wholesale costs) and Tasmania. The range for retail margin across these various jurisdictions is from 1.5 per cent to 3 per cent. Of these benchmarks, the most relevant is Tasmania, where the incumbent retailer's exposure to both volume risk and energy purchase risk is limited (because FRC has not been introduced and because a Vesting Contract is in place). The retail margin adopted by OTTER is 3 per cent.

It is also appropriate that the retail margin for tariffs for which volume risk and/or energy purchase risk are not a significant factor should be below the retail margin that is observed in the market for businesses that face both volume risk and energy purchase risk. The market evidence suggests that the retail margin for business exposed to volume risk and/or energy purchase risk is in the range of 5 per cent, providing support to the appropriateness of a 3 per cent margin for non-contestable customers.

It should also be noted that Synergy is currently provided with a low "efficient" retail margin for volumes traded under the Vesting Contract.

9.7.2 Contestable customers

For contestable customers, the recommended retail margin is based on both benchmarks from other jurisdictions and other market evidence.

The most relevant benchmarks for contestable customers and those jurisdictions in which retailers are faced with both volume risk and energy purchase risk. These include South Australia, Victoria, and the most recent decisions from NSW, Queensland and the ACT. The range for retail margin across these various jurisdictions is from 4 per cent up to 8 per cent, with most regulators adopting a retail margin of 5 per cent.

The market evidence, suggests that retailers in other jurisdictions earn a retail margin across their customer base (including large and small customers) that is equivalent to a retail margin, as defined for the purposes of this report, of 5 per cent.

10 Retail tariffs

In order to determine regulated retail tariffs, the various costs of supply that a retailer faces in serving customers under a particular tariff are converted into a set of prices that reflect these costs. These prices can be structured in many different ways, including different combinations of fixed and variable tariffs, inclining block tariffs and time of use tariffs.

This section sets out cost reflective tariffs for each of the regulated tariffs in the SWIS, for each year to 2011/12. Cost reflective tariffs for non-contestable tariffs are not presented for 2008/09, reflecting the a commitment not to increase tariffs to small use customers before 2009/10.

In the first instance, this section provides an overview of the various elements of the R component of retail tariffs, as considered in Section 5 through Section 9. Each of these cost elements is incorporated into the R component of tariffs. In addition, network losses are applied to the electricity-related cost elements. Transmission and distribution loss factors, by network tariff type, are determined by Western Power and published on the IMO's website. We have used the most recent estimates of transmission and distribution loss factors for 2008/09.[50] Loss factors are reported for network tariffs. The loss factors for retail tariffs are determined by averaging the loss factors for network tariffs according to the amount of energy for the retail tariff that is supplied under each network tariff.[51]

This section then sets out retail tariffs that reflect these various cost elements. Note that the retail tariffs set out in this section refer only to the R component of retail tariffs. As discussed in more detail in Section 11 and Section 12, the N

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[50] The SWIN average transmission loss factor for 2008/09 is 1.0418. The distribution loss factors for 2008/09 are set out below:

Network tariff	Distribution loss factor
A1 - Anytime Energy (Residential)	1.0817
A2 - Anytime Energy (Business)	1.0463
A3 - Time of Use Energy (Small)	1.0817
A4 - Time of Use Energy (Large)	1.0463
A5 - High Voltage Metered Demand	1.0217
A6 - Low Voltage Metered Demand	1.0345
A7 - High Voltage Contract Maximum Demand	1.0055
A9 - Streetlighting	1.0817
A10 - Un-metered Supplies	1.0817

See IMO's website: http://www.imowa.com.au/10_5_1_l_loss_factors.htm

For the purposes of Frontier Economics' draft recommendations report, estimates of transmission and distribution loss factors for 2007/08 were used, since the 2008/09 estimates were not then available.

51 The estimated loss factors for retail tariffs are as follows:

Retail tariff	Loss factor
A1, B1, Streetlight, W1	1.13
K1, L1, L3, M1, R1, R3,	1.09
S1	1.07
T1	1.06

component of retail tariffs is regulated by the ERA, and this N component must also be included when considering the total bill that a customer will face.

Finally, this section considers the structure of retail tariffs. It is important to note that there are various options for structuring retail tariffs that are consistent with a retailer recovering the total costs that they face in serving customers on particular tariffs. There are both economic principles and policy objectives that can guide the choice of a tariff structure. In determining the structure of retail tariffs in this section, the existing tariff structure is adopted as a base case. In general, at this stage the available evidence on the characteristics of customer load is insufficient to justify significant changes to the existing tariff structures. In the future, if more information on the load characteristics of customers becomes available, or in the event that smart meters are rolled out in Western Australia, the structure of tariffs should be revisited.

10.1 A1 TARIFF

A summary of the various R components of the A1 tariff is provided in Table 13.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	89.31	90.42	91.47	88.94
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	75.00	75.00	75.00	75.00
Retail margin	%	3	3	3	3

Table 13: R components of the A1 tariff (real 2007/08, excluding network losses)

As discussed in Section 4, the existing A1 tariff includes a fixed component and a variable component. Retaining this tariff structure, including the relationship between the fixed component and the variable component of the existing A1 tariff, the R component of the A1 tariff for each year to 2011/12 is set out in Table 14.

		2008/09	2009/10	2010/11	2011/12
Fixed charge	c/day	-	0.81	0.82	0.80
Metered rate	c/kWh	-	12.48	15.00	14.99

Table 14: A1 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

An alternative structure that could be considered for the A1 tariff is an inclining block tariff. Inclining block tariffs can be appropriate from an economic perspective where large users tend to use a greater proportion of their total electricity during peak periods. Where this is the case, an inclining block tariff can be used to provide signals to large users that reflect the greater scarcity of generation and network capacity during those periods in which they use a greater proportion of their energy.

The available evidence does not support the view that large users in Western Australia consume a greater proportion of their total electricity during peak times of the year. In fact, data provided by Synergy indicates the opposite. Patterns of consumption across the year are very similar for most customers on the A1 tariff, with the exception of customers with the lowest annual consumption. Customers with the lowest annual consumption tend to consume a greater proportion of their total annual consumption during peak summer months. All other classes of customers have almost identical patterns of consumption across the year. In short, this data does not provide an economic justification for introducing an inclining block tariff.

Nevertheless, it may be the case that large residential consumers tend to consume a larger proportion of their total electricity during peak hours of the day. The information provided by Synergy does not have sufficient detail on consumption during peak and off-peak periods of the day to determine whether this is the case. In the event that smart meters are rolled out in Western Australia, more detailed data on consumption patterns of residential customers will be available, and the appropriate structure of tariffs for residential customers should be revisited.

10.2 B1 TARIFF

A summary of the various R components of the B1 tariff is provided in Table 15.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	-	-	-	-
Green energy – carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy – MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	-	-	-	-
Retail margin	%	3	3	3	3

Table 15: R components of the B1 tariff (real 2007/08, excluding network losses)

In regard to the black energy component, Frontier Economics does not have half-hourly load data for customers on the B1 tariff. In the absence of load data we have assumed that the energy price for the B1 tariff will be equivalent to the energy price for the streetlight tariffs (discussed in Section 10.12), on the basis that energy for the B1 tariff and the streetlight tariffs are supplied during similar off-peak times. This forecast energy price is confidential and so has not been included in Table 15.

In regard to the retail operating cost component, there is a lack of publicly available benchmark information on retail operating costs for off-peak hot water services. As a result, Frontier Economics has inferred an amount for retail operating costs from aggregate data provided by Synergy. Since customers on the B1 tariff are, in almost all cases, also on the A1 tariff, a number of the activities associated with retail operating costs – including customer management and general overheads – need not be duplicated for the B1 tariff. However, because customers on the B1 tariff have a second meter for that tariff, there will be additional data management and billing costs. The allowance for retail operating costs for the B1 tariff is therefore an estimate of that component of the retail operating costs of non-contestable customers that relate to data management and billing costs. Since this estimate is based on information provided by Synergy on a confidential basis, it has not been included in Table 15.

As discussed in Section 4, the existing B1 tariff includes a fixed component and a variable component. However, the fixed component of the B1 retail tariff is currently set below the fixed component of the network tariff that these customers are required to pay. This implies that the fixed change of the R

component of the B1 tariff is effectively negative. This is not an appropriate tariff structure. Rather than retain this tariff structure, therefore, the R component of the B1 tariff will be structured so that the fixed component of retail operating costs (which is estimated at 75 per cent) will be recovered through the fixed charge, and all other variable costs will be recovered through the metered rate. Reflecting this tariff structure, the R component of the A1 tariff for each year to 2011/12 is set out in Table 16.

		2008/09	2009/10	2010/11	2011/12
Fixed charge	c/day	-	3.76	3.79	3.84
Metered rate	c/kWh	-	6.87	9.28	9.58

Table 16: B1 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

10.3 K1 TARIFF

A summary of the various R components of the K1 tariff is provided in Table 17.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	89.21	90.27	91.27	88.49
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	75.00	75.00	75.00	75.00
Retail margin	%	3	3	3	3

Table 17: R components of the K1 tariff (real 2007/08, excluding network losses)

As discussed in Section 4, the existing K1 tariff includes a fixed component and a variable block component. The existing tariff structure is part inclining block tariff and part declining block tariff: although in practice, no customers on the K1 tariff consume in excess of 1,650 kWh per day (the threshold for the third, declining, variable block component). Retaining this tariff structure, including the relationship between the fixed component and the variable components of the existing K1 tariff, the R component of the K1 tariff for each year to 2011/12 is set out in Table 18.

		2008/09	2009/10	2010/11	2011/12
Fixed charge	c/day	-	0.79	0.80	0.79
Metered rate (≤ 20 kWh pd)	c/kWh	-	10.41	12.84	12.84
Metered rate (next 1,630 kWh pd)	c/kWh	-	14.75	17.24	17.15
Metered rate (> 1,650 kWh pd)	c/kWh	-	-	-	-

Table 18: K1 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

10.4 L1 AND L3 TARIFFS

As discussed, this report deals with the L1 tariff on the basis that the existing L1 tariff is split between customers consuming above and below the threshold for contestability. The new L1 tariff is restricted to customers consuming below the threshold for contestability. The new L3 tariff is restricted to customers consuming above the threshold for contestability.

In determining the R component of the new L1 tariff, the costs set out in the draft recommendations report remain appropriate, since these costs were determined on the basis that the majority of L1 customers are non-contestable. A summary of the R components of the new L1 tariff is provided in Table 19.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	89.13	90.14	91.09	88.10
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	75.00	75.00	75.00	75.00
Retail margin	%	3%	3%	3%	3%

Table 19: R components of the new L1 tariff (real 2007/08, excluding network losses)

In determining the R component of the new L3 tariff, however, several changes to cost inputs are made:

- The black energy cost is based solely on LRMC, rather than on a combination of LRMC and the Verve sustainable energy price. This reflects the fact that customers on the new L3 tariff will be contestable.
- The retail operating cost is equivalent to the retail operating cost for the R3 tariff, reflecting the greater retail operating costs associated with these larger contestable customers.
- The retail margin is equivalent to the retail margin for the R3 tariff, reflecting the greater risk associated with these larger contestable customers.

A summary of the various R components of the new L3 tariff is provided in Table 20.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	100.46	103.56	96.75	95.40
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	700.00	700.00	700.00	700.00
Retail margin	%	5	5	5	5

Table 20: R components of the new L3 tariff (real 2007/08, excluding network losses)

As discussed in Section 4, the existing L1 tariff includes a fixed component and a variable block component. The existing L1 tariff is a declining block tariff.

Retaining the existing L1 tariff structure, including the relationship between the fixed component and the variable components of the existing L1 tariff, the R component of the new L1 tariff for each year to 2011/12 is set out in Table 21. Because average consumption of customers on the new L1 tariff is significantly lower than average consumption of customers on the existing L1 tariff, the R component of the new L1 tariff is higher than the R component of the existing L1 tariff. Since no customers on the new L1 tariff have consumption in excess of 1,650 kWh per day, there is no need for a tariff rate for this consumption.

		2008/09	2009/10	2010/11	2011/12
Fixed charge	c/day	-	1.58	1.60	1.56
Metered rate (≤ 1,650 kWh pd)	c/kWh	-	11.55	13.99	13.95
Metered rate (> 1,650 kWh pd)	c/kWh	-	-	-	-

Table 21: New L1 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

Retaining this tariff structure, including the relationship between the fixed component and the variable components of the existing L1 tariff, the R component of the new L3 tariff for each year to 2011/12 is set out in Table 22. Because the cost of serving customers on the new L3 tariff is greater than the

cost of serving customers on the existing L1 tariff, the R component of the new L3 tariff is higher than the R component of the existing L1 tariff.

		2008/09	2009/10	2010/11	2011/12
Fixed charge	c/day	1.75	1.81	1.72	1.71
Metered rate (≤ 1,650 kWh pd)	c/kWh	12.77	13.26	14.87	15.04
Metered rate (> 1,650 kWh pd)	c/kWh	10.95	11.37	13.09	13.26

Table 22: New L3 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

10.5 M1 TARIFF

A summary of the various R components of the M1 tariff is provided in Table 23.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	102.17	105.35	98.38	97.02
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	700.00	700.00	700.00	700.00
Retail margin	%	5	5	5	5

Table 23: R components of the M1 tariff (real 2007/08, excluding network losses)

As discussed in Section 4, the existing M1 tariff includes a fixed component and a variable block component. The existing M1 tariff is a declining block tariff. Retaining this tariff structure, including the relationship between the fixed component and the variable components of the existing M1 tariff, the R component of the M1 tariff for each year to 2011/12 is set out in Table 24.

		2008/09	2009/10	2010/11	2011/12
Fixed charge	c/day	1.97	2.05	1.93	1.92
Metered rate (≤ 1,650 kWh pd)	c/kWh	13.67	14.21	15.74	15.90
Metered rate (> 1,650 kWh pd)	c/kWh	11.61	12.07	13.72	13.89

Table 24: M1 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

10.6 R1 TARIFF

A summary of the various R components of the R1 tariff is provided in Table 25.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	89.27	90.36	91.39	88.78
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	75.00	75.00	75.00	75.00
Retail margin	%	3	3	3	3

Table 25: R components of the R1 tariff (real 2007/08, excluding network losses)

As discussed in Section 4, the existing R1 tariff includes a fixed component and peak and off-peak variable components. Retaining this tariff structure, including the relationship between the fixed component and the variable components of the existing R1 tariff, the R component of the R1 tariff for each year to 2011/12 is set out in Table 26.

		2008/09	2009/10	2010/11	2011/12
Fixed charge	c/day	-	82.76	83.87	81.93
Peak energy rate	c/kWh	-	15.21	17.69	17.56
Off-peak energy rate	c/kWh	-	5.15	7.50	7.60

Table 26: R1 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

10.7 R3 TARIFF

A summary of the various R components of the R3 tariff is provided in Table 27.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	102.47	105.66	98.67	97.31
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	700.00	700.00	700.00	700.00
Retail margin	%	5	5	5	5

Table 27: R components of the R3 tariff (real 2007/08, excluding network losses)

As discussed in Section 4, the existing R3 tariff includes a fixed component and peak and off-peak variable components. Retaining this tariff structure, including the relationship between the fixed component and the variable components of the existing R3 tariff, the R component of the R3 tariff for each year to 2011/12 is set out in Table 28.

		2008/09	2009/10	2010/11	2011/12
Fixed charge	c/day	102.74	106.31	100.12	99.36
Peak energy rate	c/kWh	18.61	19.28	20.48	20.56
Off-peak energy rate	c/kWh	5.97	6.20	8.17	8.34

Table 28: R3 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

10.8 S1 TARIFF

A summary of the various R components of the S1 tariff is provided in Table 29.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	100.73	103.84	97.00	95.65
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	2,000.00	2,000.00	2,000.00	2,000.00
Retail margin	%	5	5	5	5

Table 29: R components of the S1 tariff (real 2007/08, excluding network losses)

As discussed in Section 4, the existing S1 tariff includes a demand charge, peak and off-peak energy charges and a minimum charge. Retaining this tariff structure, including the relationship between the various components of the existing S1 tariff, the R component of the S1 tariff for each year to 2011/12 is set out in Table 30.

		2008/09	2009/10	2010/11	2011/12
Minimum charge	$/day	258.81	267.83	251.83	249.72
Demand rate	c/kW/day	69.50	71.92	67.62	67.05
Peak energy rate	c/kWh	6.82	7.08	9.00	9.17
Off-peak energy rate	c/kWh	3.16	3.29	5.44	5.64

Table 30: S1 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

10.9 T1 TARIFF

A summary of the various R components of the T1 tariff is provided in Table 31.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	101.63	104.78	97.87	96.51
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Retail operating costs	$/customer	2,000.00	2,000.00	2,000.00	2,000.00
Retail margin	%	5	5	5	5

Table 31: R components of the T1 tariff (real 2007/08, excluding network losses)

As discussed in Section 4, the existing T1 tariff includes a demand charge, peak and off-peak energy charges and a minimum charge. Retaining this tariff structure, including the relationship between the various components of the existing T1 tariff, the R component of the T1 tariff for each year to 2011/12 is set out in Table 32.

		2008/09	2009/10	2010/11	2011/12
Minimum charge	$/day	353.69	365.83	343.50	340.27
Demand rate	c/kW/day	69.06	71.43	67.07	66.44
Peak energy rate	c/kWh	7.37	7.64	9.45	9.60
Off-peak energy rate	c/kWh	3.99	4.15	6.17	6.35

Table 32: T1 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

10.10 P2 TARIFF

The P2 tariff is a tariff for supply to Commonwealth and foreign Government instrumentalities in Horizon Power's North West Integrated System. For an average customer on the P2 tariff, the average bill would be the same whether the customers were on the existing P2 tariff or on the existing L1/L2 tariff. For this reason, the P2 tariff rates will be adjusted to reflect the tariff rates under the existing L1/L2 tariff. Since the L1 tariff has now been split into split L1 and L3 tariffs, there is a question as to which of these is most appropriate. Since customers on the P2 tariff are generally large customers and in excess of the threshold of 50 MWh per annum, the L3 tariff is the more appropriate benchmark. Under this approach, the R component of the P2 tariff for each year to 2011/12 is set out in Table 33.

		2008/09	2009/10	2010/11	2011/12
Fixed charge	c/day	1.75	1.81	1.72	1.71
Metered rate (≤ 1,650 kWh pd)	c/kWh	12.77	13.26	14.87	15.04
Metered rate (> 1,650 kWh pd)	c/kWh	10.95	11.37	13.09	13.26

Table 33: P2 tariff (real 2007/08, excluding GST)

10.11 W1 TARIFF

A summary of the various R components of the W1 tariff is provided in Table 34.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	77.45	81.68	72.58	70.88
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Gross retail margin	%	5%	5%	5%	5%

Table 34: R components of the W1 tariff (real 2007/08, excluding network losses)

In contrast to the R components of other regulated tariffs, the R component of the W1 tariff and the streetlight tariffs do not include separate line items for retail operating costs and retail margin. Rather, the W1 tariff and the streetlight tariffs have a single line item representing the gross retail margin. The reason for the different approach is that the retail supply of electricity for traffic lights and streetlights involves a different range of activities to the retail supply of electricity for other tariffs. In particular, the retail supply of electricity for traffic lights and streetlights tends to involve the supply of significant loads to only one, or a few, customers. As a result, the retailing activities required for the supply of electricity to customers on other tariffs – including customer information systems, customer management and marketing – tend to be different to those required for traffic lights and streetlights.

This leaves the question of the appropriate gross retail margin to adopt for the W1 tariff and the streetlight tariffs. Since there is likely to be little volume risk or energy purchase risk associated with the W1 tariff and the streetlight tariffs – because these loads are predictable and are predominantly off-peak – we consider that a net retail margin of at most 3 per cent is appropriate to these tariffs. Including an allowance for retail operating costs, we have adopted a gross retail margin of 5 per cent. We note that no information on the retail operating costs or retail margin for the W1 or streetlight tariffs was provided during the public consultation period for this Review. In the absence of detailed cost information, we consider that a gross retail margin of 5 per cent is appropriate.

As discussed in Section 4, the existing W1 tariff consists of a fixed charge per kW per day. Retaining this tariff structure, the R component of the W1 tariff for each year to 2011/12 is set out in Table 35.

		2008/09	2009/10	2010/11	2011/12
Tariff rate	c/kW/day	230.71	244.68	277.04	278.71

Table 35: W1 tariff with existing structure (real 2007/08, excluding GST)

Note: Green wholesale costs are recovered entirely through the metered rate.

10.12 STREETLIGHT TARIFFS

A summary of the various R components of streetlight tariffs is provided in Table 36.

		2008/09	2009/10	2010/11	2011/12
Black energy	$/MWh	-	-	-	-
Green energy - carbon	$/MWh	0.00	0.00	19.82	21.23
Green energy - MRET	$/MWh	0.78	0.97	1.44	1.95
Ancillary services	$/MWh	1.15	1.15	1.15	1.15
Market fees	$/MWh	0.47	0.47	0.47	0.47
Gross retail margin	%	5%	5%	5%	5%

Table 36: R components of streetlight tariffs (real 2007/08, excluding network losses)

As with the W1 tariff, a 5 per cent gross retail margin for the streetlight tariffs is considered to be appropriate.

Half-hourly load data was not available for either the traffic lights tariff or the streetlight tariffs. For the traffic lights tariff, this was not a significant problem because the load for traffic lights can be assumed to be flat over the year. However, the load for streetlight tariffs cannot be assumed to be flat over the year: streetlights are only on during the night, and will have different switch-on times and switch-off times during the year. Different streetlights also have different switch-off times: midnight, 1:15 am or dawn.

In the absence of load data we have adopted a forecast energy price for the streetlight tariffs that has been provided to the OOE by Synergy. This forecast energy price is confidential and so has not been included in Table 36. However, we do note that the forecast energy price for the streetlight tariffs is significantly lower than that for the W1 tariff. This is to be expected, since a greater proportion of the total load for streetlights will occur during off-peak periods over night, compared with traffic lights which operate 24 hours a day.

As discussed in Section 4, the existing streetlight tariffs include a range of different rates per day for streetlights of different wattage, type and operation time. The average increase in these tariffs, reflecting both the R component and the N component of tariffs,[52] is set out in Table 37.

[52] In considering the N component of tariffs, the assumed change in network tariffs is as set out in Network Scenario One, as discussed in Section 11

		2008/09	2009/10	2010/11	2011/12
Increase in tariff	%	21.39%	28.52%	25.56%	18.38%

Table 37: Increase in streetlight tariffs (real)

11 Network tariffs

Network tariffs – including both transmission and distribution tariffs – for the South West Interconnected Network (SWIN) are regulated by the ERA. The appropriate level of network tariffs is beyond the scope of this review.

However, network costs are an important component of the cost of supplying customers on regulated tariffs, and customers should therefore face these costs. We consider that the appropriate approach is to treat network tariffs as a pass through. This was supported almost universally by stakeholders responding to the OOE's Issues Paper. This is also consistent with the approach adopted in other jurisdictions.

With network tariffs determined independently by the ERA, there is necessarily some uncertainty as to the total bill that customers on regulated tariffs will face over the period to 2011/12. While the R component of tariffs (black and green wholesale costs, market fees and ancillary services, retail costs and retail margin) is set out in this report, the N component of tariffs (network charges) will be determined by the ERA. The current access arrangement for the SWIN extends to the end of 2008/09, with a new access arrangement to be introduced from 2009/10.

This uncertainty in regard to future network tariffs is most relevant to the consideration of the impact on customers' bills of changes to retail tariffs. In comparing the existing regulated tariffs with the tariffs that will apply over the period from 2008/09 to 2011/12, it is necessary to compare existing regulated tariffs with the total tariffs they will face over the period from 2008/09 to 2011/12 – that is, including both the R component and the N component.

As part of this review the OOE is considering the funding arrangements by which Horizon Power is provided with financial support to cover the differential between tariff revenue and costs, and is considering providing this funding through means other than network tariffs. Reflecting this possibility, we examine the impact on customers' bills of changes to retail tariffs under two scenarios:

- Network Scenario One: network tariffs excluding the TEC component; and
- Network Scenario Two: network tariffs including the TEC component.

This section sets out our approach to estimating the network component of tariffs under each of these scenarios.

11.1 NETWORK TARIFFS UNDER NETWORK SCENARIO ONE

Network tariffs over the period to 2011/12 are based on approved network tariffs for 2008/09 and, beyond that, on expenditure forecasts from Western Power. Since the release of Frontier Economics' draft recommendations report, Western Power has provided updated forecasts of changes in network tariffs over the period 2009/10 to 2011/12, which are based on Western Power's expenditure forecasts. These updated forecasts imply significantly greater

increases in network tariffs than the forecasts provided for the purposes of Frontier Economics' draft recommendations report. These updated forecast changes in network tariffs are set out in Table 38.

	2009/10	2010/11	2011/12
Network tariff increases	39.55%	24.77%	24.83%

Table 38: Forecast changes in network tariffs, excluding the TEC (real)

11.2 NETWORK TARIFFS UNDER NETWORK SCENARIO TWO

As discussed in Section 2, all electricity customers in the SWIS that are connected to the distribution network currently contribute to the TEF through the TEC, which is a component of network charges. If the TEC remains a component of network charges, then the forecast changes in network tariffs will be different to those set out in Table 38.

In order to estimate the impact on customers in the event that the TEC remains a component of network charges, it is necessary to forecast the TEF over the period to 2011/12.

The TEF is effectively the amount of funding that Horizon Power requires to be a sustainable business, earning enough revenue to cover operating costs and an appropriate rate of return on assets. The methodology for estimating the TEF, therefore, is very similar to the methodology for estimating Verve Energy's sustainable energy price, as discussed in Section 5. The cost inputs used to estimate the TEF are based on assumptions for the period to 2011/12 provided by Horizon Power on a confidential basis.

The first step to forecasting the TEF is to estimate Horizon Power's target sustainable revenue. This is based on expenditure forecasts provided by Horizon Power, and includes operational expenditure (including fuel costs, labour costs, operating materials and other expenditure) as well as a return on total assets.

The second step is to estimate Horizon Power's revenue from sales of electricity and from other sources. In considering revenue from sales of electricity, it is necessary to take into account the revenue that Horizon Power would earn under the regulated tariffs set out in Section 10. In order to do this, the tariff increases assumed by Horizon Power in its assumptions were backed out of Horizon Power's forecast revenues from sales of electricity, and replaced with tariff increases resulting from the regulated retail tariffs set out in Section 10 and the network tariff increases under Network Scenario One.

The third step is to deduct forecast revenues from the target sustainable revenue in order to estimate the total revenue shortfall for Horizon Power. This amount is the total amount of the TEF. Taking into account the TEF amount for

2008/09, which has already been determined, the estimates of the TEF from this approach are set out in Table 39.

	2008/09	2009/10	2010/11	2011/12
TEF amount	$72,000,000	$92,246,856	$60,069,580	$35,861,389

Table 39: Forecast TEF amount (nominal)

The final step it to allocate this TEF amount to particular network tariffs and then to particular regulated retail tariffs. The total amount of the TEF is allocated to particular network tariffs on the basis of information from Western Power. The TEF is then allocated to particular retail tariffs based on estimates of the proportion of customers on each network tariff that are on regulated retail tariffs (as opposed to market contracts). This allocation provides an amount in dollars that is an estimate of the amount of the TEF to be recovered from customers on each regulated retail tariff. Adjusting this dollar amount for forecast growth in load (to reflect the fact that the total TEF amount will be recovered over a larger load as the size of the market increases) provides an amount for the TEF to be included in the cost-stack for each regulated tariff.

12 Impact on customers

While this report focuses on the R component of retail tariffs, customers will be concerned with changes in their total bill for electricity. This includes both the R component and the N component of regulated tariffs. In considering the impact on customers, therefore, we consider changes in both the R component and the N component. The result is that we consider the impact on customers under each of the two network scenarios discussed in Section 11.

Customers with different patterns of consumption may be impacted in different ways by movements in tariffs. As a result, there are two ways of considering the impact on customers of moving to cost-reflective tariffs:

- by examining the average change in electricity bills across all customers on a regulated tariff; or
- by examining the change in electricity bills for particular customers on a regulated tariff.

There are two reasons that the impact of new tariffs on particular customers may differ. The first is where tariffs have a significant fixed component and increases in the fixed and variable component are not the same. Where this is the case, the impact on customers may vary with their consumption. However, the fixed component of retail electricity tariffs tends to be a relatively small component of total customer bills, except for customers with very low consumption. Furthermore, for each of the regulated tariffs, both the fixed and variable components of tariffs will increase. As a result, our analysis indicates that impacts on customers tend not to differ substantially with the customers' level of consumption.

The second reason that the impact of new tariffs may differ across customers is where a new tariff structure is adopted. For instance, a change from a flat tariff to either an inclining or declining block tariff will impact on different customers in different ways, depending on customers' consumption. Since the tariff structures set out in Section 10 generally adopt the existing tariff structure, the impact of new tariffs will not vary substantially with customers' level of consumption as a result of changes in the tariff structure.

For these reasons, in the sections that follow, we focus on the average change in electricity bills across all customers in examining the impact on customers of moving to cost reflective retail tariffs. We examine each of the regulated tariffs, and each year to 2011/12. The estimates of the impact on customers on non-contestable tariffs will take into account a commitment not to increase retail tariffs for small use customers before 2009/10. For those tariffs that have not increased in 2008/09 according to the tariff by-laws, the increase in 2009/10 is shown relative to 2007/08.

We examine the impact on customers in nominal terms, assuming inflation rates based on lagged CPI data and lagged inflation forecasts from the Western

Australian Department of Treasury and Finance.[53] Assumed inflation rates are set out in Table 40.

	2008/09	2009/10	2010/11	2011/12
Inflation rate	4.30%	3.25%	3.00%	2.75%

Table 40: Assumed inflation rates

12.1 A1 TARIFF

The average change in electricity bills across all customers on the A1 tariff is set out in Table 41.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	51.82%	25.63%	12.66%
Including TEC	-	59.36%	22.70%	11.33%

Table 41: Average impact across all customers for A1 tariff (nominal)

12.2 B1 TARIFF

The average change in electricity bills across all customers on the B1 tariff is set out in Table 42.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	131.55%	32.02%	18.59%
Including TEC	-	144.72%	28.35%	16.98%

Table 42: Average impact across all customers for B1 tariff (nominal)

[53] Assumed inflation rates are lagged to reflect the fact that in adjusting tariffs to reflect inflation each year, historical data will most likely be relied upon.

12.3 K1 TARIFF

The average change in electricity bills across all customers on the K1 tariff is set out in Table 43.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	50.17%	26.50%	13.72%
Including TEC	-	57.17%	23.70%	12.45%

Table 43: Average impact across all customers for K1 tariff (nominal)

12.4 L1 TARIFF

The average change in electricity bills across all customers on the L1 tariff is set out in Table 44.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	29.10%	26.36%	13.72%
Including TEC	-	35.02%	23.62%	12.47%

Table 44: Average impact across all customers for L1 tariff (nominal)

The lower increase in the average bill for customers on the L1 tariff compared to customers on the A1 and K1 tariff is a result of the relatively high existing tariff. The existing rate for the first variable consumption block is 17.47 c/kWh, and almost all consumption on the L1 tariff falls within this first variable consumption block.

12.5 L3 TARIFF

The average change in electricity bills across all customers on the L3 tariff is set out in Table 45.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	39.05%	20.33%	13.30%
Including TEC	-	45.46%	17.83%	12.00%

Table 45: Average impact across all customers for L3 tariff (nominal)

12.6 M1 TARIFF

The average change in electricity bills across all customers on the M1 tariff is set out in Table 46.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	50.72%	20.45%	13.36%
Including TEC	-	57.80%	17.90%	12.03%

Table 46: Average impact across all customers for M1 tariff (nominal)

12.7 R1 TARIFF

The average change in electricity bills across all customers on the R1 tariff is set out in Table 47.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	37.25%	26.68%	10.39%
Including TEC	-	41.61%	24.74%	9.57%

Table 47: Average impact across all customers for R1 tariff (nominal)

For the R1 tariff, the impact on the electricity bills of particular customers will depend on the customers' peak and off-peak consumption. Assuming that a customer has a typical split between peak and off-peak consumption, the impacts set out in Table 47 is representative of the customer impact.

12.8 R3 TARIFF

The average change in electricity bills across all customers on the R3 tariff is set out in Table 48.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	4.99%	42.19%	18.91%	10.63%
Including TEC	4.99%	46.29%	17.36%	9.83%

Table 48: Average impact across all customers for R3 tariff (nominal)

For the R3 tariff, the impact on the electricity bills of particular customers will depend on the customers' peak and off-peak consumption. Assuming that a customer has a typical split between peak and off-peak consumption, the impacts set out in Table 47 is representative of the customer impact.

12.9 S1 TARIFF

The average change in electricity bills across all customers on the S1 tariff is set out in Table 49.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	5.01%	26.96%	19.12%	10.17%
Including TEC	5.01%	30.92%	17.44%	9.32%

Table 49: Average impact across all customers for S1 tariff (nominal)

12.10 T1 TARIFF

The average change in electricity bills across all customers on the T1 tariff is set out in Table 50.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	5.01%	35.09%	18.61%	9.27%
Including TEC	5.01%	39.54%	16.86%	8.38%

Table 50: Average impact across all customers for T1 tariff (nominal)

12.11 P2 TARIFF

The average change in electricity bills for the P2 tariff is set out in Table 51.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	39.05%	20.33%	13.30%
Including TEC	-	45.46%	17.83%	12.00%

Table 51: Average impact across all customers for P2 tariff (nominal)

12.12 W1 TARIFF

The average change in electricity bills for the W1 tariff is set out in Table 52.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	141.75%	19.88%	10.35%
Including TEC	-	159.03%	16.13%	8.45%

Table 52: Average impact for W1 tariff (nominal)

12.13 STREETLIGHT TARIFFS

The average change in electricity bills for the streetlight tariffs is set out in Table 53.

	2008/09	2009/10	2010/11	2011/12
Excluding TEC	-	62.77%	31.44%	22.62%
Including TEC	-	68.01%	29.33%	21.63%

Table 53: Average impact for streetlight tariffs (nominal)

13 Future tariff adjustments

Electricity tariffs in Western Australia have remained unchanged for some time. Until July 2007, business tariffs had not increased in nominal terms since 1991/92. Residential tariffs have not increased since 1997/98 (with the exception of the introduction of the GST). This reflects, at least in part, the absence of a formal process for regular reviews of electricity tariffs in Western Australia.

The lack of a formal process for regular tariff reviews imposes significant regulatory uncertainty on both businesses and consumers. This regulatory uncertainty has implications for investment decisions by businesses, potentially leading to inefficient patterns of investment in both the retail and generation sectors. Uncertainty also has implications for decisions by consumers, including their ability to adjust to changes in electricity tariffs.

One way to provide greater certainty to investors and consumers is to put in place a formal process for regular reviews of electricity tariffs. There are several possible approaches. The OOE's Issues Paper proposed four possible review processes:

- The OOE is given responsibility for periodically reviewing tariffs and advising the Minister for Energy as to the appropriate tariff arrangements, with the Minister to be responsible for the final determination of tariffs.
- An independent authority (such as the ERA) is given responsibility for periodically reviewing tariffs and advising the Minister for Energy as to the appropriate tariff arrangements, with the Minister to be responsible for the final determination of tariffs.
- An independent authority (such as the ERA) is given responsibility for periodically reviewing and setting tariffs.
- Implementation of mechanical arrangements to annually adjust tariff levels, with regular review of the tariff adjustment mechanism by the Minister for Energy or an independent authority.

In considering the appropriate process, there are several questions to be addressed. First, are mechanical arrangements to annually adjust tariff levels appropriate? Second, what is the appropriate timing for the tariff review process? Third, who should be responsible for conducting the tariff review process?

In addressing these questions, it is important to bear in mind the purpose of tariff regulation: while terms of reference vary, it is almost always the case that a key objective of tariff regulation is the achievement of cost-reflective tariffs.

13.1 MECHANICAL ARRANGEMENTS FOR ANNUAL ADJUSTMENTS

An arrangement to mechanically adjust tariff levels each year may be the preferred approach where changes in costs are stable and predictable, or where changes in costs are closely related to some transparent external benchmark. Neither of these is true in the case of regulated electricity tariffs.

First, the costs of supplying electricity to retail customers can be subject to significant movements in costs, which are difficult to forecast. This is particularly the case for the wholesale electricity market, which can be subject to significant movements. For instance, drought conditions on the east coast recently led to substantial increases in wholesale electricity prices across the NEM, largely as a result of water restrictions imposed on generators in south-east Queensland. With the easing of these water restrictions, electricity prices in the NEM are returning to levels seen before the imposition of water restrictions. Variations in fuel costs can also lead to significant changes in wholesale electricity prices.

Second, the costs of supplying electricity to retail customers can vary to reflect any of a wide range of cost inputs. For instance, changes in capital costs or fuel costs for generation plant, new climate change policies and changes in network infrastructure investment can all have a substantial impact on the total cost of supplying electricity to retail customers. In some markets, transparent external benchmarks such as forward prices for electricity prices might provide a basis for mechanically adjusting at least the wholesale cost component of retail tariffs (which is likely to be a key source of cost changes over the regulatory period in any case). However, there is no transparent contract price in Western Australia that could be used for that purpose. The fact that there are separate markets for energy and capacity further complicates the establishment of an appropriate cost benchmark in Western Australia.

In the absence of predictable costs or an external benchmark that adequately captures each of the cost inputs into the retail supply of electricity, a regular review of tariffs is likely to lead to tariffs that are more closely reflective of tariffs. Nevertheless, an annual adjustment of tariffs in line with an index designed to reflect the costs of supplying electricity would be preferable to keeping tariffs constant in nominal terms. Frontier Economics and the OOE will give further consideration to the development of an index to reflect the costs of supplying electricity.

13.2 TIMING OF THE TARIFF REVIEW PROCESS

In determining the appropriate timing for the tariff review process, it is necessary to balance the objective of providing certainty to investors and consumers with the objective of ensuring that tariffs are cost reflective. A longer regulatory period provides greater certainty to investors and consumers but, in the process, increases the likelihood that forecast costs will diverge from actual costs.

In the interests of regulatory certainty, a regulatory period in excess of one-year is desirable. A multi-year regulatory period provides both businesses and consumers with greater certainty as to future regulated tariffs than would a single-year regulatory period.

In the interests of achieving cost reflective tariffs, however, the regulatory period should not be too long. As discussed, the costs of supplying electricity to retail customers can be subject to significant movements in costs, which are difficult to forecast. A regulatory period that is too long, therefore, becomes increasingly likely to result in tariffs that are not cost reflective, with the result that either

retailers are required to supply electricity at prices below their efficient costs, or customers are required to purchase electricity at prices in excess of efficient costs.

We consider that the best balance between providing regulatory certainty and achieving cost-reflectivity is provided by a regulatory period of two to three years. Generally speaking, costs can be more accurately forecast over a period of two to three years. The reason is that there is greater certainty about major developments such as regulatory changes and investment in new infrastructure over this period than there is over a longer period. Nevertheless, since there can be significant changes to the costs faced by retailers over this period, we consider that a regulatory period of this length should include a mechanism for the pass through of costs resulting from unforeseen changes to the market or the regulatory environment.

A multi-year regulatory period is consistent with the majority of views expressed in response to the OOE's Issues Paper.

A multi-year regulatory period is also consistent with the approach in most other jurisdictions:

- In New South Wales, IPART's most recent retail price determination extends for three years, although with an annual review of wholesale energy costs to determine whether costs have changed by more than 10 per cent.
- In South Australia, ESCOSA's most recent determination extends for three years.
- In Tasmania, OTTER's most recent determination extends for two and a half years.
- In the ACT, the ICRC's 2003 determination provided for a three-year regulatory period, immediately following the introduction of FRC. These regulatory arrangements have since been extended for two one-year periods as the Treasurer considers whether regulated retail prices remain necessary.

The clear exception is Queensland. Following the introduction of FRC last year, the QCA assessed the Benchmark Retail Cost Index (BRCI) for 2007/08, and is currently in the process of assessing the BRCI for 2008/09.

It is also worth considering whether the timing of the retail tariff review process should coincide with the timing of the network tariff review process. In principle, there is some reason to favour undertaking retail tariff reviews and network tariff reviews concurrently. While cost-reflective retail tariffs and cost-reflective network tariffs can be determined independently of each other, the overall impact of changes to tariffs on customers cannot be determined without considering both the retail component and the network component of tariffs. Conducting the reviews concurrently, therefore, can provide greater certainty to consumers. Also, where there is reason to favour a glide path towards cost-reflectivity, the appropriate glide-path can more easily be identified with knowledge of changes to the costs of both the retail component and the network component of tariffs.

Against this, however, are practical considerations. In particular, it is often appropriate for the timing of tariff reviews to reflect changes to the market or

regulatory environment. For instance, where a significant and unexpected change impacting on the costs of supplying regulated services occurs during a regulatory period, it may be appropriate to conduct a mid-term review or a new pricing determination. If it is one of the retail or network businesses that is affected, but not the other, then there may be no reason to conduct a new pricing determination for both services. It may also be the case that the appropriate regulatory period for retail tariffs and network tariffs differs as a result of differing degrees of forecasting certainty.

The second practical consideration is resourcing issues associated with undertaking retail tariff and network tariff reviews concurrently. Tariff reviews are often substantial and time-consuming projects, both for regulators and businesses. If the same regulator is responsible for both determinations, there are likely to be benefits to assigning the same staff to both determinations. From a resourcing perspective, therefore, it may make sense to undertake the two determinations separately.

On balance, and subject to the regulator being sufficiently well resourced, we consider that there is benefit to aligning the review processes for retail and network tariffs, at least initially.

13.3 RESPONSIBILITY FOR THE TARIFF REVIEW PROCESS

Reviewing and determining tariffs is generally the responsibility of either an independent regulator or a Government department. The OOE's Issues Paper considers this in suggesting the OOE and the ERA as alternatives for the tariff review process.

We consider that there are several reasons to favour tariff regulation by an independent economic regulator, which is responsible for determination of tariffs (as opposed to being responsible for making recommendations to the Minister).

First, independent regulation can provide for greater public input into the key issues and debates concerning regulation. Independent regulators often have skills and experience in conducting public processes, including ensuring transparency and fostering debate.

Second, independent regulation may provide greater regulatory certainty. Independent regulators are less likely to be subject to changes in political policy that affect Government and non-independent regulators.

Third, independent regulation offers the opportunity to consolidate relevant regulatory and economic expertise within a single agency. This can assist the regulator to attract, retain and train skilled regulatory staff, and will also assist in the transfer of knowledge and experience between regulators of different industries. This will contribute to ensuring that regulation in each industry is undertaken in a way that is consistent with, and reflects the lessons learned in, regulation of other industries. Experience suggests that an independent economic regulator, charged with specific legislative responsibilities and objectives, is more likely to challenge businesses' efficiency and proposed expenditure plans. Independent economic regulators also have the necessary skills and experience to

utilise measures to provide incentives for regulated businesses to seek out further efficiency improvements over the duration of the regulatory period.

The consolidation of regulatory and industry experience is relevant to the ERA. The ERA is currently responsible, among other things, for regulating the monopoly aspects of the gas, electricity and rail industries, and for licensing providers of gas, electricity and water services. The ERA also has a range of responsibilities in relation to the retailing of gas and the surveillance of the wholesale electricity market in Western Australia. In undertaking its existing functions, the ERA has built up regulatory and economic experience that can be applied to the review of retail electricity tariffs.

Making the ERA responsible for future tariff regulation is consistent with the majority of views expressed in response to the OOE's Issues Paper.

Making the ERA responsible for future tariff regulation is also consistent with the approach in most other jurisdictions:

- In New South Wales, IPART is responsible for electricity tariff regulation, with Terms of Reference from the Minister for Energy.
- In South Australia, ESCOSA is empowered to make price determinations in regard to electricity tariffs, subject to the requirements of *Electricity Industry Act 1996.*
- In Tasmania, OTTER is responsible for electricity tariff regulation, although the energy cost component of electricity tariffs is set out in Price Control Regulations following a review process undertaken by the Department of Treasury and Finance in conjunction with OTTER.
- In the ACT, the ICRC is responsible for electricity tariff regulation, with Terms of Reference issued by the ACT Government.
- In Queensland, the QCA is responsible for determining the BRCI, subject to the requirements of *Electricity Industry Act 1994.*

The clear exception is Victoria. In Victoria, regulated tariffs are agreed between the Department of Infrastructure and the businesses. We note, however, that the AEMC has recently recommended that energy retail price regulation be removed in Victoria,[54] and that the Victorian Government has recently introduced the *Energy Legislation Amendment (Retail Competition and Other Matters) Bill 2008* that provides for retail price regulation to be replaced with a price monitoring regime.

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[54] AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria*, Second Final Report, 29 February 2008.

Appendix 1 – Terms of Reference

The review and assessment of the electricity tariff arrangements is to consider:

(a) A review of the existing tariff arrangements, including an examination of:

- the current and expected future cost structure across each of the current tariffs; and
- details of the consumption profile under each tariff, including whether consumption is evenly distributed within each customer class under each tariff.

This should enable an assessment of:

- the appropriateness of each tariff;
- whether there is sufficient margin for competition in each tariff; and
- whether there is opportunity for consolidation or restructuring of the tariffs.

(b) The appropriate structure and level of tariffs, including consideration of:

- applicability of tariffs to different customer classes;
- cost reflectivity of the tariffs;
- the level of tariffs necessary to promote competition for each customer class;
- the merits of the introduction of time-of-use ("TOU") tariffs and/or critical peak pricing, including consideration of:
  - the most appropriate tariff structure and tariff levels required to promote an increased focus on overall and peak-load management of electricity demand;
  - the roll-out of smart meters (see item 3 below); and
  - any equity considerations for the introduction of such tariffs on consumers; and
- cost impacts associated with the implementation of greenhouse gas reduction initiatives.

(c) Incentives for electricity consumers to negotiate alternative supply arrangements.

(d) Timing for any necessary changes to the tariff structure, including the transition process for amendment of the tariffs, and accounting for the Government's commitment to ensure that existing tariffs for residential and small business customers remain unchanged until at least 2009.

(e) The appropriate index mechanism for annual tariff adjustments, and the criteria to be used in conducting regular reviews of the tariff adjustment mechanism.

(f) Any other tariff-related issues that are identified, as appropriate.

Appendix 2 – Abbreviations

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CCGT	Combined cycle gas turbine
EBIT	Earnings before interest and taxation
EBITDA	Earnings before interest, taxation, depreciation and amortisation
ESC	Essential Services Commission
ESCOSA	Essential Services Commission of South Australia
ERA	Economic Regulation Authority
FRC	Full retail competition
IMO	Independent Market Operator
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
LRMC	Long run marginal cost
NEM	National electricity market
NEMMCo	National Electricity Market Management Company
OCGT	Open cycle gas turbine
OOE	Office of Energy
ORG	Office of the Regulator General
OTTER	Office of the Tasmanian Energy Regulator
QCA	Queensland Competition Authority
SAIIR	South Australian Independent Industry Regulator
SME	Small and medium enterprises
STEM	Short term energy market

SWIN	South west interconnected network
SWIS	South west interconnected system
TEC	Tariff equalisation contribution
TEF	Tariff equalisation fund
WACC	Weighted average cost of capital
WEM	Wholesale electricity market

Appendix 3 – References

CRA, *Electricity and Gas Standing Offers and Deemed Contracts (2003)*, Submitted to the Department of Natural Resources and Environment, December 2002.

CRA, *Electricity and Gas Standing Offers and Deemed Contracts (2004-2007)*, Submitted to the Department of Infrastructure, December 2003.

CRA International, *Impact of Prices and Profit Margins on Energy Retail Competition in Victoria*, Final Report, November 2007.

ESCOSA, *2004 Electricity Standing Contract Price*, Final Report, December 2003.

ESCOSA, *Inquiry into Retail Electricity Price Path*, Final Report, March 2005.

ESCOSA, *2007 Review of Retail Electricity Price Path*, Draft Inquiry Report and Draft Price Determination, August 2007.

ESCOSA, *2007 Review of Retail Electricity Price Path*, Final Inquiry Report and Price Determination, November 2007.

ICRC, *Investigation into Retail Prices for Non-Contestable Electricity Customers in the ACT*, Final Determination, May 2003.

ICRC, *Retail Prices for Non-contestable Electricity Customers*, Final Decision and Price Direction, June 2007.

IPART, *Regulated Retail Prices for Electricity to 2004*, Final Report, December 2000.

IPART, *Mid-term Review of Regulated Retail Prices for Electricity to 2004*, June 2002.

IPART, *NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07*, Final Report and Determination, June 2004.

IPART, *Promoting retail competition and investment in the NSW electricity industry, Regulated electricity retail tariffs and charges for small customers 2007 to 2010*, Electricity – Final Report and Final Determination, June 2007.

ORG, *Special Investigation – Electricity Retailers' Proposed Price Increases*, Final Report, December 2001.

OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania*, Final Report and Proposed Maximum Prices, September 2003.

OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania*, Final Report and Proposed Maximum Prices, September 2007.

SAIIR, *Electricity Retail Price Justification, Final Report, September 2002 and ESCOSA*, Inquiry into Electricity Standing Contract Prices, Final Report and Determination, October 2002.

Appendix 4 – Response to specific issues raised in submissions to the draft recommendations report

A number of stakeholders have made public submissions to the OOE on the OOE's draft recommendations report and Frontier Economics' draft recommendations report. This Appendix sets out Frontier Economics' response to submissions on specific issues related to Frontier Economics' draft recommendations report.

VESTING CONTRACT AND VERVE SUSTAINABLE ENERGY PRICE

In its public submission to the OOE, Synergy comments that it considers that Frontier Economics' approach does not support the magnitude of the risk exposure that Synergy faces in the market, especially in relation to displacement under the Vesting Contract.

In particular, Synergy considers that the retail margins proposed by Frontier Economics for non-contestable customers are too low to compensate for the wholesale risk that Synergy faces for generation procured via displacement from the Vesting Contract. Synergy notes that in Western Australia there is no clear mechanism to allow the pass through to customers of purchase costs under the displacement mechanism. Synergy notes that in the early days of the UK pool, the UK regulator reviewed wholesale contracts that retailers signed and generally allowed the prices within these contracts to be passed through to customers. As a result, the retailers did not face the risk that the wholesale contract would be out of the money.

There is certainly an important link between risk and the appropriate retail margin. It is this link that is reflected in the retail margins recommended in Frontier Economics' draft recommendations report. The recommended margin for non-contestable customers is lower than the recommended margin for contestable customers because the Vesting Contract reduces the energy purchase risk to which Synergy is exposed for non-contestable customers.

Certainly, as the Vesting Contract is displaced, the extent to which Synergy faces energy purchase risk for non-contestable customers is likely to change. For this reason, as the Vesting Contract is displaced, there is likely to be reason to increase the retail margin for non-contestable customers in order to reflect the increase in energy purchase risk.

Frontier Economics considered the impact of the displacement mechanism when recommending the retail margin for non-contestable customers. Frontier Economics noted in its draft recommendations report that current forecasts indicated that the extent to which non-contestable customers are covered by the Vesting Contract would fall from around 90 per cent in 2008/09 to close to 70 per cent in 2011/12. In other words, Synergy's non-contestable customers would

remain largely covered by the Vesting Contract throughout the forecast period. Partly as a result of this, Frontier Economics considered that a lower retail margin was appropriate for non-contestable customers throughout the forecast period. Frontier Economics notes, however, that the recommended retail margin of 3 per cent is at the high end of retail margins in other jurisdictions in which retailers are covered by a vesting contract.

In future, as the displacement under the Vesting Contract continues, it will be important to revisit the appropriate retail margin for non-contestable customers. However, it is important to recognise that the appropriate retail margin will depend on the way that tariffs are regulated. In Frontier Economics' draft recommendations report, the wholesale cost of energy purchased through the displacement mechanism is based on forecasts of the long-run marginal cost (LRMC) of electricity. There is a risk that future changes in costs will not reflect those that are assumed in forecasting LRMC, so that actual energy purchase costs diverge from forecast LRMC. It would appear that Synergy's proposal is for the wholesale cost of energy purchased through the displacement mechanism to be based on the actual prices of Synergy's wholesale contracts. This can be thought of as being analogous to a regulatory mechanism in which any differences between forecast energy purchase costs and actual energy costs are passed-through to customers. This would substantially mitigate against the increase in risk that Synergy would face as a result of the displacement of the Vesting Contract, with implications for the appropriate retail margin.

IMO COSTS

In its public submission to the OOE, Synergy comments that it is unclear whether Frontier Economics' estimate of market fees includes excess capacity payments.

Frontier Economics' estimate of market fees does not include excess capacity payments. Nor are excess capacity payments *explicitly* captured in Frontier Economics' estimate of wholesale costs.

The reason for this relates to the approach adopted by Frontier Economics to estimate the wholesale cost. Frontier Economics' estimates of wholesale costs are based on a cost-based approach rather than a market-based approach. Under a cost-based approach, efficient wholesale costs are assessed on the basis of the resource costs involved in the supply of electricity. Under a market-based approach, efficient wholesale costs are assessed on the basis of market prices. As discussed in Frontier Economics' draft recommendations report, a cost-based approach and a market-based approach will tend to provide similar estimates of wholesale costs over the long run. In the short term, however, the two will vary. In particular, a market-based approach will provide estimates of wholesale costs that are more dependent on market conditions such as scarcity and competition.

Frontier Economics considers that excess capacity payments are best thought of as one component of the total price paid for electricity in the market and, therefore, one component of the wholesale cost under a market-based approach. To the extent that there is excess capacity in the short term, one effect of this

would be to lead to positive excess capacity payments. However, excess capacity in the short-term would also be expected to affect other market-based prices, including the price of capacity and energy under bilateral contracts and, potentially, prices in the STEM. In addition, Frontier Economics notes that the administered Capacity Price in the WEM is decreased to the extent that there is excess capacity in the market. The result is that the total cost of capacity credits is the same whether or not there is excess capacity in the market.

As a price signal, it is unclear why excess capacity payments should be considered part of the wholesale cost under a cost-based approach. First, the LRMC of energy incorporates the costs of building and operating an efficient mix of generation plant to meet a given load. In effect, the capacity costs associated with this mix of generation plant are incorporated into LRMC. Adding additional payments for capacity will simply result in an estimate of the cost of a mix of generation plant that is inefficient in the long-run. Second, even if it were considered appropriate to adjust LRMC for short-term market conditions such as scarcity and competition, incorporating excess capacity payments into LRMC would not be the appropriate way to do this. The reason is that prices in the Wholesale Electricity Market are related to each other, and incorporating a single price signal into an estimate of resource costs will fail to reflect these relationships.

GREEN ENERGY

In its public submission to the OOE, Synergy comments that Frontier Economics' estimates of REC prices do not reflect market reality in Western Australia.

As noted in Frontier Economics' draft recommendations report, Frontier Economics' approach to estimating REC prices is to estimate a national price for RECs. Since MRET is national in scope, and RECs are tradeable in a national market, Frontier Economics' view is that REC prices will continue to be determined on a national basis. If renewable energy is more expensive relative to black energy (or black energy plus carbon when a national ETS is in place) in Western Australia than is the case in the rest of Australia, then retailers in Western Australia would be better off buying RECs in the national market. Or, to put this another way, if renewable generators in Western Australia attempted to charge a higher price for RECs than renewable generators in other parts of Australia, retailers would be better off not buying from these renewable generators in Western Australia.

In addition, Frontier Economics notes that there is an important link between REC prices and carbon prices. With the introduction of a national ETS and a price for carbon, the cost of black energy will, in effect, increase. This will have an effect on the REC price, with a lower REC price required to bridge the gap between the cost of renewable energy and the cost of non-renewable energy when non-renewable energy faces a carbon price. The MRET scheme includes a leeway of 10 per cent of the obligation, which can be carried over for up to 3 years. This acts as a form of borrowing and, at the margin, can cause the price effect of the introduction of an ETS to be brought forward. Both the price effect

of the introduction of an ETS and the impact that the 10 per cent leeway can have on the REC price are captured in Frontier Economics' modelling.

In any case, as noted in Frontier Economics' draft recommendations report, there remains significant uncertainty about the operation of both MRET and a national ETS. Frontier Economics' modelling has made assumptions about how these schemes will operate, based on the best available information. Changes in these assumptions will result in changes in the forecast costs of complying with both MRET and a national ETS. As noted in the OOE's draft recommendations report, the purpose of Frontier Economics' modelling was to provide an indication of future costs of complying with greenhouse schemes.

NETWORK COSTS

In its public submission to the OOE, Synergy comments that it is unclear whether network cost assumptions adequately reflect the effects of future environmental obligations, specifically MRET, on network investment.

In its public submission to the OOE, Western Power comments that network tariff increases will be greater than previously suggested by Western Power.

As noted in Frontier Economics' draft recommendations report, network tariffs in Western Australia are regulated by the Economic Regulation Authority. As a result, considering the appropriate level of network tariffs is beyond the scope of the Review. As noted in the OOE's draft recommendations report, actual network tariffs will be a pass-through charge.

Frontier Economics did incorporate increases in network tariffs into a total cost stack in order to estimate the impact on customers of the R component of retail tariffs set out in Frontier Economics' draft recommendations report. Western Power provided forecasts of increases in network tariffs and those forecasts were adopted by Frontier Economics in estimating customer impacts. However, those forecast network tariff increases did not have any impact on the R component of the retail tariffs recommended by Frontier Economics.

LOSS FACTORS

In its public submission to the OOE, Landfill Gas and Power raised the issue of loss factors, and how these are incorporated into the retail tariffs recommended by Frontier Economics.

Frontier Economics' forecasts of efficient generation costs are estimated at the generator level. These costs need to be escalated to take account of network losses associated with supplying customers. In determining the tariffs recommended in Section 10 of Frontier Economics' draft recommendations report, Frontier Economics has escalated wholesale costs for each retail tariff by an estimate of the network losses – including transmission losses and distribution losses – for that retail tariff. Network losses are reported on a network tariff basis rather than a retail tariff basis, so for those retail tariffs for which customers are on a number of different network tariffs, network losses were estimated as the energy weighted average of the network losses for the relevant network tariffs.

RETAIL OPERATING COSTS

In its public submission to the OOE, Synergy comments that Frontier Economics' estimate of retail operating cost for contestable customers do not include customer acquisition or retention costs.

As discussed in Frontier Economics' draft recommendations report, Frontier Economics considers that retail operating costs for contestable customers are higher than retail operating costs for non-contestable customers, including as a result of additional marketing and account management costs. Frontier Economics considers that these additional marketing and account management costs incorporate customer acquisition and retention costs.

MARGIN

In its public submission to the OOE, Synergy comments that it considers that retail margins should not be averaged, but should be calculated for each tariff classification to reflect the different cost and risk attributed to each regulated tariff customer class.

In principle, Synergy's suggestion is a sensible one. Particularly to the extent that there are identifiably different risks associated with supplying particular groups of customers, it makes sense for the retail margins for these customers to be different. In practice, though, there are a number of difficulties with Synergy's suggestion.

First, it is unclear how the risk associated with supplying customers differs across each of the regulated tariffs. Certainly, to the extent that retail contestability and the Vesting Contract result in different energy purchase risk or volume risk across customer groups, Frontier Economics has recommended different retail margins. However, it is unclear what would account for the different levels of risk associated with supplying contestable customers on different tariffs or non-contestable customers on different tariffs. Synergy has not set out the reasons it considers that risks – and therefore the margin – should differ between particular tariffs.

Second, there are significant practical difficulties in estimating a retail margin for particular narrow groupings of customers. The only way to robustly quantify an appropriate retail margin for each regulated tariff would be to model the appropriate retail margin. However, to do this for each regulated tariff would require estimates of the costs and assets associated with supplying customers on each regulated tariff. This, in turn, would require the allocation of costs and assets to particular regulated tariffs. Necessarily, any such allocation would require a number of relatively arbitrary decisions regarding the allocation of costs and assets that are common to the retail business as a whole. Since the estimated retail margins under this approach would be sensitive to these allocation decisions, Frontier Economics considers that there is little to be gained from attempting to estimate retail margins on a narrower basis.

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