Inquiry into the Funding Arrangements of Horizon Power

Final Report

18 March 2011

Economic Regulation Authority
WESTERN AUSTRALIA

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The inquiry into the funding arrangements of Horizon Power was given to the Authority, by the Treasurer, on 17 May 2010. Its purpose is to consider the level of Horizon Power's efficient operating and capital expenditure and determine cost reflective tariffs for each year of the review period (2009/10 to 2013/14).

Horizon Power's services and history

Horizon Power is the regional electricity service provider for the majority of Western Australia, excluding the South West and Kalgoorlie. This is an area of 2.3 million square kilometres stretching from Kununurra in the East Kimberley, through the Mid West towns to Esperance in the South. Horizon Power is a vertically integrated company responsible for generating, transmitting, distributing and retailing electricity services across its supply area. Population and hence demand for electricity is concentrated in a few key areas, the North West Interconnected System (**NWIS**) (50 per cent of electricity sent out) and the main towns of Kununurra, Broome, Carnarvon and Esperance (33 per cent of electricity sent out). The remainder of Horizon Power's supply area is characterised by small, isolated towns served by local generation and islanded distribution systems.

Upon disaggregation from the former Western Power Corporation, Horizon Power inherited an ageing asset base and support systems better suited to a larger, centrally managed business model. Consequently, over the last four years, Horizon Power has undertaken asset management planning and renegotiation of service level agreements for information technology, metering and customer service functions. Horizon Power has 33 discrete distribution systems in addition to the NWIS, which are subject to harsh environmental conditions: cyclones in the north, storms in the south and dry hot conditions in the interior. Furthermore, Horizon Power's staff are often required to travel long distances to correct faults and maintain systems, which impacts upon repair times and service performance. Horizon Power's customer base ranges from remote aboriginal communities such as Ardyaloon and Bidyadanga in the West Kimberley to large commercial mining and resource customers in the NWIS.

The Tariff Equalisation Contribution (TEC)

Given these environmental and operational conditions and the Government's current policy to charge uniform electricity retail tariffs[1] across the entire State, the cost to supply customers across much of Horizon Power's area is greater than the revenue collected from its customers. Therefore, Horizon Power receives subsidies in the form of Customer Service Obligation (**CSO**) payments, funded through general taxation, and the Tariff Equalisation Contribution (**TEC**), which is funded from the network charges to Western Power's wholesale distribution customers. At the current gazetted levels ($122.1m in 2009/10, $175.7m in 2010/11 and $181.2m in 2011/12), the growth in the TEC is increasing Western Power's network distribution charges by CPI plus 15.7 per cent (over three instalments, March 2010, July 2010 and July 2011).[2]

[1] Uniform tariffs do not apply to large commercial customers with usage above 4.38 GWh, these customers pay commercial tariff rates.

[2] ERA Media release (4 December 2009), ERA releases final decision on Western Power's revisions

The Authority's approach to the inquiry

Across the majority of its area of supply, Horizon Power provides an essential service and does not charge cost reflective tariffs. This inquiry into the funding arrangements of Horizon Power seeks to simulate the beneficial aspects of a competitive market by:

- determining Horizon Power's efficient cost of supplying electricity for a given level of service delivery; and
- ensuring a benchmark rate of return on the appropriate level of investment in capital assets.

Such an approach encourages increased efficiency in electricity service provision, the prudent use of public funds and minimises the subsidy paid by Western Power's distribution network users.

In carrying out this inquiry, the Authority has adopted the following approach.

- The Authority first reviewed Horizon Power's service levels. These standards concern power quality and reliability and customer service. The review involved considering the current service standards with which Horizon Power has to comply and the service standards against which it reports to the Authority.
- The Authority then applied the "building block" approach to determine Horizon Power's efficient costs of delivering its services to the required standards. This involved separately calculating efficient operating costs, depreciation and a return on the appropriate regulatory asset base. These elements were then summed to determine Horizon Power's efficient cost of service provision (or cost reflective revenue requirement).
- In determining the efficient levels of operating and capital expenditure the Authority sought advice from technical consultants, Parsons Brinckerhoff Australia Pty Ltd (**PB**).[3]
- The data collection and financial modelling exercise resulted in the calculation of the costs of service, analysed by functional cost driver (i.e. generation, transmission, distribution, retail or overhead), for each town, the NWIS and for Horizon Power as a whole.
- The financial modelling was conducted first using Horizon Power's forecast inputs and then using the Authority's recommended efficient operating and capital expenditure levels, asset valuation and return on capital.
- An average cost reflective tariff was calculated for each town, the NWIS and for Horizon Power as a whole.
- Horizon Power's tariff revenue was deducted from the efficient cost of service to leave a balancing revenue item to be met through CSO and TEC funding.
- Finally, the Authority compiled a set of statutory accounts for Horizon Power to ensure that the recommended variations in the costs of service provide for Horizon Power to remain financially sound, assuming Horizon Power operates in accordance with the Authority's efficient level of costs.

[3] This report is available on the Authority's website www.erawa.com.au

Price escalation factors

One issue of difference between the Authority and Horizon Power is in the use of price escalation factors in estimating costs. In its forecasts of operating expenditure, Horizon Power has used several alternative price escalators to the Consumer Price Index (**CPI**)[4] as it is of the view that CPI does not reflect the underlying cost inflation it faces. This is particularly relevant in the North West of the State, where competition for materials and labour can drive prices higher than in other parts of the State. The Authority recognises that regional prices have probably risen at a higher rate than CPI in the past although it is uncertain if this trend will continue, especially as Horizon Power's preferred inflator has fallen since June 2008.

In the absence of a completely suitable indicator, the Authority accepts Horizon Power's position that the BCI[5] is the most suitable indicator to use. Although, historically, BCI is shown to be a volatile index an extrapolation of past trends is probably still the best method to use for forecasting the BCI. The Authority considers that growth in the BCI prior to 1990 was due to growth in all prices in the Australian economy which is unlikely to be repeated. Instead, the Authority has calculated that the average annual growth of BCI from 1990 to 2010 is three per cent. The Authority considers that this value could be an appropriate escalator to use for Horizon Power.

Therefore, with the exception of any cost inflation fixed by contractual terms, the Authority has applied a three per cent escalation to what it considers is Horizon Power's efficient operating cost profile for this inquiry.

The forecast capital costs modelled in the inquiry include a single 20 per cent uplift above the equivalent Perth cost to reflect the increased capital costs faced by Horizon Power in the regions.

Operating costs

Horizon Power has forecast average operating costs of $329.3m (real at 30/6/2009) per annum over the review period compared to an historical annual operating cost average of $237.7m (real at 30/6/2009). This represents an increase of 28 per cent in annual average operating cost between the two periods. These operating costs are predominantly driven by the contractual costs of purchasing electricity from Independent Power Producers (88 per cent of the electricity sent out in 2009/10). As a consequence, generation operating costs are largely non-controllable in the short-term.

The Authority has therefore concentrated on controllable operating costs (on average $116.8m per annum, real at 30/6/2009) in seeking potential efficiency gains in operating costs. This compares against a historical annual controllable operating cost average of $48m (real at 30/6/2009).

If this real controllable operating cost expenditure is divided by the number of connections supplied, unit operating costs, as forecast by Horizon Power, increase by six per cent over the review period. Of these controllable operating costs, the main drivers are costs deemed as "overheads" by Horizon Power. The high level of overheads partly results from Horizon Power's practice of forecasting at the district and central level and not at the

[4] The weighted average of eight cities CPI

[5] Buildings Construction Index – a Department of Treasury and Finance model for forecasting cost escalation for non-residential buildings (e.g. hospitals, schools, police stations, etc) with input from various business units within the DTF for use by WA public sector agencies

individual town or system level. In the modelling for the inquiry, there was no alternative but to treat costs incurred at the central or district level as overhead.

The Authority recognises that Horizon Power has experienced a period of adjustment and consolidation following disaggregation from Western Power Corporation. However, the Authority considers there is scope for efficiency savings in Horizon Power's controllable operating costs over the review period. To eliminate the effect of any additional costs resulting from growth in demand, the Authority is recommending a compounding efficiency target of one percent per connection per annum be applied to Horizon Power's 2009/10 adjusted controllable operating cost base.[6] This has the effect of reducing Horizon Power's controllable unit operating costs by four per cent (real) over the review period.

In total operating cost terms this is a reduction of $72.6m in total across the five years of the review period and reduces the average annual operating cost from $329.3m to $314.8m (real at 30/6/2009).

Service provision

In reviewing Horizon Power's current service standards, the Authority confirmed that, whilst three towns did not currently meet the required service standards for the average length of interruption to customers, Horizon Power expects all systems to meet the required standards by July 2011.

Any change to Horizon Power's service standards would require a regulatory change and confirmation that customers would be willing to pay for or accept revised service standards. The Authority considers that this is outside the scope of the Terms of Reference for the inquiry and so has concentrated on determining the efficient levels of expenditure required to provide service to the current legislative service standards.

Valuation of the Initial Capital Base

The determination of Horizon Power's cost of service required the valuation of Horizon Power's initial asset base at disaggregation in 2006 and the subsequent increase in this asset base due to new capital additions. Horizon Power proposed an asset valuation of $747.4m (nominal) at 30 June 2009 based on a depreciated replacement cost valuation of its assets.

The Authority did not accept this valuation because it is likely that this values the assets at more than they actually cost and also includes contributed assets that were funded by third parties. It is not generally considered appropriate to provide regulated companies with a return on and of their assets that is greater in present value terms than the amount the regulated companies would have initially paid for the assets. To do otherwise would be to give the regulated companies a windfall gain. In addition, to include contributed assets in Horizon Power's asset base would result in Horizon Power benefiting from a return on and of assets that it did not pay for. While Horizon Power argued that a higher valuation would provide it with income to pay for asset replacement, the Authority did not accept that it is appropriate to have current customers paying for expenditure that occurs in the future. The rate of return provided to Horizon Power allows it to fund those asset replacements at the time the expenditure is incurred.

For the final report, the Authority reviewed its calculation of Horizon Power's ICB and used an inflation-adjusted historical cost to determine an ICB valuation of $388.7m (nominal).

6 The 2009/10 base year operating costs have been adjusted to account for certain items. This is explained in more detail in section 7.7

This compares to a written down historic valuation of $264.1m (nominal) in the draft report.

The higher inflation-adjusted historical cost valuation recognises the inflation and nominal depreciation of each of the assets in Horizon Power's fixed asset register from their commissioning date to 30 June 2009. The Authority is concerned that the asset value is also likely to include assets that were funded by third parties which means the asset value is higher than it otherwise would be. However, it is a value, nevertheless, that results in Horizon Power being a financially sound business.

Capital expenditure

The main driver of the capital expenditure programme over the inquiry period relates to Horizon Power's strategy to build, own and operate its own power stations in Marble Bar, Nullagine, Carnarvon and South Hedland.

The Authority has reviewed, and accepted, Horizon Power's demand forecasts which drive the need for additional generation capacity across the supply area. However, the Authority is concerned that, based on the information available, the decision to bring some generation capacity in-house is not the optimal business model for Horizon Power to adopt. Consequently, in addition to specific project-related capital expenditure reductions, the Authority also proposes to exclude, from the determination of efficient costs, any outturn costs from these generation projects over and above the budgeted amounts. This ensures that any cost overruns for the generation projects are borne by Horizon Power and not passed on to those who are subsidising Horizon Power's operations.

Expenditure on new assets was reviewed by PB in its technical review and PB recommended that expenditure on several projects be removed from the Authority's efficient capital expenditure profile. In its submission on the draft report, Horizon Power argued that all of the exclusions recommended by PB be reinstated. The Authority has since reviewed five business cases submitted by Horizon Power regarding forecast capital expenditure and has excluded certain project expenditure on the basis of the information reviewed.

The combined effect of the Authority's recommendations to specific projects and to generation capital expenditure generally is to reduce Horizon Power's proposed capital expenditure from $841.6m (real at 30/6/2009) over the inquiry period to $798.2m, a reduction of $43.4m (real at 30/6/2009).

Return on capital

In determining a benchmark return on capital, the Authority reviewed the underlying parameters that Horizon Power proposed and where appropriate amended these to reflect current market conditions and accepted regulatory practice. This has resulted in a real pre-tax return on capital of 7.23 per cent.

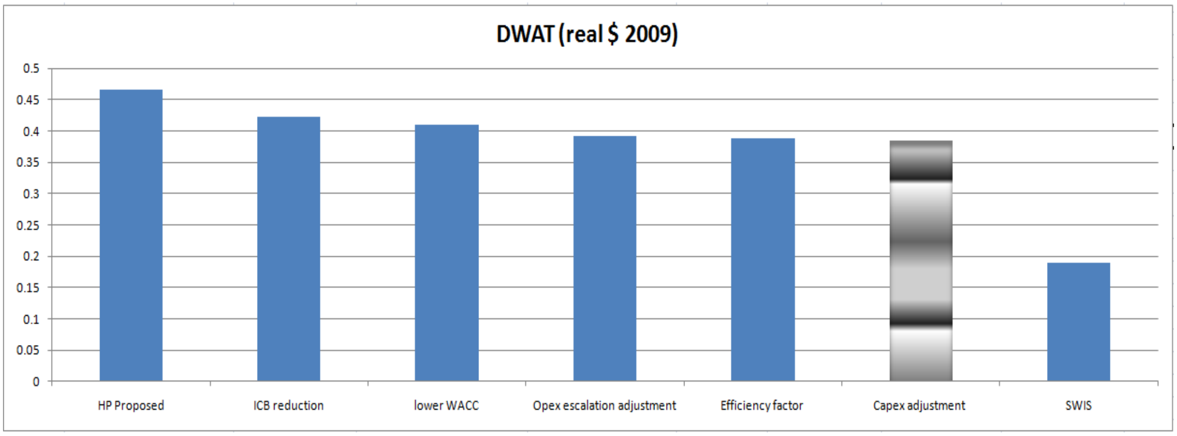
The Authority notes that Horizon Power, as a Government Trading Enterprise, has access to debt funding at favourable rates from Western Australian Treasury Corporation. If Horizon Power's actual cost of debt is used in the return on capital calculation rather than the benchmark rate of return, the real pre-tax return reduces to 5.77 per cent. It is this alternative rate of return that the Authority has used to derive TEC values over the review period because customers paying for the subsidy should only bear the actual costs incurred by Horizon Power.

Cost-reflective tariffs

The combination of the above elements determines the efficient cost of service for each town for each year of the review period and for Horizon Power as a whole. The Authority has then translated these costs of service into an average cost-reflective tariff for each town and for Horizon Power as a whole.[7]

The effect of the Authority's adjustments to the inputs forecast by Horizon Power on the average cost reflective tariff for Horizon Power as a whole is shown in Figure 1.1 below.

Figure 1.1 The incremental effect of Authority's proposed reductions on the discounted weighted average tariff for Horizon Power



Source: ERA analysis

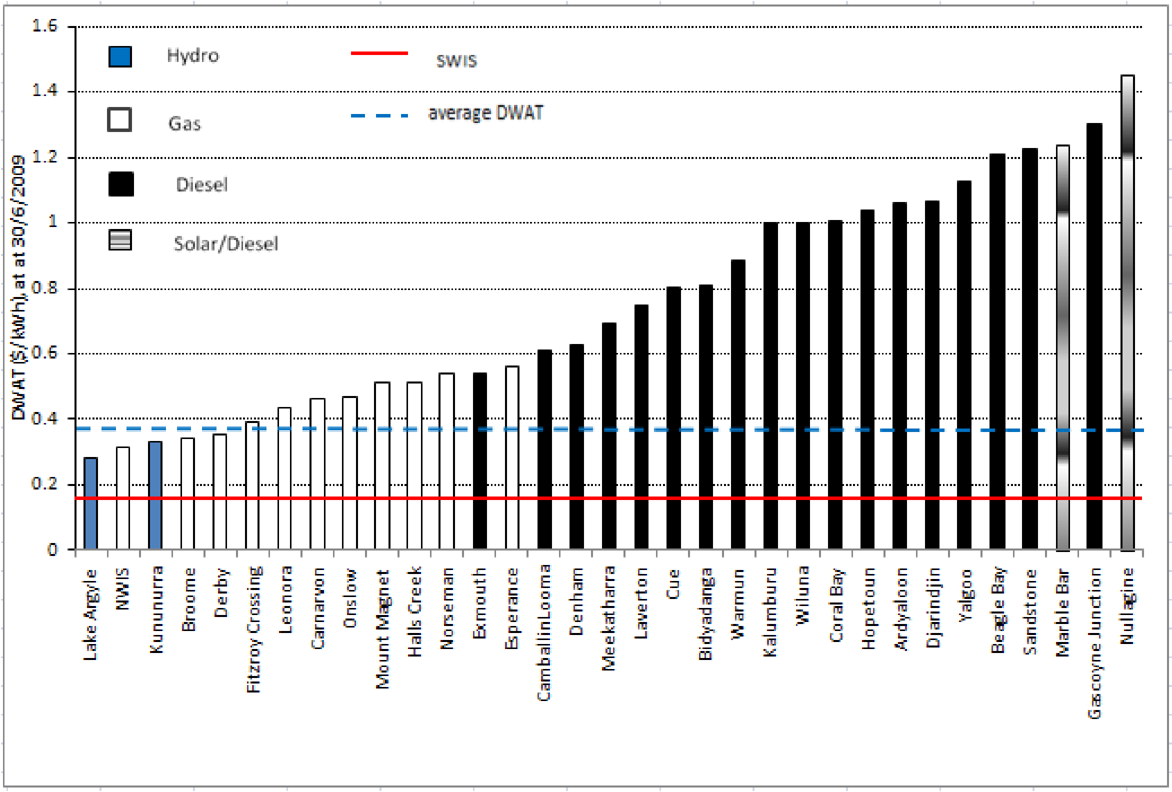
Overall, the Authority has reduced average cost-reflective tariffs by $0.08 per kWh, down from $0.47 per kWh to $0.38 per kWh. The comparative figure for the SWIS is $0.19 per kWh.

The average tariff reduction mainly results from reducing Horizon Power's asset valuation, applying a lower return on capital, applying a lower escalation factor and efficiency target to Horizon Power's level of efficient operating costs and reducing Horizon Power's forecast capital expenditure to efficient levels.

On an individual town level the cost-reflective tariffs range from $0.28 per kWh for Lake Argyle in East Kimberley to $1.46 per kWh for Nullagine in the Pilbara. The NWIS is $0.32 per kWh and the consolidated tariff for Horizon Power is $0.38 per kWh (broken blue line in Figure 1.2 below). The equivalent figure for the SWIS is $0.19 per kWh (solid red line in Figure 1.2 below). The difference in tariff levels is largely due to the type of fuel used to generate electricity, the capacity of the generator and the distance between the town and its main fuel supply.

7 These tariffs are calculated using the real pre tax benchmark return on capital.

Figure 1.2 Simple cost reflective tariffs for each town and the NWIS compared to the equivalent tariff for the SWIS ($ per kWh)



Source: ERA analysis

- Hydro is the least expensive source (as evidenced by Lake Argyle and Kununurra at the low end of the tariff range), followed by gas (used in towns such as Broome, Derby and Esperance), then diesel (a fairly wide range from Exmouth to Gascoyne Junction), then solar and diesel combined (Marble Bar and Nullagine).
- The larger the generation capacity, the lower the cost to supply (the NWIS has the largest installed capacity and a low tariff compared to towns such as Gascoyne Junction, Yalgoo and Ardyaloon, which have installed capacity at less than 1MW).
- Also, the greater the distance of the town from support infrastructure, the higher the diesel transport costs (as evidenced by the higher costs of supplying more remote towns such as Ardyaloon, Djarindjin and Beagle Bay in the West Kimberley).

All of the cost reflective tariffs generated are above the equivalent figure for the SWIS, which indicates that all of Horizon Power's towns and systems require a subsidy.

Impact on the TEC

The Authority's preferred position is that the TEC is funded by a CSO payment paid directly to Horizon Power. The benefits of this are:

- lower network tariffs in the SWIS;
- removal of price distortion in the competitive markets in the SWIS;

- an earlier timeframe to achieve full retail contestability in the SWIS;[8]
- greater transparency around the overall level of the subsidy for Horizon Power; and
- consistency with how other utilities are subsidised.

The Authority considers that these benefits to customers and the electricity market outweigh the retention of the TEC in its current form.

However, if the Government continues to choose to fund the TEC via network charges in the SWIS then the Authority considers that the TEC should be calculated on the basis of the actual costs incurred by Horizon Power. That is, it should be calculated using the rate of return based on Horizon Power's actual cost of debt.

The impact of the Authority's derived TEC values compared to current gazetted TEC values shows a net present value saving of $34.6m on the current gazetted TEC levels for those three years (all prices are nominal).

Table 1.1 Comparison of TEC values ($m nominal)

Scenario	2010	2011	2012	2013	2014
Gazetted TEC	122.1	175.7	181.2	n/a	n/a
TEC using benchmark WACC*	127.1	147.2	167.5	188.0	193.3
Reduction on gazetted TEC	*5.0*	*-28.5*	*13.7*	*n/a*	*n/a*
TEC using alternative WACC**	121.3	140.0	156.3	173.7	176.4
Reduction on gazetted TEC	*-0.8*	*-35.7*	*-24.9*	*n/a*	*n/a*

* benchmark WACC assumes market borrowing rates
** alternative WACC assumes Horizon Power's actual cost of borrowing
Source: ERA analysis

If the alternative WACC is used, based on Horizon Power's actual cost of borrowing, the TEC reduces further as shown in Table 1.1 above. This shows an additional net present value saving over the three years of $9.9m (This equates to a total net present value saving of $44.5m between the TEC based on the alternative WACC and the gazetted TEC). Lower TEC payments would be expected to pass through to lower distribution network tariffs for the benefit of Western Power's distribution customers. Any subsequent funding shortfall for Horizon Power as a result of this could be met through an additional Government subsidy funded by all taxpayers, not just electricity customers.

Future regulatory arrangements

The Authority recommends that this inquiry be repeated in three years to ensure a continued path towards efficiency. It is the Authority's experience that as more efficiency reviews are undertaken, confidence in the underlying data quality and regulatory methodology increases, which drives further improvements in performance.

[8] This is on the basis that there would be an earlier timeframe to achieve cost-reflective retail tariffs in the SWIS.

Summary of Recommendations

This section explains and lists the Authority's final recommendations for the inquiry into the funding arrangements of Horizon Power.

Price escalation factors

This recommendation provides for an escalation factor to be applied to Horizon Power's level of efficient operating costs for the review period to recognise the increased labour and material prices Horizon Power faces across some parts of its supply area.

1. **Horizon Power's level of efficient operating costs include an allowance to reflect escalation by an index calculated from historical Building Cost Index data from 1990 to the date of the start of the review period. For this review period, this escalation figure has been calculated at 3 per cent per annum.**

Service provision

This recognises the level of service standards (e.g. power quality and reliability and customer service) that the efficient levels of costs suggested for the review period should deliver.

2. **The service level standards for Horizon Power be retained, unchanged from their existing form, for the review period.**

Valuation of the initial capital base

This recommendation provides a valuation of Horizon Power's asset base at the start of the review period to reflect the value of the assets given their initial purchase cost and age. This asset base is then rolled forward by Horizon Power's efficient net capital expenditure in order to calculate the return on and return of (depreciation) assets which comprise two elements of Horizon Power's efficient cost of service.[9] Calculation of an appropriate initial capital base is important as this helps to ensure that Horizon Power remains financially sound over the review period.

3. **For the purpose of this inquiry, an inflation-adjusted historical cost asset valuation of $388.7m (in real prices as at 30/6/2009) be used for Horizon Power's initial capital base as at 1 July 2009.**

Operating expenditure

The efficient level of operating expenditure is the third element of the cost of service model from which the Authority has determined cost-reflective tariffs for the inquiry. The recommendations relating to operating expenditure refer to the efficient levels of those costs that are controllable and the efficient levels of those costs that are non-controllable in the short-term. One of the recommendations on operating expenditure also notes a significant item that has been excluded as inefficient expenditure. An efficiency target has also been applied to the efficient level of controllable unit costs in 2009/10 to encourage Horizon Power to reduce controllable costs over the review period.

[9] The third element is efficient operating costs.

4. **An efficiency target of one per cent compounded per annum be applied to Horizon Power's adjusted 2009/10 level of controllable unit costs per connection for the duration of the review period.**

5. **The efficient level of Horizon Power's 2009/10 base year adjusted controllable operating costs be $105.2m (real at 30/6/2009).**

6. **Horizon Power's efficient level of non-controllable operating costs for the review period is $1,029.6m (real at 30/6/2009).**

7. **The forecast operating costs incurred as a result of the delay in obtaining funding approval for the South Hedland power station project are considered inefficient and as such should be borne by Horizon Power (or its shareholder). Consequently, for the purpose of determining cost-reflective tariffs for the inquiry, the Authority has removed the $35m (real as at 30/6/2009) in inefficient operating costs from the non-controllable generation operating costs in the NWIS in 2012/13.**

Capital expenditure

This recommendation identifies the level of efficient capital expenditure over the review period. This expenditure, combined with the initial capital base, enables calculation of the return on, and return of, capital expenditure for the inquiry.

8. **Horizon Power's actual and forecast capital expenditure programme be reduced by $43.4m (real at 30/6/2009) from $841.6m (real at 30/6/2009) to the suggested efficient level of $798.2m (real at 30/6/2009) over the review period, as detailed in Table 8.4.**

Return on capital

This recommendation refers to the return on capital investment that is used to calculate the cost of service for Horizon Power from which cost-reflective tariffs are determined. The return on capital, or benchmark WACC, has been calculated using the cost of debt that would be faced by a service provider operating in a competitive market. However, when considering the subsidy, or TEC, the Authority suggests that Horizon Power's actual cost of debt is used in the return on capital, or alternative WACC, in order to minimise the size of the subsidy paid by customers.

9. **A real pre tax benchmark WACC of 7.23 per cent be used for the calculation of cost-reflective tariffs for the review period. This ensures the calculated tariffs reflect the efficient cost of supplying electricity to regional Western Australia assuming a competitive electricity market.**

10. **A real pre tax alternative WACC of 5.77 per cent reflecting Horizon Power's actual cost of debt be used for determining cost of service and hence TEC levels in this inquiry. This ensures that Horizon Power's actual cost of borrowing is reflected in the derived TEC.**

Impact on the TEC

There are two recommendations relating to the TEC. One outlines the Authority's preferred funding source for the TEC, with the associated benefits. The other recommends how the TEC should be calculated if it is to be retained in its current form. If the alternative WACC is used to calculate the TEC then this will result in a shortfall from cost-reflective revenue requirement for Horizon Power. This funding shortfall could be covered by an additional Government subsidy.

11. **The TEC be funded by a CSO paid directly to Horizon Power. This has the benefits of:**
    a. **lower distribution network tariffs in the SWIS;**
    b. **removing price distortion in the competitive markets that exist within the SWIS;**
    c. **an earlier timeframe to achieve full retail contestability in the SWIS;**
    d. **greater transparency around the overall level of subsidy for Horizon Power; and**
    e. **being consistent with how other utilities are subsidised.**
12. **Should the Government continue to subsidise Horizon Power through a TEC payment funded by SWIS network customers, the lower TEC be gazetted. This will provide for the lower TEC to be passed through to lower distribution network tariffs in the SWIS. The shortfall in TEC could be funded through an additional Government subsidy.**

Future regulatory arrangements

This recommendation outlines the Authority’s preference for another inquiry in the future.

13. **A second inquiry into the funding arrangements of Horizon Power be undertaken in three years time to further review Horizon Power’s actual costs and to set new efficiency targets.**

FINAL REPORT

1 Introduction

The Treasurer of Western Australia gave written notice to the Economic Regulation Authority (**Authority**), on 17 May 2010, to undertake an inquiry into the funding arrangements of Horizon Power, pursuant to Section 32(1) of the *Economic Regulation Authority Act 2003* (**Act**)[10] and in accordance with section 129E(1) of the *Electricity Industry Act 2004*. This section of the Electricity Industry Act provides for the Treasurer to seek advice from the Authority prior to making a determination on the level of the Tariff Equalisation Contribution (**TEC**) payable to Horizon Power.

1.1 Terms of Reference

The Terms of Reference for the inquiry are presented in Appendix A. The Terms of Reference require the Authority to consider and develop findings on:

- the cost-reflective retail tariff that would apply in the areas of operation of Horizon Power, for the purpose of determining the efficient expenditure required to supply customers on regulated retail tariffs located in these areas. This will inform the setting of the amount of the Tariff Equalisation Contribution, which will be determined by Government;
- the cost-reflective retail tariffs should be determined for the period 2009/10 to 2013/14;
- a cost-reflective tariff should be determined for each of the retail tariffs currently provided by Horizon Power, being the A2, K2, L2, M2, N2, W2 and Streetlight tariffs (as detailed in the *Energy Operators (Regional Power Corporation) (Charges) By-laws 2006*);
- the Authority is to determine whether the area that Horizon Power operates in should be separated into sub-areas, given the different cost structures of the systems that Horizon Power operates in, for the purpose of determining cost-reflective retail tariffs. If this is the case, the Authority is to:
  - define the sub-areas (minimising the number of sub-areas as much as possible); and
  - determine a different cost-reflective retail tariff (for each tariff class) for each sub-area;
- the Authority is also to consider and incorporate incentives for Horizon Power to develop and implement efficiency measures, such as gain-sharing mechanisms between customers and Horizon Power, in determining cost-reflective retail tariffs if the Authority considers this would minimise costs within the area that Horizon Power operates in;
- the efficiency of Horizon Power's procurement processes; and
- the efficiency of Horizon Power's operating and capital expenditure programmes, including opportunities for alternative arrangements for service delivery in remote regions.

[10] Section 32(1) of the Act provides for the Treasurer to refer to the Authority inquiries on matters relating to regulated industries. This excludes inquiries governed by the operation of the *Gas Pipelines Access (Western Australia) Law* or the Code in force under section 4 of the *Railways (Access) Act 1998*.

The Authority must give consideration to, but will not be limited to, the following costs when determining retail tariffs:

- the efficient generation costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current and committed stock of generation;
- the efficient network costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current network infrastructure;
- the level of efficient retail costs that would be applicable in the area that Horizon Power services (both operating and capital costs);
- the efficient net retail margin that would apply;
- the efficient costs related to the national Mandatory Renewable Energy Target (MRET), including the expanded MRET if applicable; and
- the efficient costs related to the proposed Carbon Pollution Reduction Scheme (CPRS), including the carbon intensity that should be applied in determining CPRS costs that would be incorporated into the cost-reflective retail tariffs.

In undertaking the inquiry, the Authority recognises section 26 of the Act, which requires the Authority to have regard to:

- the need to promote regulatory outcomes that are in the public interest;
- the long term interests of consumers in relation to the price, quality and reliability of goods and services provided in relevant markets;
- the need to encourage investments in relevant markets;
- the legitimate business interests of investors and service providers in relevant markets;
- the need to promote competitive and fair market conduct;
- the need to prevent abuse of monopoly or market power; and
- the need to promote transparent decision making processes that involve public consultation.

In accordance with section 45(1) of the Act, the Authority has acted through the Chairman and members in conducting this inquiry.

1.2 The review process

The recommendations of this inquiry have been informed by the following public consultation process.

- The Authority published an issues paper on 4 June 2010 and invited submissions from industry, government, other stakeholder groups and the general community on the matters in the Terms of Reference. Four submissions were received in response to the issues paper. These submissions and the issues paper are available on the Authority's website, www.erawa.com.au.
- The Authority published a draft report on 16 December 2010 and invited a second round of public consultation. Seventeen submissions were received in response to the draft report. These submissions and the draft report are also available on the Authority's website.

- The Authority considered the submissions received in response to the draft report in drawing its final recommendations for the inquiry.
- The Authority delivered the final report to the Treasurer on 18 March 2011, after which the Treasurer has 28 days to table the report in Parliament.
- The Authority will publish the final report on its website after the Treasurer has made the final report public.

Further information regarding this inquiry can be obtained from:

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The Communications Branch Pty Ltd.
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Mb: 0424 196 771

2 Inquiry Approach

2.1 Review of the aim of the inquiry

The unit cost of supplying electricity to people living in remote areas in Western Australia, outside the South West, is high because of specific variables associated with these regions, such as climatic conditions, transport distances, fuel costs, limited economies of scale and regional factors affecting labour and material costs. The Government's uniform tariff policy however, ensures that all residential and small business customers pay the same electricity tariffs regardless of where they live. Therefore, the electricity tariffs of customers living in remote Western Australia are subsidised by taxpayers and South West electricity network customers.

The inquiry aims to establish Horizon Power's efficient level of costs to supply electricity to regional Western Australia. From this information the Government can determine the Tariff Equalisation Contribution (**TEC**) which is primarily funded from the retail tariffs paid by electricity customers living in the more densely populated areas of the State. The current gazetted TEC figures are given in Table 2.1 below.

Horizon Power also receives additional funds in the form of Community Service Obligation (**CSO**) payments to cover revenue shortfalls. These revenue shortfalls arise from:

- the smoothing of uniform tariff increases up to cost-reflective levels for the South West (tariff adjustment payment);
- providing additional funding to compensate for revenue shortfalls when customers are transferred between different tariff classes (tariff migration);
- providing rebate schemes to groups of customers such as Seniors; and
- supporting selected State funded projects (e.g. power supply to remote communities and Coral Bay).

The CSOs received by Horizon Power over the review period 2009/10 to 2013/14 are also shown in Table 2.1 below.

Table 2.1 Current gazetted TEC values and CSO payments for the review period ($m nominal)

Funding source	2010	2011	2012	2013	2014
Gazetted TEC amount	**122.1**	**175.7**	**181.2**	**n/a**	**n/a**
CSO payments					
Aboriginal and Remote Community Power Supply Project (Stages 1 and 2)	10.9	12.2	12.8	12.6	13.3
Coral Bay electricity supply	2.6	2.5	2.5	2.6	2.8
Pensioner, Senior, Concession rebates	0.6	0.8	1.0	1.1	1.1
Senior air-conditioning rebate	0.2	0.3	0.3	0.4	0.4
Tariff migration	8.8	7.8	7.5	7.7	7.6
Tariff adjustment payment*	13.9	12.6	0	0	0
Total CSO payments	**37.0**	**36.3**	**24.2**	**24.3**	**25.2**
Total combined subsidy	**159.1**	**212.0**	**205.4**	**n/a**	**n/a**

* These are the latest available published figures for this CSO payment however these may change if the Government decides to alter the rate at which electricity tariffs tend toward cost reflective levels.

Source: Government Gazette No. 153, 25 August 2009, p3325 and Government Gazette No. 208, 17 November 2009, p4639 and 2010/11 Budget Paper No. 3, Appendix 8, p237

The combined subsidy, shown in Table 2.1 above, represents approximately 40 per cent of Horizon Power's total income over the three years from 2009/10 to 2011/12.

2.2 Responses to the issues paper

The Authority received four submissions in response to the issues paper published in June 2010, from Griffin Energy, Alinta Energy, the Office of Energy and Horizon Power. Both Griffin Energy and Alinta Energy commented that the TEC was an inappropriate funding mechanism to subsidise service provision outside of the SWIS and should be replaced by a CSO. They suggested that the competitive markets within the SWIS are being distorted with regard to the true cost of supply because of the existence of the TEC within network charges. It is also the Authority's preferred position that the TEC should be replaced by a CSO. Alinta further commented that a subsidy, such as the TEC is:

> "..facilitating an operating environment where Horizon Power chooses service delivery models without due consideration to the most efficient option"

Alinta also welcomed the opportunity for Horizon Power's costs to be reviewed by an external third party so that appropriate efficiency targets could be set and that ultimately:

> "..the need for the TEC is driven by structural cost differences and not inefficient practises."

The Office of Energy's submission was broadly supportive of the approach being taken by the Authority and the proposed methodology to determine cost-reflective tariffs. However, the submission did recognise Horizon Power's specific operating conditions and encouraged the Authority to account for this when developing cost-reflective tariffs. The Office of Energy also suggested that sub-sets of cost-reflective tariffs could be derived to reflect similar operating conditions or cost profiles.

Horizon Power's submission in response to the issues paper requested that the Authority recognise Horizon Power's social and environmental responsibilities, including the provision of essential infrastructure to enhance State and regional development, when looking at efficient levels of expenditure. Horizon Power also requested that the return on capital recognised the increased level of risk it perceives as a result of its exposure to the variability of commodity prices, cost inflation and demand fluctuations. Horizon Power also stated that it considers there is limited scope for further efficiencies other than those it has already identified.

2.3 Public submission on the draft report

Seventeen submissions were received in response to the draft report for the inquiry and between them commented on all of the recommendations proposed in the draft report. All of these submissions are available on the Authority's website.[11] Detailed comments and quotes from the submissions are contained in the sections entitled 'Public Submissions' in the following chapters.

2.4 How Horizon Power operates

Horizon Power supplies electricity to customers living and working within a 2.3 million square kilometre area from Kununurra in the East Kimberley, through the central Gascoyne/Mid West towns to Esperance in the South. Horizon Power's 43,000 electricity connections range from large industrial and resource companies in the Pilbara, to residents and businesses in district towns such as Broome and Esperance and to remote indigenous communities. The distribution of energy supplied and total population is given by town in Table 2.2 below.

Combining together the figures for Karratha and Port Hedland from Table 2.2 gives information for the North West Interconnected System (**NWIS**). This system accounts for just over 50 per cent of electricity supplied by Horizon Power and 36 per cent of connections. The larger district towns of Kununurra, Broome, Carnarvon and Esperance are responsible for a further 33 per cent of electricity supplied and 40 per cent of connections, with the smaller towns and remote communities making up the remainder. This illustrates the concentration of demand in the NWIS and four key towns. The other 29 towns are characterised by relatively low numbers of connections and small, islanded network systems.

[11] Economic Regulation Authority website www.erawa.com.au

Table 2.2 Energy supplied and population by town across Horizon Power's area of supply

District	Town/system	Percent of total electricity supplied by town in 2009/10	Percent of population by town in 2009/10
East Kimberley	Halls Creek	1.1%	1.3%
	Kununurra	6.2%	5.3%
	Lake Argyle	0.0%	0.0%
	Warmun	0.3%	0.3%
West Kimberley	Ardyaloon	0.2%	0.2%
	Beagle Bay	0.2%	0.2%
	Bidyadanga	0.3%	0.3%
	Broome	14.1%	13.0%
	Camballin/Looma	0.3%	0.1%
	Derby	3.4%	5.3%
	Djarindjin	0.2%	0.3%
	Fitzroy Crossing	1.3%	0.9%
East Pilbara	Marble Bar	0.3%	0.3%
	Nullagine	0.1%	0.1%
	Port Hedland	24.1%	17.0%
West Pilbara	Onslow	0.6%	0.9%
	Karratha	26.1%	19.0%
Gascoyne/Mid West	Carnarvon	4.8%	5.4%
	Coral Bay	0.3%	0.0%
	Denham	0.6%	1.8%
	Exmouth	2.6%	2.9%
	Gascoyne Junction	0.1%	0.1%
	Cue	0.2%	0.4%
	Laverton	0.4%	0.7%
	Leonora	1.0%	0.9%
	Meekatharra	0.8%	1.1%
	Menzies	0.1%	0.2%
	Mount Magnet	0.4%	0.6%
	Sandstone	0.1%	0.2%
	Wiluna	0.3%	0.3%
	Yalgoo	0.1%	0.2%
Esperance	Esperance	7.5%	16.5%
	Hopetoun	0.5%	1.8%
	Norseman	0.5%	1.2%

Source: Horizon Power

Horizon Power's operating conditions contrast to those in the South West where customers are relatively more densely populated and supplied with electricity through the South West Interconnected System (**SWIS**).[12]

In its submission in response to the issues paper, Horizon Power explained its adoption of a decentralised business operating model. This translates to six district offices and one administrative office in Bentley managing the generation, transmission and distribution operations in regional towns and remote communities. Horizon Power advised that this enables it to better focus service provision in remote and regional areas whilst also gathering a sufficient mass of services at the district level to deliver cost saving via economies of scale.[13] Horizon Power's retail functions (metering, billing and customer contact) are predominantly dealt with centrally via third party service contracts.

The downside of the decentralised business operating model is that it introduces an additional layer of overheads at the district level, in addition to the traditional, centralised corporate overhead services such as knowledge and technology, financial services, governance, and human resources. The level of overheads is discussed in more detail in section 7 below.

For purposes of transparency and to better reflect how the company actually operates, the assets and operating and capital expenditure costs associated with each district office and the Bentley office have been modelled separately to produce district level and Bentley office costs of service. These district and corporate costs of service have then been allocated back to the appropriate town (by kWh) to give an adjusted cost of service for each town and the NWIS. This method transparently identifies the contribution of overhead costs to each town.[14] This is explained in more detail in section 10. Appendices D, E, F and G show the percentage contribution of each cost function and total overheads to the overall cost of service, for each town, for the NWIS and (in aggregate) for all non-NWIS towns.

In February 2010 and in anticipation of future additional inquiries requiring similar information, Horizon Power has revised its internal procedures and embarked on a more focused approach to reporting costs and revenues at the activity level.

Upon disaggregation from Western Power Corporation (**WPC**), Horizon Power inherited existing Power Purchase Agreements (**PPAs**) with Independent Power Providers (**IPPs**). These contracts emerged following a funding-driven decision by WPC in the late 1990's not to replace its non-compliant[15] power stations but to outsource electricity generation to third parties through a public power procurement process. Long-dated contracts were awarded to IPPs on demonstration of least cost generation.[16]

Overall, this has resulted in Horizon Power purchasing the majority of its electricity via PPAs (88 per cent in 2009/10), which contributes over $1,003.4m (real at 30/6/09), or 60 per cent to its total operating costs over the five year review period. The levels of operating costs and cost escalation associated with these contracts are fixed over the contract period. This unusually high and fixed level of operating costs relative to capital

[12] The SWIS is the largest interconnected electricity transmission and distribution network in Western Australia and stretches from Kalbarri in the north to Kalgoorlie in the east to Albany in the south.

[13] Horizon Power (2010), 'Submission to the ERA issues paper', p8

[14] The use of kWh to allocate overhead may understate the overhead costs for small towns with low demand.

[15] New noise abatement regulations were introduced in the late 1990s resulting in a number of the existing power stations becoming non-compliant.

[16] Horizon Power (2010) – Fact sheet No. 10 – Western Power Legacy Power Purchase Agreements

expenditure has the effect of driving the majority of the company's cost of service as calculated in section 10 below.

As PPAs expire, Horizon Power competitively tenders for new contracts within the NWIS from a panel of four IPPs, which are then compared to the price for Horizon to build, own and operate its own power station. Parsons Brinckerhoff Australia Pty Limited (**PB**) was asked by the Authority to review the efficiency of this competitive tender process as part of the Authority's assessment of efficient costs for this inquiry.

Similarly, retail and customer services, such as customer contact, meter reading and billing, are provided by third parties through Service Level Agreements (SLAs). This is after Horizon Power reviewed the SLAs in place following disaggregation and renegotiated new agreements with alternative providers. For example, meter reading and billing services were initially provided by Western Power, through its Metering Business System (**MBS**). Horizon Power has found this system to be inflexible for meeting its needs, with limited ability for Horizon Power to influence the forward development of MBS. These problems prompted Horizon Power to develop a new tender and contract award for its metering services.[17]

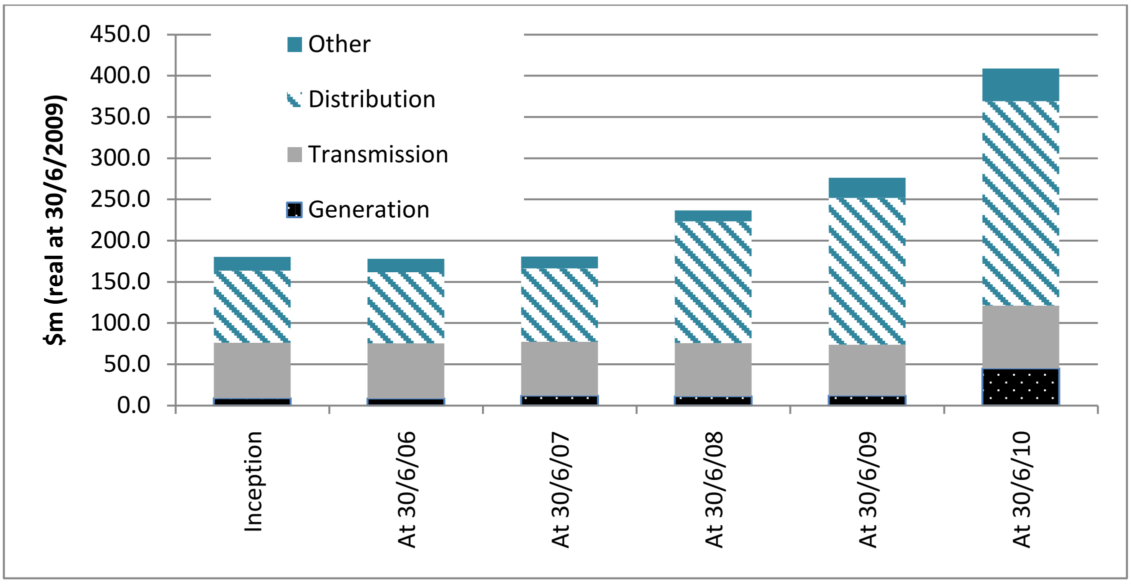
Horizon Power's organisational structure and its new policies concerning which services are provided in-house and which are contracted out has influenced the structure of its capital base.

For the purpose of the inquiry Horizon Power's capital assets[18] are concerned with generation, transmission, distribution and business support, e.g. buildings, furniture and IT systems. Horizon Power owns a minimal amount of assets directly connected with its retail activities. Figure 2.1 below shows the distribution of assets across these different functions and how this distribution has changed historically. From inception the company has gone through a period of establishment and restructuring, this change is shown in the increasing levels of asset growth. Later on, Horizon Power's strategy of bringing some generation in-house is shown through an increase in the value of assets associated with generation.

[17] Horizon Power (2010), Meter Data Management System Replacement Business Case, DMS 3217795, pp15-16

[18] This excludes any assets or cash gifted by third parties, such as the Government, customers or developers.

Figure 2.1 Distribution of assets by function by year ($m real at 30/6/2009)



Source: ERA analysis and Horizon Power spreadsheet 3262769 ERA Fixed Asset Register 20101005vFinal

2.5 Commerciality

Under the *Electricity Corporations Act 2005*, Horizon Power is required to:

> "…supply electricity to consumers and services which improve the efficiency of supply.." [19]

and:

> "…act in accordance with prudent commercial principles and endeavour to make a profit consistent with maximising its long term value." [20]

whilst:

> "…ensuring, as far as is practicable, that the reasonable cost of performing the function does not exceed its revenue from doing so." [21]

Horizon Power has opportunities to operate on a competitive basis, such as in competitively negotiating energy supply contracts with large electricity users or commodity supply and trading. However, across some of the areas in which Horizon Power operates the opportunities to operate competitively are limited and this lack of an opportunity to earn a competitive return on investment deters competitors from entering the market. For example, in all areas Horizon Power operates predominantly as an essential service provider, where the cost of providing essential infrastructure and services exceeds the uniform tariff revenue received for those services. Despite this essential service provision and as evidenced by the above reference to the Electricity Corporations Act, Horizon Power is still legally required to supply electricity as efficiently as possible. The Authority has been mindful of this requirement when setting an efficiency target for Horizon Power's ongoing operating expenditure.

[19] Electricity Corporations Act 2005, Section 50 (d)

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

[21] Electricity Corporations Act 2005, Section 61 (2)(b)

This commerciality requirement has implications for the Horizon Power inquiry. A competitive market normally has desirable outcomes such as downward pressure on prices to reflect the cost of supply and a normal rate of return on the value of assets (after allowing for risk). Where there is a lack of competition, such as across much of Horizon Power's operating area, economic regulation attempts to strengthen the incentive to operate efficiently by imposing pressures similar to those that would be present in a competitive market. For example, when determining cost-reflective tariffs, operating and capital costs are assumed at an 'efficient' level, to simulate the downward pressure on costs that competition would bring.

As Horizon Power is not a regulated utility at the present time, there is no legal requirement for the Authority to set a competitive rate of return for the company. However as part of the inquiry, a benchmark return[22] has been calculated for Horizon Power to simulate an environment were the return on investment decisions is the same as would be present in a competitive market. The benchmark return has been used in the financial modelling for the inquiry to calculate cost-reflective tariffs for Horizon Power. This is to ensure that the cost-reflective tariffs produced are equivalent to those that would exist if Horizon Power operated in a competitive market.

In reality however, Horizon Power has access to debt funding from the State Government, at a favourable rate. Horizon Power can borrow from Western Australia Treasury Corporation at the daily government bond rate plus 20 to 100 basis points depending upon the term of the loan required. Therefore, Horizon Power's actual cost of borrowing is less than the cost of borrowing assumed in the benchmark return on its investment. Because of this discrepancy there is an additional element of cost (representing the difference between the two different costs of borrowing: at the benchmark rate - based on the cost of debt in a commercial market, and the alternative rate - based on Horizon Power's actual cost of debt) within the cost-reflective revenue requirement that is ultimately passed into the TEC. The impact of this additional element of cost upon the TEC is significant. By using the alternative rate of return based on Horizon Power's actual cost of debt compared to the benchmark rate of return, the TEC decreases by $55.4m (nominal) over the review period. This is explained in more detail in section 9 and section 12 below.

2.6 Methodology

Economic regulation generally seeks to:

- determine an efficient level of operating and capital expenditure (to simulate the influence of competitive pressure); and
- value the asset base and then apply an appropriate return on and of this capital (again to reflect a competitive environment and ensure that Horizon Power makes commercially sound investment decisions).

As listed in Appendix A, the Terms of Reference require the Authority to determine cost-reflective tariffs for the review period 2009/10 to 2013/14. To be able to determine cost-reflective tariffs, the Authority firstly determines the efficient cost of supplying electricity, or 'revenue requirement' and then translates this into tariffs. The structure of these cost-reflective tariffs is discussed in more detail in section 11 below. The Terms of Reference also ask the Authority to consider possible gain-sharing mechanisms for Horizon Power; this is covered in section 13 below.

[22] Weighted Average Cost of Capital (WACC) – see Appendix H

The approach taken for this inquiry constructs a 'virtual company' which simulates the business model of a regional power corporation, such as Horizon Power, and estimates efficient levels of costs over the review period, an appropriate asset valuation and return on capital. The operating and capital expenditures are the costs that would be incurred by a prudent service provider acting efficiently and in accordance with good industry practice. The methodology is referred to as the 'building block' approach as the cost components are calculated individually and then summed together to determine the total revenue requirement (or cost of service). This is the typical methodology adopted in most regulated industries including water, gas and electricity.

The revenue requirement is calculated as follows:

Revenue requirement	=	return on capital *plus*
		return of capital (depreciation) *plus*
		efficient operating and maintenance costs
where the return on capital	=	rate of return *multiplied by*
		the regulated asset base

The 'regulated' asset base for this review period is required for the period 1 July 2009 to 30 June 2014. To generate this, the initial capital base at 30 June 2009 is rolled forward by adding efficient new capital expenditure and subtracting asset disposals and depreciation. This is covered in section 6.

The calculation of a benchmark rate of return for Horizon Power, just for the purpose of this inquiry, is outlined in section 9, with a more detailed technical review in Appendix H. The rate of return is determined by calculating the Weighted Average Cost of Capital (**WACC**), a combination of the cost of debt and equity for Horizon Power.

The determination of the efficient levels of operating and capital expenditure, historical and forecast, for the review period are covered in sections 7 and 8 respectively. The Authority engaged technical consultants, Parsons Brinckerhoff Australia Pty Limited (**PB**) to undertake a review of Horizon Power's historical and proposed expenditures and then make recommendations as to the efficient levels of costs for the company. PB's report is published on the Authority's website.[23]

Excluded from actual and forecast total capital expenditure are those projects and activities that are requested by and funded by third parties such as the State or Federal Government, developers and customers. These are termed 'gifted assets' or 'gifted cash' provided to fund capital projects and as such are not added to the asset base and do not earn a return for Horizon Power. Current examples of these projects and their funding sources are shown in Table 2.3 below.

Therefore, only the efficient level of 'owners' capital expenditure is included in the regulatory accounts. This is to ensure Horizon Power only earns a return on the level of efficient expenditure it has funded.

[23] Economic Regulation Authority website is www.erawa.com.au

Table 2.3 Examples of externally funded capital projects ($m real at 30/6/2009)

Project/activity	Funding source	Total project value $m (project period)
Pilbara Underground Power Programme (PUPP)	75:25 - State Government (Royalties for Regions) and Local Regional Councils	100.4 (2010/11 to 2012/13)
Customer initiated projects	100 per cent fully funded from developer and customer contributions	36.6 (2010/11 to 2013/14)
Aboriginal Remote Community Power Supply Programme (ARCPSP)	50:50 – State and Federal Governments	20.3 (2010/11 to 2011/12)

Source: ERA analysis and Horizon Power spreadsheet Capex 020910

When gifted assets, or the assets constructed from gifted cash, reach the end of their economic life they will require replacement. The regulatory model assumes that, at this point, assets will be replaced at their current cost if the replacement of these assets would be undertaken by a prudent and efficient electricity service provider. In this situation, the funding for the replacement of these assets would be provided through whatever funding model was applicable to the electricity service provider at the time.

A similar situation exists for Horizon Power. When its gifted assets are due to be replaced, the approach should be to:

- firstly, determine the regulatory requirement for the replacement of the assets against various operational altrenatives; and
- secondly, assess the efficiency of the expenditure required to fund the replacement.

If a sufficiently strong regulatory requirement exists and the forecast expenditure is deemed efficient then the assets would be replaced through Horizon Power's funding model. The assets would become part of Horizon Power's asset base for any regulatory exercise and as such will earn a return on and of the investment.

The financial model built for this inquiry generates a revenue requirement for each of the towns supplied by Horizon Power and then consolidates these to give an aggregate view of the company as a whole. The revenue requirement for each town indicates the cost of supplying the town with electricity. The determination of the key drivers of the cost to supply is aided by a functional analysis, where the costs of generation, transmission, distribution, retail and overheads are shown separately in the model. Once the key drivers of the cost to supply are identified, reviewed and benchmarked, where possible, with other electricity suppliers, the scope and focus for potential efficiency savings becomes clearer.

The aggregate cost of supply is then carried forward into a set of forecast statutory accounts created for Horizon Power. The statutory accounts serve several purposes:

- The actual sources of customer revenue for Horizon Power (e.g. uniform tariff revenue and commercial contract revenue) are subtracted from the aggregate, cost-reflective revenue requirement to leave a 'balancing revenue' item, from which the subsidies (TEC and CSO) can be derived.
- The financial statements for Horizon Power can be reviewed in advance of any proposed reductions in its operating and capital expenditure programmes so that

the company's ability to remain financially sound under the proposed efficiency assumptions can be assessed.

- Financial indicators, such as net debt as a percentage of total assets or earnings before interest and tax as a percentage of total assets can be reviewed to evaluate the financial position of the company over the review period.

The cost-reflective tariffs for each town, and for Horizon power in aggregate, are determined and compared with the current average regulatory tariff in the SWIS (see section 11).

2.7 Horizon Power's actual funding model

As noted in section 2.1, Horizon Power receives funding from the following sources:

- tariff income − from uniform tariffs applicable to domestic and small business customer and from contractual arrangements with large industrial customers;
- CSO payments − from the State Government's consolidated revenue fund to cover specific programmes, funding shortfalls or rebate schemes;
- Customer contributions – from developers to fund customer requested connections to Horizon Power's networks;
- TEC – from network tariffs charged in the SWIS; and
- Other income – from asset sales, etc.

Horizon Power also has access to debt funding at favourable rates from the State Government and receives equity injections from the State Government to fund specific programmes, such as the PUPP or ARCPSP.[24]

Horizon Power prepares a 5-year Strategic Development Plan[25] each year, which is agreed with the State Government annually and outlines Horizon Power's broad forward direction. Horizon Power's funding levels are agreed annually through the State Budget process and outlined in its annual Statement of Corporate Intent.[26]

Consequently, Horizon Power's operating and capital expenditure is agreed on an annual basis with Government along with other Government Trading Enterprises and Government departments. Horizon Power has advised the Authority that this causes problems regarding Horizon Power's ability to seek efficiencies in its own operations and in its negotiations with third parties because of the inherent uncertainty in its future funding levels.

Horizon Power is concerned that it faces, over the next two decades, a considerable programme of asset replacement activity as assets that were commissioned in the 1980s come to the end of their economic life and need replacing. Horizon Power is aware that the high levels of expenditure required in the future will need to be funded and that its funding sources (tariffs, CSOs and the TEC) will need to increase accordingly.

[24] PUPP is the Pilbara Underground Power Programme and ARCPSP is the Aboriginal Remote Communities Power Supply Programme.

[25] Horizon Power's Strategic Development Plan is commercial in confidence.

[26] Horizon Power's Statement of Strategic Intent is published on its website.

2.8 Practical and data issues

The Authority conducts financial modelling in real terms. For this inquiry this is in prices as at 30 June 2009, to coincide with the beginning of the review period. This has the advantages of:

- ignoring the inherent uncertainty around forecasts of inflation during the review period; and
- clarifying any proposed efficiency targets in real terms rather than having these masked by possible inflationary activity.

Consequently, any figures in the text, tables or charts contained in this report will be in real prices as at 30 June 2009, unless otherwise stated.

The level of expenditure in many of the towns supplied by Horizon Power is very low, which is in contrast to expenditure levels in the NWIS and the consolidated position. To adequately capture expenditures in appropriate detail, all expenditure and asset information relating to the town level is given in $'000s. For the NWIS and for Horizon Power's consolidated position, expenditure and asset values are given in $million.

The NWIS operates in the North West of the State around the industrial towns of Karratha and Port Hedland and their resource and mining centres and serves approximately one third of Horizon Power's customers. As this is an interconnected system it is treated as a single network for the purposes of this inquiry. Therefore, the NWIS cost of service is modelled in place of separate calculations for Karratha and Port Hedland. In doing this the Authority has also combined the East and West Pilbara districts into one and allocated the costs of these combined districts over the NWIS and the other towns in the region (Marble Bar, Nullagine and Onslow).[27]

The Terms of Reference expressly request:

> " that the Authority also take into account the following costs when determining retail tariffs, but is not limited to considering only these costs:
>
> - the efficient generation costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current and committed stock of generation;
> - the efficient network costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current network infrastructure;
> - the level of efficient retail costs that would be applicable in the area that Horizon Power services (both operating and capital costs)"

Consequently, the Authority requested that Horizon Power submit operating and capital expenditures and asset base information at the town level and then further subdivide this into asset information and expenditures at the functional level - generation, transmission, distribution, retail and corporate overhead. This has enabled the Authority to model the cost of service for each town, the NWIS and a consolidated view of Horizon Power at the functional level to determine the impact of each function or combination of functions on the overall cost of service.

The required level of detail in the data provided by Horizon Power and the number of systems this applies to has resulted in a considerable quantity of information having been

[27] Based on kWh of energy sent out to these towns.

received and reviewed by the Authority. Furthermore, as Horizon Power currently forecasts at the district and corporate level and has not traditionally collated historical information at the functional level, the data request from the Authority has caused Horizon Power to undertake a considerable degree of cost allocation across functions. This process has been further complicated by multiple and late revisions to operating and capital expenditures, data omissions in some years and a significant reallocation of assets between functions and between asset classes. This has caused the Authority some concern as to the accuracy and consistency of some of the data received. However the Authority is aware that the inquiry started in the middle of Horizon Power's planning and budgeting cycle and that Horizon Power was required to accelerate its processes and timelines to meet the needs of the inquiry.[28] Furthermore, these data concerns add support to the Authority's suggestion (final recommendation 13) to conduct a second inquiry in three years' time when Horizon Power will have several years' actual data at the town level which can be used for comparative purposes.

[28] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, Schedule B, response reference number 56

3 Escalation of Costs

In submitting its forecast operating and capital expenditure costs, Horizon Power used a variety of escalators to reflect the anticipated future costs of labour, materials and services.

3.1 Background

As mentioned above in section 2.4, Horizon Power purchases approximately 88 per cent of the electricity it sends out from IPPs, via competitively negotiated PPAs. Each PPA typically has its own individually specified escalators and Horizon Power uses the rates outlined in these contracts to forecast forward costs.[29]

For materials and labour costs, Horizon Power has used alternative escalators to the CPI (weighted average of eight capital cities), as it believes the CPI does not reflect the underlying inflation it faces in the markets within which it operates.[30] In the North West of the State, Horizon Power is competing with the resources sector for labour and materials, which drives up prices. The remoteness of the location also adds to increased prices due to the cost of landing goods in the region. The variation in the prices of goods in regional Western Australia compared to Perth is generally recognised. This is evidenced by the publication of a Regional Prices Index in 2007 by the Department of Local Government and Regional Development, and since 1983, Rawlinsons Publishing has produced the Australian Construction Handbook which lists regional indices for all states.[31]

However, no consistent measure of regional prices over time exists. For budgeting purposes, instead of using CPI, Horizon Power adds 20 per cent to current Perth-based unit costs to give what Horizon Power believes are unit capital costs more reflective of current regional costs. These uplifted unit costs are then used by Horizon Power as a starting point from which to forecast future capital project costs (project costs include both materials and contracted labour). Forecast capital project costs are inflated by a long-run average of the Department of Treasury and Finance Building Construction Index (**BCI**),[32] currently calculated between January 1975 and June 2009.

When forecasting its future operating costs, Horizon Power inflates its labour costs by wage rate increases agreed in enterprise arrangements negotiated with staff. These escalators are shown in Table 3.1 below. Horizon Power's operating material costs are inflated by BCI.

In its investigations, PB observed an error in how Horizon Power had calculated the long term BCI and applied the 20 per cent regional uplift to its forecast costs.[33] Instead of applying a 20 per cent uplift to Perth unit costs to reflect regional unit costs and then rolling this forward by BCI, Horizon Power had also uplifted the BCI index by 20 per cent per annum. In doing so Horizon Power had effectively double-counted the impact of the 20 per cent uplift.

[29] Horizon Power (2010), Fact sheet No. 41 – Power Purchase Agreement Escalators

[30] Horizon Power (2010), Fact sheet No. 31 – Rationale for HP's escalators and regional uplifts

[31] Rawlinsons Australian Construction Handbook

[32] Department of Treasury and Finance (2010), a model for forecasting construction cost escalation for non-residential buildings (e.g. hospitals, schools, police stations, etc) with input from various business units within the DTF for use by WA public sector agencies.

[33] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.4.4, pp 53-56

Table 3.1 Comparison of Horizon Power's nominated escalators against the Consumer Price Index (CPI)

Item	2009/10	2010/11	2011/12	2012/13	2013/14
Materials escalators					
• Escalated Buildings Cost index	8.22%	8.22%	8.22%	8.22%	8.22%
• Compounding escalator	1.082	1.171	1.267	1.371	1.484
Labour escalators					
• Horizon Power labour cost escalators	7.7%	6.4%	6.5%	6.4%	6.5%
• Compounding escalator	1.077	1.146	1.220	1.229	1.383
Correct BCI escalator	1.064	1.132	1.205	1.282	1.364
Consumer Price Index					
• Annual actual and forecast CPI growth	2.60%	2.60%	2.60%	2.60%	2.60%
• Compounding escalator	1.026	1.053	1.080	1.108	1.137

Source: PB Final Report, pp 52-53 and RBA Statement on Monetary Policy (August 2010)

Furthermore, in its initial data submission, Horizon Power had not had its use of escalators independently reviewed, which is usually the case to support any forecast cost increases above CPI. For example, Western Power, in its second access arrangement, had its proposed escalation factors independently reviewed and supported by Access Economics.[34]

In the draft report the Authority recognised that, in the past, regional prices have probably risen at a faster rate than the eight cities CPI.[35] However, the Authority expressed concern at how Horizon Power had calculated the long-run average BCI growth figure, basing it on historical values, as this does not provide a like-for-like comparison with the forecast CPI preferred by the Authority.

In particular, the 1975 to 2009 average BCI growth of 6.85 per cent includes periods of high inflation during the 1970s and 1980s. After the recession of the early 1990s, general price inflation has been much lower than previously, with the independent Reserve Bank of Australia (**RBA**) adopting a price (national CPI) target of between 2-3 per cent over the cycle[36] and has generally been successful in achieving this target.

Comparing the CPI and BCI over long periods indicates that BCI growth has been only slightly higher than eight-city CPI growth. From 1975 to 2010,[37] the CPI averaged 5.28 per cent growth per annum, with the BCI averaged 5.67 per cent. Between 1990 and 2010, the CPI averaged 2.62 per cent per annum, while the BCI averaged 2.98 per cent. Such similarity points to using a similar figure for BCI growth as for forecast CPI growth of 2.6 per cent per annum. This is shown in Figure 3.1 below.

However, this long-run similarity masks several periods of divergence between the two series. In particular, between 2002 and 2008, the BCI grew by 9.96 per cent per annum, compared to 3.03 per cent for the CPI. Anecdotal evidence suggests that this may have understated price growth in some regions, especially the Pilbara. Since then, however,

[34] Access Economics (2008), Material and labour cost escalation factors

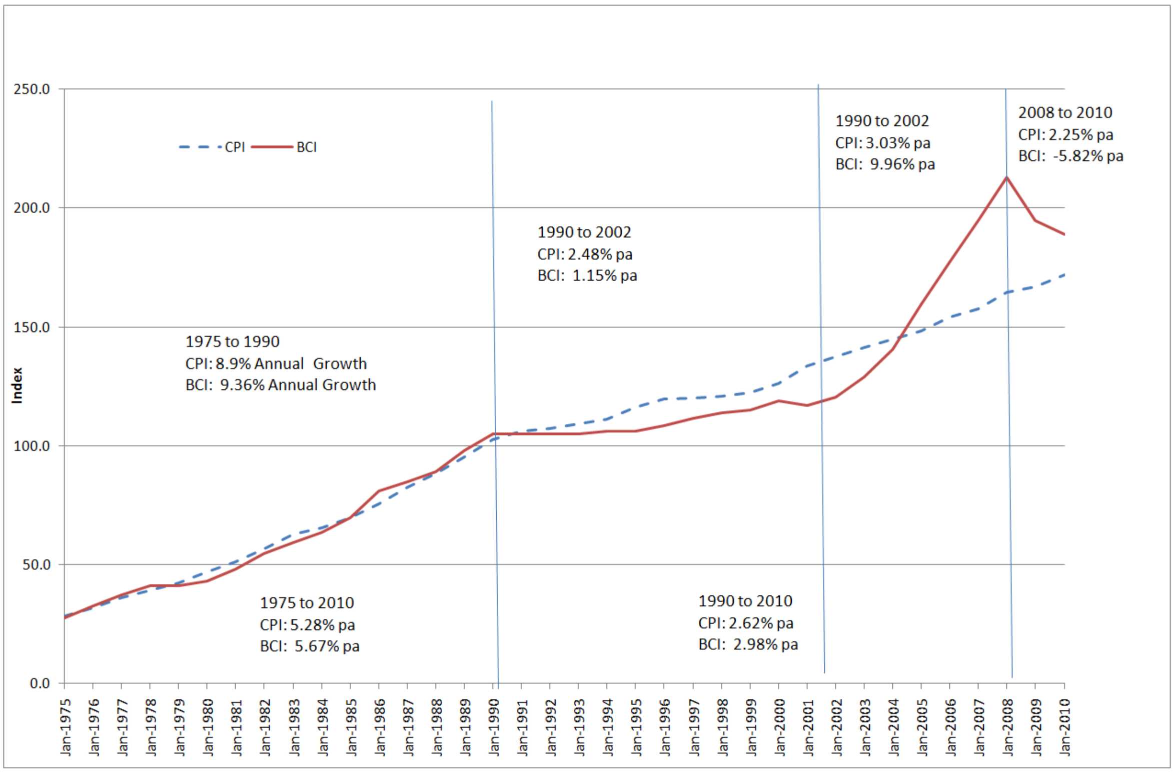
[35] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.4.4, p56

[36] http://www.rba.gov.au/monetary-policy/inflation-target.html

[37] The latest data available

the BCI has fallen 11.3 per cent from its peak in June 2008, which coincided with the onset of the Global Financial Crisis. While Western Australia's economic (and especially investment)[38] prospects may have improved since the peak of the crisis, it is unclear whether rates of escalation of the magnitude experienced between 2002 and 2008 will return.

Figure 3.1 Historical financial year end BCI and CPI (1975 to 2010)



Source: Department of Building and Works, Building Construction Index – Perth.

In the draft report, the Authority accepted that Horizon Power may face growth higher than the CPI, or even the Perth-based BCI. At that stage, however, Horizon Power had not submitted a credible case that this was likely to occur and had only presented a long-run historical average BCI as a predictor of future growth.

Therefore, with the exception of the escalators fixed by PPA contracts, any escalation Horizon Power had assumed in its cost forecasts was ignored in the draft report and removed on the basis that the use of a historically based index to predict future escalation was inappropriate. Consequently, the reductions to either operating costs or capital expenditure costs were applied in real terms which, for this inquiry, were in prices as at 30 June 2009, the beginning of the review period.

In the draft report, the Authority considered that price escalation of the RBA's eight cities CPI forecast was generally appropriate to inflate real prices into nominal terms. The Authority also suggested that, should Horizon Power submit an alternative escalation forecast between the draft and final reports, it should ensure that these forecasts had been independently verified. A possible alternative would be for Horizon Power to use the Department of Treasury and Finance's forecast for the BCI.[39]

[38] Department of Treasury and Finance (2010/11), Budget Paper No.3 Economic and Fiscal Outlook, p22

[39] This is confidential within Government agencies so cannot be reproduced here.

The draft report also stated that if, in later years, actual efficient costs did exceed CPI then a future inquiry could correct for this by allowing an uplift to operating costs in the first (or base) year of the inquiry to reflect the actual cost escalation compared to that assumed in the previous inquiry. This is a forward-looking adjustment and would not retrospectively compensate Horizon Power for the previous review period. This approach is explored in more detail in section 13 below.

The Authority did not make a draft recommendation concerning the issue of escalation for the reasons outlined above. Instead the Authority undertook all financial modelling in real terms.

3.2 Public submissions on the draft report

Four of the seventeen submissions received in response to the draft report commented on price escalation – Horizon Power, WACOSS, the Office of Energy and KPMG. These submissions are available on the Authority's website.[40]

3.2.1 Horizon Power's submission

In its submission, Horizon Power restates its position that BCI is its preferred escalator for materials and non-labour costs (6.85 per cent per annum), for labour costs, an escalator based on wage rates agreed as part of in house enterprise agreements (6.5 per cent per annum) is preferred. This is on the basis that these escalators better reflect the level of regional prices it faces and will continue to experience over the review period.

Horizon Power sought independent advice from Economic Insights on this issue and included the report 'Comments on the ERA Report on Inquiry into the Funding Arrangements of Horizon Power' as part of its submission. This report is also published on the Authority's website.

Horizon Power also suggests that as 'CPI is a historically based index used to predict future inflation' then this did not preclude the use of a forecast BCI index based on historical data.[41]

3.2.2 Other submissions

The submission from KPMG focused solely on the issue of escalation. Comments in the submission note that CPI is a metropolitan area based index and is unlikely to be sufficient for pricing growth in labour and materials costs in the foreseeable future given that base costs are higher in regional Western Australia. KPMG's main comment is:

> "KPMG has not formed any views on the appropriateness of BCI or any other index but would have reservations with CPI being used as a basis to measure the expected increase in labour costs, material costs and non-labour costs in the Pilbara region in the upcoming decade and would recommend an independent study be undertaken to identify the most appropriate index to apply."[42]

The submission from the Office of Energy expressed concern that:

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[40] Economic Regulation Authority website www.erawa.com.au

[41] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, Schedule B, Response reference number 32

[42] KPMG (2011), Submission: Economic Regulation Authority's draft report on the inquiry into funding arrangements of Horizon Power, p2

> "..the Authority was proposing to use a general escalator over escalators that more accurately reflect Horizon's regional costs going forward, potentially significantly understating movements in Horizon's costs and exposing Horizon to increased risks."[43]

WACOSS's submission encouraged Horizon Power to use independently verified escalation forecasts in the future although for this inquiry WACOSS supported the Authority's recommendation to exclude certain escalation from operating cost forecasts.

3.3 Authority comments

The Authority has considered the comments from public submissions on this issue and outlines its treatment of operating and capital cost inflation for the inquiry in the sections below.

3.3.1 Price inflation for capital expenditure

When forecasting capital costs for the review period, the Authority accepts Horizon Power's approach to uplift 2009/10 unit capital costs by 20 per cent over and above Perth costs for that year and use these as a starting point from which to forecast capital costs for the review period. There is some evidence[44] to support that capital costs in the regions are higher than in Perth.

After 2009/10, the Authority does not support the use of Horizon Power's submitted 'escalated capital cost profile' for the financial modelling in the inquiry. Horizon Power's escalated cost profile takes the 20 per cent uplifted unit capital costs and inflates these further by the Perth BCI forecast plus an additional 20 per cent per annum.

This has not been accepted by the Authority as no evidence has been provided to support this ongoing rate of escalation. Furthermore, PB in its report, expressed concern at how Horizon Power had 'applied the 20 per cent uplift to the historical annual escalation rate it has calculated from Perth BCI'. This is because the approach significantly overstates the rate of material escalation as it assumes that:

> "..both the rate of escalation as well as the base cost estimates will be 20% higher than experienced in the broader WA market."[45]

Consequently, the Authority has taken Horizon Power's capital costs in prices at 2009/10 as inputs to the financial modelling process as these capital cost will include the 20 per cent uplift on base Perth costs. Capital costs, along with all other costs have then been deflated by eight-cities CPI as the Authority conducts modelling in real terms, which for this inquiry is in prices as at 30 June 2009.

Within regulatory modelling, the treatment of capital inflation is not a priority as capital expenditure is incurred at nominal prices and (if expenditure is efficient and has been incurred by Horizon Power) added to the regulatory asset base at this nominal or current cost value.

[43] Office of Energy (2011), Office of Energy's submission on the draft report for the inquiry into the funding arrangements of Horizon Power, Attachment 1, p3

[44] Rawlinsons Australian Construction Handbook

[45] Parsons Brinckerhoff (2011), Inquiry into the funding arrangements of Horizon Power – Operating and capital expenditure review, p 54

3.3.2 Price inflation for operating expenditure

The Authority accepts that Horizon Power has faced rapid cost escalation in some of the areas in which it operates, particularly during the resources boom between 2002 and 2008. However, no credible price index relating to operating costs exists at the regional level.

In the absence of a completely suitable indicator, the Authority accepts Horizon Power's position that the BCI is the most suitable indicator to use. While the BCI is a Perth-based index that refers to building rather than operating costs, it is likely to give a better, although still imperfect, indication of the escalation in operating costs faced by Horizon power than the eight-cities CPI.

Forecasting the BCI poses particular problems. Figure 3.1 above shows that the BCI is quite volatile and has encountered periods of very low growth (1990 to 2002), periods of high growth (2002 to 2008) and even a period of contraction (2008-2010). Therefore, regardless of the forecast path, there is a substantial risk that Horizon Power could be over or under compensated for a considerable period.

The Authority agrees with Horizon Power that an extrapolation of past trends is probably the best method for forecasting the BCI. However, it considers that there is no basis for extrapolating from years prior to 1990. In years prior to 1990, the BCI and eight-cities CPI grew at similar high rates, indicating a high level of pure monetary inflation in Australia during this period. Given the RBA is targeting CPI growth of between 2-3 per cent, and is currently forecasting 2.6 per cent, there is little prospect of high monetary inflation in the near future. Escalation above 2.6 per cent needs to come from relative price movements, where the BCI outpaces the CPI, as happened notably between 2002 and 2008.

The average annual growth of the BCI between 1990 and 2010 is 2.98 per cent per annum. The Authority considers that an escalator of approximately this value, rounded to 3.0 per cent, could be the appropriate escalator for Horizon Power to use. Historically, this would over-compensate Horizon Power in some years and under-compensate it in others. However, this is always going to be the case using a forecast of such a volatile data series. The Authority considers that, in the absence of any other evidence, 3 per cent per annum represents a modest and justifiable operating cost escalator for Horizon Power to use. A three per cent escalation factor has been accounted for in the Authority's revised recommended operating cost profile inputs (materials and labour) for modelling in the final report.

The Authority has not accepted Horizon Power's labour escalator based on enterprise arrangements negotiated with staff. This is because the full extent of any wage rises covered by the enterprise arrangement may not be realised given ongoing staff turnover and that there is no evidence to suggest that the enterprise arrangements are efficient.

Caution is required when deviating from the use of CPI as a price escalator. Over time, the historical analysis undertaken by the Authority suggests that BCI and CPI converge although BCI varies more widely around the more stable CPI index. If BCI is adopted as the escalator for Horizon Power on the basis that BCI is more reflective of the costs it faces compared to CPI then the Authority would continue to apply BCI in a later inquiry regardless of how BCI may vary against CPI in the future.

3.4 Final recommendation

1) Horizon Power's level of efficient operating costs include an allowance to reflect escalation by an index calculated from historical Building Cost Index data from 1990 to the date of the start of the review period. For this review period, this escalation figure has been calculated at 3 per cent per annum.

4 Service Standards

4.1 Background

The issues paper for the inquiry into the funding arrangements of Horizon Power outlined the current service standards with which Horizon Power has to comply and the actual service standards against which it reports to the Authority.[46]

Standards regarding the reliability of the electricity supply are detailed in the *Electricity Network (Network Quality and Reliability of Supply) Code 2005*. Horizon Power aims, as far as is reasonably practicable to ensure that:

- the average interruption length (SAIDI[47]) does not exceed 290 minutes per year;
- the number of interruptions does not exceed 16 times per year; and
- any duration does not exceed a continuous 12 hours in length.

One of the key factors affecting Horizon Power's supply interruption measures is the time taken to travel to the source of the problem to carry out the repair. This is a result of the size of Horizon Power's area of supply and the remote nature of many towns.

As part of its technical review, PB determined that Horizon Power has established SAIDI targets as follows:[48]

- 160 minutes for its urban areas;[49]
- 290 minutes for its remote areas;[50] and
- either 350 or 500 minutes (depending upon the characteristics of the supply network) for its remote rural areas.

Based on Horizon Power's 2009/10 performance report, Table 4.1 shows that the average total length of all interruptions to customers (SAIDI) decreased from 336 minutes across the whole system in 2008/09 to 204 minutes in 2009/10. Three towns (Esperance, Norseman and Wyndham) had a SAIDI in excess of 290 minutes in 2009/10. In its performance report of May 2010, Horizon Power stated that it expected all systems to meet the required standards by July 2011.[51]

[46] ERA (2010), Inquiry into the funding arrangements of Horizon Power: Issues paper, Section 4, pp 21-27

[47] SAIDI (System Average Interruption Duration Index) – the total of all customer interruptions in minutes divided by the total number of customer connections averaged over the year.

[48] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.4.2, p51

[49] Urban areas means 'economically critical supply areas (NWIS), as defined in the Reliability code for urban areas'. Horizon Power (2010), Submission to the Executive, Differential Electricity Reliability Measure for certain remote areas, p3

[50] Remote areas means 'other areas of the state with depots, as defined in the Reliability code for "any other area of the state". Horizon Power (2010), Submission to the Executive, Differential Electricity Reliability Measure for certain remote areas, p3

[51] Horizon Power (2010), Performance report, May 2010 (DMS 3195883), p4

Table 4.1 **Average total length of all interruptions of supply to customer premises in minutes (SAIDI) for Horizon Power supply areas in 2008/09 and 2009/10**

	Average Length of Interruption of Supply to Customer Premises (Minutes)	
Town or System	**2008/09**	**2009/10**
NWIS	113	114
Ardyaloon	223	0
Beagle Bay	375	0
Bidyadanga	0	0
Broome	401	61
Carnarvon	207	250
Coral Bay	10	0
Cue	33	173
Denham	85	0
Derby	324	94
Djarindjin	16	0
Esperance	782	611
Exmouth	341	47
Fitzroy Crossing	196	76
Gascoyne Junction	75	0
Halls Creek	333	32
Hopetoun	342	209
Kununurra	372	266
Lake Argyle	325	38
Laverton	520	103
Leonora	30	39
Looma	644	27
Marble Bar	31	38
Meekatharra	173	0
Menzies	0	0
Mount Magnet	667	100
Norseman	384	326
Nullagine	6	110
Onslow	129	217
Sandstone	12	0
Warmun	39	0
Wiluna	175	0
Wyndham	762	327
Yalgoo	9	0
Horizon Power	**336**	**204**

Source: Horizon Power (2010), Network Quality and Reliability of Supply – Performance Report 2009/10, p13

In January 2009, the Authority issued Horizon Power with a notice of failure to comply with its licence,[52] following the 2008 performance review, which identified 17 contraventions of Horizon Power's operating licence.[53] Horizon Power has fully addressed all these contraventions and the notice of contravention was closed on 19 January 2011.

In the draft report for the inquiry, the Authority did not propose a change to existing service level standards (e.g. to require Horizon Power to report to the same service standards as Western Power does for its Access Arrangement),[54] as this would require a change in legislation away from the Electricity Network Reliability Code, which is outside the terms of this inquiry. Instead, the inquiry concentrates on determining the efficient levels of operating and capital expenditure required to deliver service to the existing required standards.

Horizon Power reports regularly to the Authority as part of its licensing requirements and, as such, the Authority is kept informed as to Horizon Power's service performance. The Authority's recommendation for service standards given in the draft report is stated below.

The existing service level standards for Horizon Power be retained, unchanged from their existing form, for the review period.

4.2 Public submissions on the draft report

Twelve of the 17 submissions received commented on the levels of service delivered by Horizon Power across regional Western Australia. These submissions were from Horizon Power, the Goldfields-Esperance Development Commission, the Shire of Broome, the Kalgoorlie-Boulder Chamber of Commerce and Industry, the Office of Energy, the Shire of Carnarvon, the Pilbara Development Commission, the Esperance Chamber of Commerce and Industry, the Mid West Development Commission, West Australian Council of Social Services Inc. (**WACOSS**), the Gascoyne Development Commission and the Regional Development Council. All of these submissions are published on the Authority's website.[55]

4.2.1 Horizon Power's submission

Horizon Power's submission accepted the draft recommendation regarding service standards. However, Horizon Power's submission also commented that:

> "..in the short term, the efficiency savings proposed by the Authority are not achievable and to meet funding shortfalls the business will be driven to cut necessary operating expenditures with an associated deterioration of the services and service level standards provided by the business."[56]

Horizon Power's submission comments on its 'Performance Bargain' with the Minister for Energy by advising that this contains a direct relationship between service standards and cost. Horizon Power states that:

[52] *Section 32 Electricity Industries Act 2004 – Notice of Failure to Comply with Licence*, on the Authority web site, under "Horizon Power": http://www.erawa.com.au/2/245/51/electricity_licensing__licence_holders.pm

[53] Ernst and Young (November 2008), *Integrated Regional Licence (EIRL2) Performance Audit Report*

[54] www.erawa.com.au, Amended proposed revisions to the Access Arrangement for the South West Interconnected System owned by Western Power, pp 5-11

[55] Economic Regulation Authority website www.erawa.com.au

[56] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, p12

> "The Performance Bargain specifies service standards in exchange for Horizon Power's agreed funding."[57]

The Performance Bargain contains a mix of service standards. Some of these are consistent with the legislative requirements of the *Electricity Network (Network Quality and Reliability of Supply) Code 2005* and the *Code of Conduct for the Supply of Electricity to Small Use Customers 2008* and some other service standards are unique to the Performance Bargain. Horizon Power expands on this by identifying to the Authority that the business has differing minimum efficient costs across its supply area for delivering a given level of service. Horizon Power's submission comments that the 'inevitable consequence' for a profit maximising commercial organisation would be to provide varying service standards from area to area, which would not be a socially equitable outcome. Consequently, Horizon Power states that this is an issue that it carefully considers when balancing its economic efficiency objectives with its social objectives.

4.2.2 Other submissions

All of the other submissions that commented on levels of service delivery suggested that service standards should not deteriorate as a result of any efficiency targets or expenditure reductions proposed for Horizon Power by the inquiry.

All of the submissions from regional bodies (Chambers of Commerce, Shires and Development Commissions, with the exception of the Esperance Chamber of Commerce), noted that on average Horizon Power has delivered improved reliability of power supplies in their areas. Within the submissions this was often linked to Horizon Power's decentralised operating structure, which was seen as providing regionally-based staff with localised knowledge who were better placed to quickly respond to power supply interruptions. The majority of submissions from regional bodies opposed a move away from the current decentralised business model for Horizon Power, although a return to centralised operations management was not recommended anywhere in the draft report.

The submission from the Esperance Chamber of Commerce and Industry (**ECCI**) noted that:

> "..the Esperance community suffers from regular and prolonged power outages that would not be acceptable in the Metropolitan area."[58]

In the opinion of the ECCI any proposed reduction in Horizon Power's budget would only exacerbate the power interruption problems in the area.

The submission from the Office of Energy:

> "..had anticipated that the Authority might investigate the question of appropriate service level standards for Horizon Power's service areas and the impact of a variation in standards on the level of cost-reflective tariffs."[59]

The Office of Energy's submission suggested that if the relationship between standards and costs was better understood then this could help inform an assessment of the

[57] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, p10

[58] Esperance Chamber of Commerce and Industry (2011), Submission to the Economic Regulation Authority regarding the inquiry into the funding arrangements of Horizon Power, p1

[59] Office of Energy (2011), Office of Energy's submission on the draft report for the inquiry into the funding arrangements of Horizon Power, Attachment 1, p1

appropriateness of the existing standards and so determine if changes to the standards would better service the interests of customers and the public.

The submission from WACOSS:

> "..commends Horizon Power on a significant decrease in the average total length of all power interruptions to their customers."[60]

WACOSS' submission supported the Authority's draft recommendation to retain the existing service standards for the review period.

4.3 Authority comments

The Terms of Reference for the inquiry do not expressly request that the Authority review Horizon Power's current levels of service, nor how efficient costs would alter if service standards were to be changed. However, assumptions about the underlying service standards are inherent within the inquiry if the Authority is tasked with determining an efficient level of costs that delivers a given level of service.

Although Horizon Power has a Performance Bargain with the Minister for Energy that contains several service standards, this should not detract from the requirements of the two legislative codes[61] against which Horizon Power has to deliver services in line with its operating licence. It is the service standards defined by the legislative codes that the Authority monitors and reports on as part of its licensing activities.

If the Authority were to consider an alternative set of service standards to those currently detailed by the legislative codes this would firstly require demonstration of the fact that customers are willing to pay for and/or accept revised, or as Horizon Power suggest, differential service standards in different regions even though this is contrary to a socially equitable framework. The adoption of new or differing service standards would require a legislative change to revise the current content of the two codes covering service standards. Finally, the Authority would need to determine the level of efficient costs that delivers the revised service standards which, under the current funding model for Horizon Power and in the absence of cost-reflective tariffs, would be funded through a subsidy via a CSO or the TEC.

The Authority supports the sentiment, expressed in many of the other submissions that comment on service standards, that there should be no deterioration in the quality or reliability of the power supply or in the customer and billing services provided by Horizon Power as a result of the operating cost or capital expenditure cost reductions suggested by the Authority as part of the inquiry. Rather, Horizon Power should be able to deliver existing service standards at a reduced cost as it becomes more efficient.

For these reasons the Authority is not proposing any change from the draft recommendation on service standards and the final recommendation is shown below.

[60] WACOSS (2011), WACOSS submission to the inquiry into the funding arrangements of Horizon Power – draft report, p2

[61] These codes are the *Electricity Network (Network Quality and Reliability of Supply) Code 2005* and the *Code of Conduct for the Supply of Electricity to Small Use Customers 2008.*

4.4 Final recommendation

2) The service level standards for Horizon Power be retained, unchanged from their existing form, for the review period.

5 Demand Forecasts

Horizon Power's forecasts of operating and capital expenditure are based on a forecast of the demand for energy across its area of supply. The Authority asked PB to consider Horizon Power's demand forecasting as part of its technical review.

5.1 Background

Horizon Power has a five stage process for determining its ten year demand and energy forecasts.[62] These forecasts are used to inform investment decisions and asset management planning concerning network augmentation and generation requirements.

Over the review period Horizon Power forecasts that overall demand will increase by six per cent for residential customers and just under four per cent for existing commercial customers. This is driven by growth in the numbers of connections of just under three per cent per annum for residential properties and just over two per cent per annum for commercial connections.[63]

In the NWIS, Horizon Power has just over 13,000 commercial and residential customers, including 18 large industrial customers. All customers are covered by the uniform tariff policy with the exception of 18 large industrial customers as these have commercial supply contracts with Horizon Power. Over the past six years Horizon Power has experienced increasing demand growth of six per cent in the NWIS, driven mostly by population growth.[64]

Horizon Power is forecasting that the demand growth profile for the NWIS will change. Maximum daily demand is expected to increase by 16 per cent in 2010/11 due to increases in demand from major industrial customers, (e.g. a new 6.2MW load from the connection of the new bulk commodity export berth by the Port Hedland Port Authority at Utah Point on Finucane Island[65]). This increase in forecast demand is shown in Figure 5.1 below.

The step increase of 25 per cent in the maximum demand forecast from 2009/10 to 2010/11 results from the combined effect of lower summer temperatures tempering maximum demand in 2009/10, the 16 per cent increase from new demand and the annual organic growth from residential and small commercial customers.

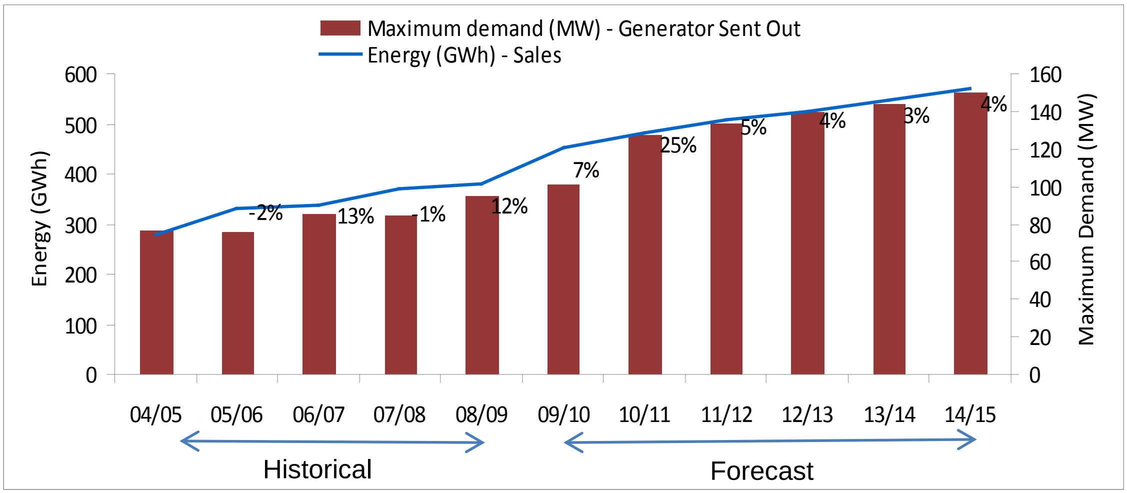
[62] Horizon Power (2010), Fact sheet No. 1 – The demand and energy forecasting process

[63] Horizon Power, (2010), Spreadsheet 'HP#3295715v1_connection totals'

[64] Horizon Power (2010), South Hedland Power Station – Business case for new generation, p7

[65] Port Hedland Port Authority website, http://www.phpa.wa.gov.au/utah_point.asp

Figure 5.1 Historical and forecast energy demand for NWIS



Source: Horizon Power – South Hedland Power Station, Business Case for New Generation, Figure 4, p8

Horizon Power currently has contractual arrangements for 139MW of capacity in the NWIS (from PPAs with Alinta and ATCO) until the end of December 2012 when its PPA with Alinta expires. At this point available generation capacity falls to 80MW.

The alternatives Horizon Power considered for providing additional generation capacity in the NWIS are discussed in more detail in section 8 below.

PB, as part of its review, examined the accuracy and validity of Horizon Power's demand and energy forecasting process and concluded that:

> "Horizon Power approaches its annual demand and energy forecasting using an informed and detailed bottom-up approach."

However, PB was concerned that the company did not place much emphasis on incorporating independent 'top-down' analysis, which is typically the case, in PB's experience, for other electricity suppliers.[66]

Where the demand forecast is driving a particular investment project, such as the proposed augmentation of the Fairway Drive transmission substation in Broome, PB reviewed Horizon Power's underlying demand projection in more detail. In this particular case, PB proposed reductions to the forecast capital expenditure in line with its own considerations on forecast demand growth and proposed alternative short-term arrangements. This is also explained in more detail in section 8 below.

PB did not suggest any revisions to Horizon Power's current demand forecast or its energy and demand forecasting methodology and processes.

The Authority did not make a draft recommendation concerning Horizon Power's demand and energy forecasting. However, in the draft report the Authority did note PB's comments on Horizon Power's demand forecast and also outlined the approach it would take in a subsequent inquiry if Horizon Power's current demand forecast proved to be inaccurate.

[66] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.3.3, p45

5.2 Public submissions on the draft report

Only three of the submissions received in response to the draft report commented on demand growth. These were the submissions from Horizon Power, the Shire of Broome and the Regional Development Council. All of these submissions are available on the Authority's website.[67]

5.2.1 Horizon Power's submission

Horizon Power's submission commented that the Authority had used an earlier version of the Demand and Energy Forecast in its modelling for the draft report and not the approved version.[68] The Authority advised Horizon Power of the version of the demand and energy forecast used for modelling in the draft report and Horizon Power subsequently confirmed that this was the approved version.[69] Consequently, the Authority used the same approved demand and energy forecast in modelling for the final report.

5.2.2 Other submissions

The submission from the Shire of Broome commented that:

> "The Shire of Broome is experiencing a period of massive growth which is expected to extend into the next 30 to 40 years and is under sustained pressure."[70]

The submission also listed six major local projects indicative of the current growth in the area. The list included Landcorp's Broome North residential subdivision of 4,800 new residential lots, including new schools and associated commercial and industrial land, the proposed Browse Liquified Natural Gas Hub at James Price Point and the development of a new regional waste facility and relocation of the airport site both intended for north Broome.

The submission from the Regional Development Council noted that:

> "The Horizon Power service provision area encompasses most of the fastest growing regions in the State."[71]

Neither of the two submissions commented on the appropriateness or accuracy of Horizon Power's demand and energy forecast.

5.3 Authority comments

PB's comments on the demand and energy forecast were noted in the Authority's draft report and Horizon Power did not update its demand and energy forecast following publication of the Authority's draft report.

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67 Economic Regulation Authority website www.erawa.com.au

68 Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, p7

69 Horizon Power (2011), Email from Horizon Power 22 February 2011 (D62306)

70 Shire of Broome (2011), Submission to the funding arrangements of Horizon Power, p1

71 Regional Development Council (2011), Submission to the inquiry into the funding arrangements of Horizon Power, p2

As such the Authority has no further comments to make on the demand and energy forecast that was considered in the final report and accepts Horizon Power's demand and energy forecast for the review period.

6 Initial Capital Base

This section outlines the valuation of Horizon Power's asset base for the inquiry.

6.1 Background

At disaggregation from Western Power Corporation (**WPC**) on 1 April 2006, assets were transferred to Horizon Power at their written down historic cost value (**WDV**), excluding any accumulated depreciation ($180.1m nominal in Table 6.2 below). In the years immediately following disaggregation, Horizon Power undertook a review of all inherited assets and assigned a remaining asset life to each asset.

To reflect the operation of an efficient regional power corporation, the Initial Capital Base (**ICB**) value is only rolled forward by efficient new capital expenditure. PB was asked to review the efficiency of Horizon Power's historical capital expenditure as part of its wider technical advice to the Authority.

PB outlined its findings on Horizon Power's historical expenditure in Chapter 6 of its report.[72] In summary, PB found some variance between Horizon Power's actual capital spend when compared to budget (18 per cent in 2006/07, 13 per cent in 2007/08 and 3 per cent in 2008/09). The majority of these variances could be accounted for and were, in the main, outside the control of Horizon Power. On page 60 of its report, PB commented:

> "With regards to capex, PB has identified a clear trend of underspending against budget. However, as noted above, this has largely been due to factors which were outside the company's control and the underspending is reducing as a percentage of budgeted expenditure."

In its report, PB's noted that Horizon Power has been undergoing a period of 'establishment and restructuring' since inception[73] and as such can be expected to show increases in operating costs and staff numbers. Consequently, PB did not recommend any reductions to historical operating and capital expenditure levels. However, PB also noted that it would expect costs and staff numbers to decrease as the company realises efficiencies. This comment supported PB recommendation for reductions to future operating costs as detailed in section 7.

For modelling purposes, Horizon Power provided the Authority with a copy of its Fixed Asset Register as at 1 April 2006, coinciding with its disaggregation from WPC. This Fixed Asset Register data and information was used to determine ICB values and weighted average asset lives by function and by asset class for each town and for each district. The data for new capital additions, disposals and gifted assets was also sourced from Horizon Power's fixed asset registers. All new capital additions were depreciated using average asset class lives in accordance with Horizon Power's Budget Model.[74]

To calculate an ICB at 1 July 2009 in the draft report, the Authority firstly took the value of Horizon Power's asset base at the point of disaggregation from Western Power Corporation, on 1 April 2006 and then rolled this value forward by adding efficient new

[72] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 6.2, p63

[73] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 8.8, p89

[74] Horizon Power (2010), Fact Sheet No. 38 – Asset Classes and Asset Life Expectancy

capital net of asset disposals and depreciation to give a closing asset value at 30 June 2009. This figure, $264.1 million (real as at 30/6/2009), was then carried forward to become the opening ICB value at 1 July 2009. The figure was not inflated as financial modelling for the five year review period is carried out in real prices as at 30 June 2009.

Assets gifted to Horizon Power either as cash or as physical assets by customers, developers, the State Government or Federal Government between disaggregation and 30 June 2009 were excluded from the asset base as they were not directly funded by Horizon Power.[75]

Given PB's comment on and assessment of past expenditures, the Authority did not propose any adjustments to net new capital additions between 1 April 2006 and 30 June 2009.

In its response to the issues paper Horizon Power suggested that:

> "..utilisation of the accounting data will significantly undervalue the assets from an economic perspective."

Horizon Power expanded on this by stating that, given the age of some of its infrastructure assets, some assets have been depreciated to zero and have no value in Horizon Power's asset base and therefore will not earn a return.[76]

After reviewing the available evidence, the Authority used the historic cost valuation of Horizon Power's asset base in the calculation of revenue requirement for the draft report. In some instances, in regulatory economics, a current cost valuation methodology, such as a Depreciated Optimised Replacement Cost (**DORC**) or Optimised Deprival Value (**ODV**), is used to establish an ICB (e.g. in Western Power's first access arrangement period, 1 July 2006 to 30 June 2009, the Authority was obliged to take the Minister for Energy's DORC valuation of Western Power's ICB).

The Authority's reasons for using a written down historic cost ICB valuation in the draft report were largely that:

- the Authority was aware that some assets have a written-down value of zero in Horizon Power's asset register. Typically these assets were commissioned before Horizon Power was established and so would have earned a return for the previous owner, WPC, and been fully depreciated. Therefore the Authority suggested that these assets should not earn a further return for Horizon Power;
- the Authority was unable to establish an ODV for Horizon Power using the regulatory methodology because of circularity issues. ODV requires the calculation of anticipated future income streams generated by each asset. The establishment of future income streams is dependant upon the size of the TEC, calculated by the cost of service model, which uses the ODV as an input; and
- the calculation of the revenue requirement was relatively insensitive to the ICB, when compared with the other elements of the revenue requirement calculation. This is explained in more detail in section 10 below.

[75] At the point when these gifted assets reach the end of their economic life and need to be replaced the regulatory methodology assumes that they are then included into the regulatory asset base as new capital assets and valued at the current cost of their replacement.

[76] Horizon Power (2010), Submission to the ERA Issues Paper, Section B 4.1 Asset Valuation, p23

The historic cost ICB valuation at 30 June 2009 in the draft report approximately reconciles back to Horizon Power's statutory accounts for 2008/09 as shown in Table 6.1 below.

Table 6.1 Draft report − reconciliation of draft historic cost valuation to Horizon Power's 2008/09 statutory accounts ($m real at 30/6/2009)

Item	Amount ($m)
Horizon Power Statutory accounts 2008/09	
• Land	7.545
• Leasehold buildings and equipment	18.225
• Plant and equipment	372.172
Sub-total non-current assets	397.942
Less	
• Work in progress	99.060
• Decommissioned assets	5.497
• Gifted assets	22.258
Regulatory asset base from statutory accounts	271.112
ERA regulatory ICB calculated from Horizon Power's fixed asset register	264.086
Variance in calculated depreciation charge between statutory accounts and ERA financial model	-3.506
Overall variance between asset bases (not reconciled)	3.520

Source: Horizon Power's statutory accounts for 2008/09, spreadsheet HP=326434 and ERA analysis

The rolling forward of Horizon Power's ICB, at the aggregate level from 1 April 2006 to 30 June 2009 is shown in Table 6.2 below. The closing ICB value in the preceding year was inflated by CPI to give the opening value ICB in the following year. As mentioned above, the exception is the final year where the closing value at 30 June 2009 is taken forward to 1 July 2009 as from this date all financial modelling data was shown in prices as at 30 June 2009.

Table 6.2 Draft report − derivation of Horizon Power's aggregate ICB to 30 June 2009 ($m nominal)

Item	1 April 2006	30 June 2006	30 June 2007	30 June 2008	30 June 2009
Opening value		182.9	180.4	174.1	232.6
Net additions		-2.7	0.2	64.2	40.7
Depreciation		-3.5	-14.0	-9.0	-9.2
Closing value	180.1	176.7	166.6	229.2	**264.1**

Source: ERA analysis

Based on this analysis, the Authority's recommendation on the ICB in the draft report is stated below.

A historic cost valuation of $264.1 million (in real prices at 30/6/2009) be used for Horizon Power's initial capital base as at 1 July 2009.

6.2 Public submissions on the draft report

Three of the submissions received in response to the draft report commented on the valuation of Horizon Power's ICB. These were the submissions from Horizon Power, the Office of Energy and WACOSS. All of these submissions are available on the Authority's website.[77]

6.2.1 Horizon Power's submission

In its submission in response to the draft report, Horizon Power argued that the historic cost ICB valuation of $264.1m (real at 30/6/2009) used in the draft report was too low. The reasons for this were that:

- asset data transferred from WPC at disaggregation was 'not comprehensive and there is no evidence to support that indexed historic cost was applied consistently prior to disaggregation';
- at the point of disaggregation, no reserves (either cash or accumulated depreciation) were transferred;
- in Horizon Power's opinion this does not result in ongoing financial sustainability; and
- too low a valuation of ICB will not deliver a sufficient return on and of investment to provide for adequate asset replacement in future years.

During the course of the inquiry, Horizon Power undertook a depreciated replacement cost revaluation of its complete asset base. The starting points for this valuation were two earlier studies conducted by SKM on the NWIS and the other islanded systems.[78] Horizon Power took the 'replacement cost' asset valuations for each of its assets from the two SKM reports and then adjusted these valuations downwards by depreciation to reflect the reduced value of each asset given its remaining useful economic life.

In undertaking a depreciated replacement cost valuation Horizon Power has valued its asset base at $747.4m (real at 30/6/2009). This valuation included gifted assets as Horizon Power is unable to distinguish these assets within its asset base.

6.2.2 Other submissions

The WACOSS submission agreed with the Authority's draft recommendation to use a historic cost valuation of Horizon Power's ICB as this method of valuation:

> "..seems the most suitable for Horizon Power's current circumstances."[79]

However, WACOSS questioned the 'accuracy and appropriateness' of using a historic cost valuation in future inquiries.

The submission from the Office of Energy disagreed with the exclusion of 'gifted assets' from Horizon Power's asset base, on the basis that:

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[77] Economic Regulation Authority website www.erawa.com.au

[78] SKM (2010), '2009 Horizon Power Asset Valuation of the NWIS' and '2010 Horizon Power Replacement Cost Valuation of the Non-Interconnected System (NIS)'

[79] WACOSS (2011), WACOSS submission to the inquiry into the funding arrangements of Horizon Power – Draft report, p3

> "Like any other capital expenditure that Horizon funds, either through equity or debt, these expenditures should be rolled into Horizon's capital base and it is appropriate for Horizon and its shareholder to receive a return of and return on this investment. Similar to any other asset, Horizon will have to replace these assets at the end of their economic life."[80]

The Office of Energy also noted that a proportion of Horizon Power's ICB would have also contained gifted assets but the draft report did not appear to 'recommend discounting of Horizon's asset base' to remove these gifted assets.

6.3 Authority comments

The Authority understands that the driving influences behind Horizon Power's valuation of its ICB at the depreciated replacement cost of $747.4m (at 30/6/2009) are its ongoing financial sustainability and how it is currently funded through tariff income and additional subsidies. In particular, Horizon Power notes that the number and value of asset replacements required over the next two decades would result in a significant increase in the funding it requires. This will mean that when asset replacements fall due they will be accompanied by increases in cost-reflective tariffs and hence the TEC, or CSO payments or increases in Horizon Power's debt and equity funding.

Whilst appreciating Horizon Power's concerns, the Authority has decided not to accept Horizon Power's depreciated replacement cost valuation of its ICB.

Firstly, it is not generally considered appropriate to provide regulated companies with a return on and of their assets that is greater in present value terms than the amount the regulated companies would have initially paid for the assets. To do otherwise would be to give the regulated companies a windfall gain.

Secondly, the Authority is aware that Horizon Power's depreciated replacement valuation includes assets that were originally funded by third parties. To include these assets in Horizon Power's asset base would result in Horizon Power earning a return on, and so benefiting from, assets that it did not pay for.

Thirdly, Horizon Power argued that a higher valuation would provide them with income to pay for asset replacements in the future. The Authority does not accept that it is appropriate to have current customers fund expenditure that occurs well into the future. Instead, the rate of return provided to Horizon Power allows it to fund those replacement assets at the time the expenditure is incurred.

Subsequent to the draft report, the Authority has undertaken financial modelling using Horizon Power's depreciated replacement cost valuation of its asset base and notes that this delivers key financial indicators that suggest Horizon Power would be overcompensated. For example, using credit rating criteria, Horizon Power appears well above investment grade.[81]

The Authority then reviewed the comments from public submissions on its use of written down historic cost valuation of Horizon Power's ICB and concludes that there is support for the view that the valuation at $264.1m (real at 30/6/2009) is too low. This mainly arises from the use of the WDV of assets at disaggregation as this WDV, ($180.1m real at 30/6/2009), represents the depreciated cost of the assets in nominal dollars at the time

[80] Office of Energy (2011), Office of Energy's submission on the draft report for the inquiry into the funding arrangements of Horizon Power, Attachment 1, p2

[81] This translates to a A- rating under Standard and Poors rating criteria and AA rating under the New South Wales Treasury rating criteria.

the asset was commissioned. Consequently, the cost of each asset has not been appropriately inflated and nominal depreciation applied between its commissioning date and disaggregation in 2006. However, the Authority did inflate (by CPI) the written down valuation of ICB between 1 April 2006 and 30 June 2009 in line with Table 6.2 above.

The financial modelling that resulted from using a historic cost WDV valuation for Horizon Power showed that there were insufficient profits from which Horizon Power could pay dividends to its shareholder.

Instead, the Authority has adopted an alternative but standard approach to calculating an ICB. This is to calculate an alternative inflation-adjusted historical cost valuation of Horizon Power's ICB by:

- assuming the book value of depreciation per year is constant in order to calculate the initial value of an asset at the time it was capitalised as follows;

$$\text{Initial Value at capitalisation} = \text{Write Down Book Value} \times \left(\text{Age of the asset} + \text{Remaining life of the asset}\right) \div \text{Remaining life of the asset}$$

- inflating every prior year closing asset value by the appropriate historical CPI to derive the opening asset value of the following year, and then use this nominal opening value to calculate nominal depreciation based on the remaining life of the asset;

This inflation adjusted and nominal depreciation calculation was applied each year from the commissioning date of the asset until 1 April 2006 to each asset in Horizon Power's fixed asset register to derive an inflation-adjusted historical cost asset value as at 1 April 2006. The value $307.3m (nominal) was then rolled forward using the same methodology as was used in the draft report, namely to exclude gifted and disposed assets, to give an ICB value of $388.7m (nominal) at 30 June 2009.

Table 6.3 Final report − derivation of Horizon Power's revised aggregate ICB to 30 June 2009 ($m nominal)

Item	1 April 2006	30 June 2006	30 June 2007	30 June 2008	30 June 2009
Opening value		312.2	311.5	306.6	361.8
Net additions		-2.6	0.6	64.3	40.9
Depreciation		-4.5	-18.3	-14.2	-13.9
Closing value	307.3	305.2	293.4	356.6	**388.7**

Source: ERA analysis. Totals may not add due to rounding.

The Authority is aware that the inflation-adjusted historical cost valuation contains gifted assets existing prior to and carried over at disaggregation in 2006. The value of these gifted assets cannot be excluded from the inflation-adjusted historical cost ICB as Horizon Power is unable to distinguish, from its inherited asset base at 1 April 2006, which of these assets were gifted. Therefore the asset base value is higher than it would otherwise be.

The final consideration in the determination of the ICB was to review the impact of this ICB on Horizon Power's financial position. Economic regulation generally calculates revenue requirement on the basis that the service provider maintains an investment grade credit rating. An investment grade rating is an opinion, from a credit rating company such as Standard and Poors (**S&P**) of the creditworthiness of a company as a guide to its attractiveness as an investment. There is no definitive set of financial indicators that can be used to unequivocally determine that a company is investment grade. However, the Authority reviewed Horizon Power's financial indicators against rating criteria from the

New South Wales (**NSW**) Treasury and S&P. With an ICB of $388.7m, as calculated using the inflation-adjusted historical cost methodology, the NSW Treasury approach indicated an AA rating for Horizon Power and the S&P approach suggested BBB over the review period.[82]

In particular, the Authority notes that gearing (the proportion of debt to equity) trends downwards from 68% in 2009/10 to 65% by 2013/14 and net profit ranges from $36m to $45m (nominal) over the review period.

Despite the Authority's concerns that the inflation-adjusted historical cost ICB contains contributed assets, this value results in an investment grade rating for Horizon Power. As such the recommended ICB value results in ongoing financial sustainability by ensuring improving gearing over the review period, the payment of dividends from 2012 onwards and a stable level of retained earnings.

The Authority's final recommendation on the value of Horizon Power's ICB is shown below.

6.4 Final recommendation

3) For the purpose of this inquiry, an inflation-adjusted historical cost asset valuation of $388.7m (in real prices as at 30/6/2009) be used for Horizon Power's initial capital base as at 1 July 2009.

82 Two set of rating criteria had been used for analysing Horizon Power's financial sustainability; these are Standard and Poor's corporate rating criteria and NSW Treasury business rating criteria. The guidance displayed in the both of the matrices that underly the credit ratings make an explicit linkage between financial ratios and levels of business risk. Therefore, the rating result reflects an analysis of a business in terms of its financial ratios. The Authority used Fund from Operation (FFO)/Interest Bearing Liability to assess the cash flow adequacy and leverage ratio in assessing Horizon Power's financial sustainability.

7 Operating Costs

This section reviews Horizon Power's forecast operating cost expenditure over the review period and suggests the level of efficient operating expenditure that would be incurred by a prudent regional electricity service provider.

7.1 Background

Horizon Power's total operating costs comprise costs that:

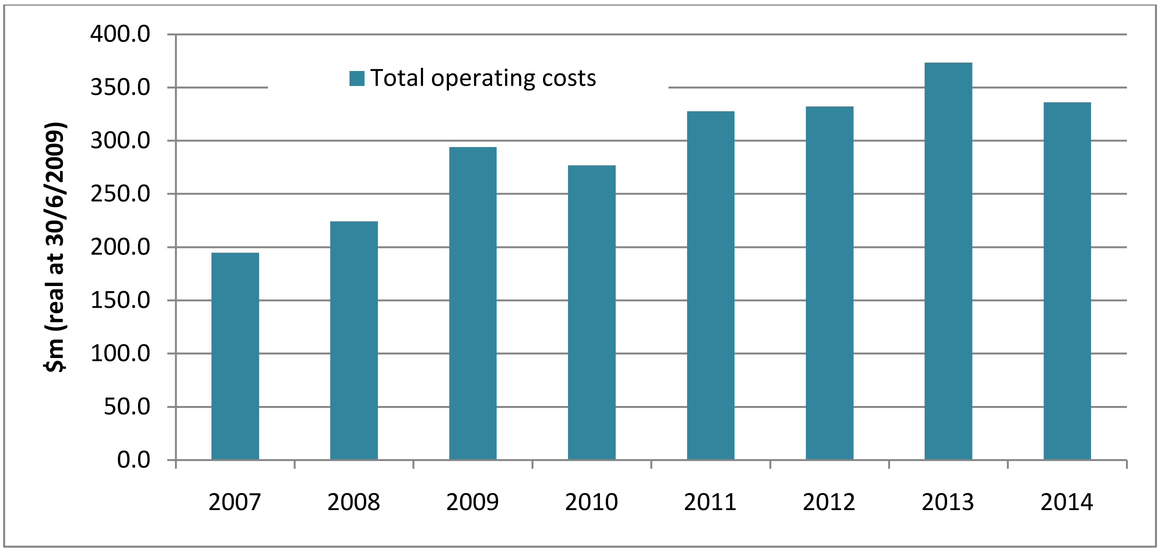
- are non-controllable in the short-term (e.g. costs determined by contract terms, especially for electricity supply contracts Horizon Power has with third parties); and
- controllable (e.g. costs that are able to be effectively managed over the short-term such as material and labour costs).

The Authority has also considered the appropriate efficiency target to apply to Horizon Power's controllable operating costs. In addition, and in line with the Terms of Reference for the inquiry, the Authority has also considered the impact of renewable energy costs on Horizon Power's operating costs.

Total operating costs

After removing any assumed escalation, Horizon Power incurred average annual operating costs of $237.7m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted average annual (actual and forecast) operating costs of $329.3m (real at 30/6/09) over the period 2009/10 to 2013/14. This is an increase of 38.5 per cent in the average annual expenditure between the two periods. The annual expenditure is shown in Figure 7.1 below.

Figure 7.1 Actual and forecast total operating cost levels over time ($m real at 30/6/09)



Source: Horizon Power - Consolidated town report data 16/9/2010 and ERA analysis

Horizon Power supplied actual and forecast operating costs by function (generation, transmission, distribution, retail and overhead) for the review period. The Authority reviewed this functional analysis of operating costs to determine which functions or combination of functions was driving operating cost growth. The individual cost functions comprising forecast operating costs are shown in Table 7.1 below, which demonstrates that generation and overhead operating costs are the main drivers of total operating costs and together contribute over 93 per cent of total costs over the review period.

Table 7.1 Drivers of forecast operating costs by function ($m real at 30/6/2009)

Function and main drivers	2010	2011	2012	2013	2014	Total	Per cent of total
Generation	175.0	208.6	212.1	251.5	215.4	1,062.5	64.5
Transmission	1.9	2.4	2.4	2.7	4.4	13.7	0.8
Distribution	18.1	6.4	6.7	7.0	8.7	46.9	2.8
Retail	9.4	10.1	9.9	10.0	10.0	49.3	3.0
Overhead	72.7	100.5	101.1	102.2	97.8	474.3	28.8
Total operating expenditure	277.0	327.9	332.3	373.3	336.3	1,646.7	100.0

Source: Horizon Power - Consolidated town report data (16/9/2010) and ERA analysis

The 'spike' in total operating costs in 2012/13 ($373.3m real at 30/6/2009) is associated with additional electricity purchases required to cover demand whilst the new power station in South Hedland is being constructed.[83] Energy costs in the NWIS increase from $71.8m in 2011/12 to $106.7m in 2012/13 then reduce back to $66.6m in 2013/14 (all real as at 30/6/2009). Horizon Power has advised the Authority that because of delays in obtaining budget approval for the South Hedland power station project from the State Government, Horizon Power's initial commissioning date for the new power station, November 2012, has been delayed until 1 July 2013. This was on the assumption that budget approval would be forthcoming by the end of 2010. Had the original timeframe been met then additional energy purchases would not have been required.[84]

Horizon Power has informed the Authority that it has not received funding approval for the South Hedland power station project by the time this report was delivered to Government. When the project is approved the initial project cost will require updating. As updated costs were not received from Horizon Power, and in the absence of any other information, the Authority has modelled the initial project costs as part of the final report.

Table 7.1 above also demonstrates a clear increase in overhead operating costs from $72.7m (real at 30/6/2009) in 2009/10 to $100.5m (real at 30/6/2009) in 2010/11, after which overheads remain at around $100m per annum. This illustrates how the functional analysis of operating costs is affected by Horizon Power's current practice of allocating actual costs (2009/10) at the town/functional level and forecasting (from 2010/11 onwards) the majority of its operating costs at the district level. District costs and corporate overheads are combined in Table 7.1 as total overheads. A further analysis of overheads is undertaken below.

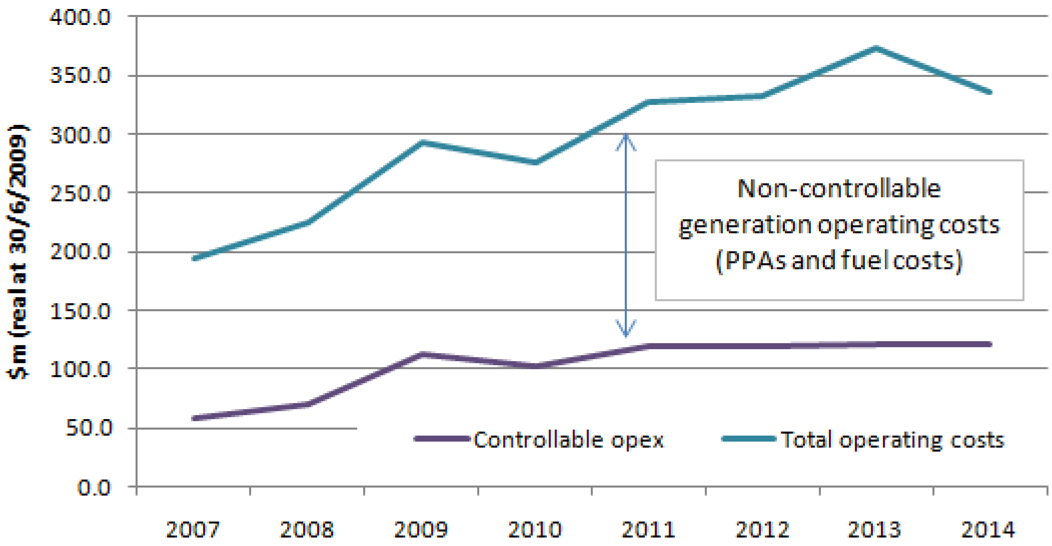
However, not all of Horizon Power's operating costs are controllable in the short term. This non-controllable element of operating costs (just over 60 per cent of total operating costs) is predominantly those generation operating costs that relate to PPA agreements

[83] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 7.4, p74

[84] Horizon Power (2010), email received 16 November 2010

and fuel purchases. This is illustrated in Figure 7.2 below and explained in more detail below.

Figure 7.2 Horizon Power's total operating costs and controllable operating costs ($m real at 30/6/2009)



Source: Horizon Power town reports at 8 and 16 September and ERA analysis

The Authority noted the increase in forecast energy purchase operating costs by just under $35m in 2012/13 to cover demand prior to the South Hedland power station being commissioned. In the draft report, the Authority considered that any additional costs incurred by Horizon Power and identified by Horizon Power as resulting from delays in receiving funding approval should not be passed through to the TEC and consequently to SWIS customers. The Authority removed this forecast expenditure from the generation operating costs included in the cost of service calculation. Furthermore, there is a risk that this increased level of energy purchase costs will continue if the power station project is further delayed and so the Authority also recommended that any additional operating cost increases resulting from a delay of the South Hedland generation project are borne by Horizon Power (or by its shareholder, the State Government, through a reduced dividend payment).

Non-controllable operating costs

All non-controllable operating costs were initially identified as relating to generation activities. This is because the purchase of electricity from IPPs through PPAs and the purchase of fuel for its self-generation activities and tolling arrangements with IPPs, dominates Horizon Power's generation operating costs (just over 94 per cent of total generation operating costs) over the review period. Each IPP has its own set of escalation factors written into the contract terms. Consequently, in the short term, Horizon Power has very limited control over these IPP costs and their embedded escalation factors. The non-controllable elements of generation operating costs over the review period are given in Table 7.2 below. For comparative purposes all costs are shown in prices as at 30 June 2009, having been deflated by CPI. It should be noted that the embedded inflation factors in IPP contracts may differ from CPI.

Table 7.2 Forecast generation operating costs analysis ($m real at 30/6/2009)

Generation operating cost item	Total 2009/10 to 2013/14	Percent of total generation operating costs
Distillate/Waste Oil	27.0	2.5
Gas transport/Gas purchase	160.5	15.1
Electricity purchase (capacity and energy)	773.9	72.8
Renewable energy (capacity and energy)	41.9	3.9
Sub-total non-controllable generation operating costs	**1003.4**	**94.4**

Source: Horizon Power town reports at 8 Sep 2010 and ERA analysis

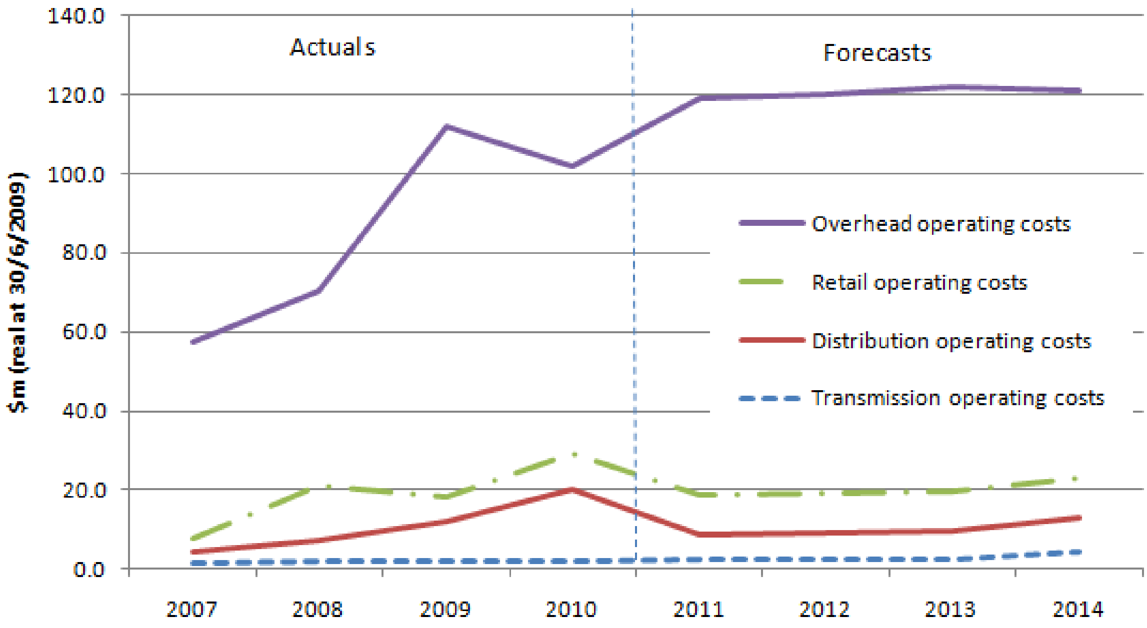
With the above generating operating cost items removed, Horizon Power's remaining operating costs are considered 'controllable'. This amounts to a total controllable operating cost of $584.2m (real as at 30/6/2009) for the review period (or an average controllable operating cost of $116.8m per annum).

In the draft report the Authority recognised the fixed nature of the majority (94.4 per cent) of Horizon Power's generation operating costs and did not apply any efficiency factor to the 'non-controllable' element and retained the escalation factors inherent in the PPAs in financial modelling.

Controllable operating costs

Some of Horizon Power's generation operating costs are considered controllable in the short term, such as the operating expenditure associated with the maintenance of its own power stations. However, these are very small (just 5.6 per cent of total generation operating costs) compared to non-controllable generation costs (94.4 per cent of total generation operating costs). Therefore, controllable generation operating costs are not shown in Figure 7.3 below but are commented on in the section below on generation operating costs.

Figure 7.3 Actual and forecast controllable operating costs ($m real at 30/6/2009)



Source: Horizon Power town reports at 16 Sep 2010 and ERA analysis

Generation operating costs

As is explained above, in the short term, the majority of Horizon Power's generation operating costs are fixed because they are defined by the contractual terms of individual PPAs. However, Horizon Power has scope to affect contract costs when PPAs are renegotiated.

As part of its technical review PB was asked to investigate the efficiency of Horizon Power's procurement processes, which include PPA tenders. PB observed that as PPAs expire and are replaced, Horizon Power has improved the terms of its PPA contracts and has looked to drive down costs where possible.[85] PB expressed concerns that, despite a competitive tendering approach, in remote areas there is a lack of competition for outsourcing services, as often there is only a single electricity supplier in remote areas.

Horizon Power informed PB that, in response to the lack of IPPs in remote regions, it has chosen to bring some services in-house where there is a proven financial case to do so. This has enabled Horizon Power to form comparisons of its own cost to supply with those of IPPs. Horizon Power generates its own electricity on nine sites, as shown in Table 7.3 below.

[85] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 7.4, pp 75

Table 7.3 Horizon Power self-generation locations

Location	Fuel type	Approximate installed capacity MW
Carnarvon	Gas/diesel	16.5
Coral Bay	Diesel	2.24
	Wind (IPP)	*0.825*
Denham	Diesel	2.55
	Wind (IPP)	*1.02*
Hopetoun	Diesel	2.24
	Wind (IPP)	*1.2*
Kununurra	Standby diesel plant	12.4
	Hydro (IPP)	*30*
Marble bar	Diesel	1.276
	Solar	0.3
Nullagine	Diesel	0.96
	Solar	0.2
Onslow	Standby diesel plant	2.8
	Gas (IPP)	*3.42*
Wyndham	Standby diesel plant	2.0
	Hydro (IPP)	*As per Kununurra above*

Source: Email and attachment from Horizon Power, 15/10/2010

PB investigated the operating cost expenditure for Horizon Power's self-generation and although it observed considerable cost overruns and underruns with regard to fuel purchases and maintenance, these are mostly explained by:

- fuel costs being linked to the generation output, which is variable given that much of the diesel generation in remote locations is used to back up peak demand; and
- the age of mobile plant where emergency or reactive maintenance surpasses any planned or corrective maintenance.

Consequently, PB did not make any specific recommendations regarding generation operating costs.

Transmission operating costs

After removing any assumed inflation, Horizon Power incurred annual average transmission operating costs of $1.8m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) transmission operating costs of $2.7m (real at 30/6/09) over the review period. This is an increase of 50 per cent in the average annual expenditure between 2006/07 to 2008/09 and 2009/10 to 2013/14.

Transmission operating costs follow a similar profile to that of historic expenditure, ranging between $1.8m and $2.6m per annum. The exception is an increase of $1.7m (real as at 30/6/2009) in 2013/14. These are operations and maintenance expenditures associated with the commissioning of the proposed new power station in South Hedland. Horizon Power informed PB that as Horizon Power currently has no generation operation and maintenance cost codes for the Pilbara, it has temporarily classified these costs as transmission related.[86]

PB did not make any specific recommendations regarding transmission operating costs.

Distribution operating costs

After removing assumed cost escalation, Horizon Power incurred annual average distribution operating costs of $6.1m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) distribution operating costs of $9.4m (real at 30/6/09) over the review period. This is an increase of 54.1 per cent in the average annual expenditure between 2006/07 to 2008/09 and 2009/10 to 2013/14.

The spike in operating costs in 2009/10 is due to an increase in the following costs:

- maintenance costs (contractors and consultants) of $6.4m nominal;
- overhead recovery of $6.0m nominal; and
- CSO expense of $6.2m nominal.

CSO expense was removed from the 2009/10 base year (and all other years) for financial modelling purposes in the draft report because the cost of service model excludes any sources of external funding arrangements for Horizon Power for the calculation of the revenue requirement and cost-reflective tariffs.

PB did not make any specific recommendations regarding distribution operating costs.

Retail operating costs

Retail operating costs are associated with metering and billing services, customer services and marketing and product development. Horizon Power contracts out its metering, billing and customer service functions through competitively tendered Service Level Agreements (SLAs) as follows:

- meter reading – AMRS Pty Ltd;
- data management – Western Power; and
- billing and customer contact – Serviceworks Ltd.

After removing assumed escalation, Horizon Power incurred annual average retail operating costs of $7.9m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) retail operating costs of $9.9m (real at 30/6/09) over the review period. This is an increase of 25.3 per cent in the average annual expenditure between 2006/07 to 2008/09 and 2009/10 to 2013/14.

There is a large expenditure of $11.7m (nominal) in 2007/08 on ‘other’ metering and billing costs. Horizon Power advised the Authority that this is mainly related to incorrect coding of the costs in its accounting system in a previous year.[87]

[86] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 8.3, p82

[87] Horizon Power (2010), email dated 18 November 2010. CSO expense costs which, because of a change in Horizon Power’s chart of accounts, had been incorrectly captured in this accounts code in 2007/08.

The Authority did not determine a separate retail margin for Horizon Power in the draft report because the systematic risks faced by Horizon Power as a vertically integrated electricity supplier are accounted for in the calculation of its return on capital. This also ensures an appropriate return on any retail assets Horizon Power owns, which are minimal.

PB did not make any specific recommendations regarding retail operating costs.

Corporate and district overhead operating costs

After removing assumed escalation, Horizon Power incurred annual average overhead operating costs of $64.2m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) overhead operating costs of $94.9m (real at 30/6/09) over the review period. This is an increase of 47.8 per cent in the average annual expenditure between the two periods.

In real terms, overheads contributed 27 per cent to total operating costs over 2006/07 to 2008/09 and are forecast to contribute 28.8 per cent to total operating costs over 2009/10 to 2013/14. This is partly explained by Horizon Power's practice of forecasting operating costs at the district and corporate level with the consequence that a disproportionate level of cost is held at this level and not directly allocated to the respective towns.

In its report, PB expressed some concern that Horizon Power appears to have inherited or adopted processes and an organisational structure from a model of the larger legacy business (WPC), which contributed to a 'top heavy' organisational structure and cost loading. In its submission on the draft report, Horizon Power commented that given its vertically integrated structure[88] it is subject to a greater regulatory burden which in itself contributes to its organisational structure through increased numbers of staff engaged in monitoring and compliance activities.[89]

PB also commented on increasing staff levels from inception (193 full-time equivalents) to the current time (388 full-time equivalents) and noted that staffing levels are increasing faster than sales, which could suggest that additional personnel are working in a centralised support function.[90]

Three main areas of costs are driving 40.9 per cent of total overheads, these are:

- labour 22.1 per cent ($104.8m real at 30/6/2009);
- IT services 9.7 per cent ($46.1m real at 30/6/2009); and
- strategic management 9.1 per cent ($43m real at 30/6/2009).

The additional layer of district overhead resulting from the adoption of a decentralised operating model increases the amount of overheads as a proportion of overall operating costs. At the Authority's request PB was asked to investigate this further. In response, Horizon Power prepared a breakdown of overheads, differentiating the traditional overhead items such at IT, finance and people services, from district level overheads.

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88 A vertically integrated structure is such that Horizon Power is responsible for the entire electricity supply process, from generation, through transmission and distribution to retailing to customers.

89 Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, Schedule B, response reference number 26

90 Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 8.8, p87

Historically, Horizon Power's traditional corporate overheads varied from 13 per cent (in 2007/08) to 22 per cent (in 2006/07) as a percentage of total operating expenditure. PB then benchmarked this percentage range of overheads against a number of electricity, gas and water companies. Corporate overheads as a percentage of total operating costs ranged from 15 to 25 per cent for these companies. Horizon Power's overhead proportion falls towards the high end of this range.[91]

PB subsequently concluded that, although towards the upper end of the benchmarked range, Horizon Power's level of corporate overhead operating costs was not unusual and so did not recommend any specific reduction to Horizon Power's forecast.

Renewable energy costs

The Terms of Reference request that the Authority take into account:

- "the efficient costs related to the Mandatory Renewable Energy Target (**MRET**), including the expanded MRET, if applicable; and
- the efficient costs related to the proposed Carbon Pollution Reduction Scheme (**CPRS**), including the carbon intensity that should be applied in determining CPRS costs that would be incorporated into the cost-reflective retail tariffs."

PB reviewed the impact of RET[92] and CPRS on Horizon Power's budget forecasts as part of its review.[93] Horizon Power advised PB that, after the Federal Government's statement[94] in April 2010 that the start of the CPRS would be delayed until early 2013 and on direction from the Department of Treasury and Finance it removed the cost of carbon from its budget forecasts.

Horizon Power advised that it has assessed the impact of the Renewable Energy Target on the organisation and has committed to a key performance indicator on reducing the carbon intensity of its operations.[95]

Horizon Power advised that its current Renewable Energy Certificate (REC) liability is around 30,000 certificates and it has a contract in place which will cover half of this requirement through to 2012. Horizon Power intends to purchase the shortfall on the market. With a current market price of around $35 per certificate, this results in a REC-related expenditure for Horizon Power of around $1.2m (nominal) per year. This forecast was included in the generation operating costs for the NWIS.

The Federal Government has recently announced that it will be introducing a carbon price from 1 July 2012.[96] However, as the amount of the carbon price is unlikely to be known until the 2012/13 financial year the Authority has been unable to model the effect of the carbon pricing on cost-reflective tariffs for this inquiry.

[91] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.3.5, p48

[92] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, Schedule B, response reference number 47. Horizon Power advises that MRET is now referred to simply as RET.

[93] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 5.4.3, p51

[94] Department of Climate Change and Energy Efficiency website, http://www.climatechange.gov.au/whats-new/cprs-delayed.aspx

[95] Horizon Power (2010), Fact Sheet No. 12 – CPRS & RET Liabilities – Forecasting, Considerations and Allowances

[96] Prime Minister (2011), Media release – Climate Change Framework Announced, 28 February 2011

7.2 Operating cost issues

The Authority identified three main issues relating to Horizon Power's operating costs over the review period, these are:

- application of an efficiency target to Horizon Power's controllable unit cost;
- selection of 2009/10 as the base year against which to apply the efficiency target; and
- the exclusion of 'inefficient' operating costs.

Each of these issues was discussed in the draft report and a recommendation made on how these issues should be treated.

Public submissions have been received on each issue and the Authority has proposed a recommendation for each issue in the final report. Commentary on each of the issues and the Authority's final recommendation are discussed separately below.

7.2.1 Application of an efficiency target

In the draft report the Authority recommended an efficiency target for Horizon Power's operating cost forecasts. The reasons for this are explained in more detail below.

Only a proportion of Horizon Power's operating cost are controllable in the short-term (35.5 per cent) so any efficiency gains should focus on Horizon Power's controllable operating costs. The problem with applying an efficiency target to controllable operating costs is the possibility that the proposed reductions to controllable operating costs from the efficiency target are offset by increases in costs resulting from increased demand for electricity. Increased demand can result from:

- the number of customer connections increasing, as more customers connect to a network;
- increases in electricity consumption per connection; or
- both of the above.

An alternative to presenting controllable operating cost data in total is to show unit operating costs per kWh or per connection. This removes the effect of growth in energy demanded or numbers of connections on operating costs which aids understanding of the real trends in costs over time. Unit controllable operating cost data is shown in Table 7.4 below.

Table 7.4 Unit controllable operating costs based on Horizon Power's unescalated operating cost forecasts (real at 30/6/09)

Unit controllable operating cost	2010	2011	2012	2013	2014
$ per kWh	0.113	0.122	0.123	0.127	0.127
$ per connection	2,574	2,943	3,019	3,148	3,177

Source: ERA analysis

Over the five year review period unit controllable operating costs initially increase from 2009/10 to 2010/11 then reduce each year. Overall unit controllable operating costs per kWh reduce by three per cent over the review period and unit operating cost per connection increase by six per cent over the review period.

In its report, PB noted that:

> "..PB would expect that eventually increases in opex should cease and then start to decrease as the company realises efficiencies. A company operating in a competitive environment would be expected to achieve reductions in opex. PB is therefore concerned that in real terms the company is still forecasting an average 3% increase in opex per annum over the next four years."[97]

As a relevant case study, PB referenced the experience of Victorian electricity distribution businesses[98] since they were privatised. PB reported that, in the first year of the second regulatory period, companies were set operating efficiency targets of between 3.1 per cent and 16.4 per cent, followed by an average operating cost efficiency target of 1.2 per cent in each subsequent year. PB calculated that, overall, this represented an annual average reduction of three per cent.

Consequently, PB recommended in its report that the experience of the Victorian electricity distributors could be used as a benchmark for setting an efficiency target to reduce Horizon Power's real controllable operating costs by three per cent per annum. In effect, this would hold Horizon Power's controllable operating costs constant in real terms between 2010/11 and 2012/13.

In the draft report the Authority modelled the effect of PB's three per cent efficiency recommendation on Horizon Power's unit controllable operating costs, as shown in Table 7.5 below. Despite the three per cent reduction to overall controllable operating costs, the result is an increase in controllable unit costs of 2.5 per cent per annum.

Table 7.5 Comparison of unescalated controllable unit operating costs for Horizon Power against PB's recommendations (real at 30/6/2009)

Unit controllable operating cost ($ per connection)	2010	2011	2012	2013	2014
Horizon Power proposed	2,572	2,922	2,862	2,828	2,736
Percentage change per annum		13.6%	-2.1%	-1.2%	-3.3%
PB's recommendation	2,572	2,637	2,702	2,770	2,839
Percentage change per annum		2.5%	2.5%	2.5%	2.5%

Source: ERA analysis

In determining Horizon Power's level of efficient controllable operating costs, the Authority first reviewed PB's recommendation regarding global efficiency savings and recalculated this to show the effect upon unit controllable operating costs. From this analysis the Authority considered that the reductions recommended by PB did not sufficiently challenge Horizon Power to operate efficiently.

The Authority reviewed PB's report and Horizon Power's actual and forecast operating cost data and concluded that, whilst recognising the period of adjustment Horizon Power has experienced following disaggregation, there is scope for efficiency savings in Horizon Power's controllable operating costs over the review period.

The Authority noted PB's proposed three per cent reduction to controllable operating costs. However in the draft report, the Authority considered that the unit operating cost

[97] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 8.8, p89

[98] AGL, CitiPower, Powercor, TXU/SP AusNet and United Energy

per kWh or per connection should decrease (in real terms) as the company becomes more efficient, not increase as suggested by PB. The application of an efficiency target to unit controllable operating costs removes the impact of increased costs resulting from growth in demand and was the approach followed by the Authority when it recommended efficiency targets for the Water Corporation.[99]

The following observations support the application of efficiency savings on controllable unit operating costs:

- the high level of corporate overheads as a proportion of controllable operating costs (28.8 per cent is at the top end of the benchmarking range established by PB);
- PB's observation that Horizon Power has adopted processes and an organisational structure from a model of a larger legacy business, which contributed to the apparent 'top heavy' nature of Horizon Power's organisation;
- the operation of two district offices in the Pilbara (West Pilbara district office in Karratha and East Pilbara district office in Port Hedland). Both of these offices are involved in running the NWIS, which is operated as a single system; consequently, there is scope to reduce the two district offices to one;
- PB's recommendation of an annual three per cent reduction in controllable forecast operating costs; and
- Horizon Power is not subject to competitive pressure from the market, as is the case for the Victorian electricity distributors.

The Authority's draft recommendation on this issue is shown below.

An efficiency target of one per cent compounded per annum be applied to the 2009/10 level of controllable unit operating costs per connection.

7.2.2 Public submissions on the draft report

Three of the submissions received in response to the draft report commented on the use of a one per cent efficiency target applied to Horizon Power's controllable unit costs per connection (Horizon Power, Western Power and the Office of Energy). All of these submissions are published on the Authority's website.[100]

Horizon Power submission

Horizon Power expresses three main concerns in its submission regarding this draft recommendation, these are:

- the selection of 2009/10 as the base year from which to apply an efficiency target;
- the 'de-linking' of operating costs from Horizon Power's asset management and budgeting processes; and
- the selection of a one per cent compounding efficiency target on controllable unit costs per connection.

Horizon Power argues that as young business it will continue to grow until 2012/13 at which point it will enter its 'consolidation' stage and start to achieve real efficiency savings.

[99] ERA (2009), Inquiry into Tariffs of the Water Corporation, Aqwest and Busselton Water

[100] Economic Regulation Authority website www.erawa.com.au

These have been estimated by Horizon Power as savings of 5.6 per cent to 2015/16. Furthermore, by de-linking operating cost expenditure from the asset management planning process, Horizon Power believes the approach the Authority recommended in the draft report does not sufficiently:

> "..reflect the requirements (compliance, safety and regulatory, capacity, reliability, quality and asset service) within the business's Asset Management Plan.."[101]

Horizon Power's submission was particularly critical of the application of a one per cent efficiency target to controllable unit operating costs per connection. The selection of the one per cent efficiency target was 'highly arbitrary' and the Authority's benchmarking of operating costs 'informal' and 'judgemental'.[102]

Horizon Power contends that the cost per connection approach 'fails to take account of the small system size and volatility of connection numbers' and that a per connection approach is 'only appropriate for companies with large homogenous customer bases'. Horizon Power gives an example of the addition of a new customer, such as a new resort marina requiring 5GWh, to a community such as Exmouth where this one additional customer would represent 20 per cent of the total load of the system. This in turn would require an upgrade to the generation and distribution infrastructure and so significantly change the overall cost of supply in Exmouth.

The selection of a one per cent efficiency target was queried by Horizon Power on the grounds that:

- adoption of a similar approach to that used for Water Corporation is inappropriate as Water Corporation is not a relevant benchmark for Horizon Power;
- the Power and Water study was outdated; and
- operating costs only appear to be a significant driver of cost of service for Horizon Power as the Authority's proposed initial capital base is too low.

Other submissions

Western Power's submission comments that it:

> "..does not agree that the proposed use of an efficiency target is appropriate and suggests that the ERA further assess the development of an incentive mechanism similar to the GSM (gain-sharing mechanism)."[103]

Furthermore, Western Power suggests that the analysis undertaken by PB is 'overly simplistic and misleading' as operating costs for the same Victorian distribution network businesses rose in real terms in the following regulatory period. In addition, Western Power notes that the Authority has failed to take into account other considerations such as the 'specific circumstances of a small, geographically dispersed business, that Horizon Power undertakes 'good practice in the monitoring the appropriate level of management structure required in its districts' and of 'new and revised processes, systems and methodologies recently embedded in the business'. Western Power concludes that the

[101] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, p25

[102] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, p28

[103] Western Power (2011), Submission to draft report on Horizon Power's funding arrangements, pp 2-3. GSM refers to Gain-sharing Mechanism.

proposed efficiency target would not be effective in achieving the objective of balancing benefits to customers and the service provider.

The Office of Energy's submission suggests that:

> "..it may be most appropriate that any efficiency target in this first period is conservative" and that the Authority should "very carefully reconsider its recommendation."[104]

The one per cent efficiency target is considered 'arbitrary' and 'very ambitious' and could be unreasonably onerous if the base costs or reduction amount is inappropriate. In line with Western Power's comments, the Office of Energy also noted that the efficiency target 'fails to recognise any increased efficiencies built into Horizon's numbers'.

7.2.3 Authority comments

In the draft report, the Authority took the 2009/10 base year controllable operating costs of $102.0m (real at 30/6/2009) and applied a compounding reduction in the unit operating cost per connection of one per cent per annum for each year of the review period.

The determination of the one per cent efficiency target is supported by:

- a similar approach taken for the Water Corporation in previous inquiries, where the Authority applied a reduction in base real operating expenditure per connection of 1.88 per cent per year;
- a similar operating cost efficiency factor of 10 per cent over a 10 year period recommended for Power and Water in its 2009 Network Pricing Reset;[105] and
- the emergence of operating costs as a clear focus for an efficiency target as they are the predominant driver of the total cost of service for Horizon Power (see section 10).

The Authority is comfortable with the approach of applying an efficiency target to unit controllable operating costs per connection on the basis that, over time, an efficient service provider should be able to reduce its unit costs of supply for a given level of service.

This does not necessarily imply that unit costs only decrease as the numbers of connections grow, as Horizon Power suggests in its submission. Instead unit costs decrease as a service provider becomes more efficient in its service delivery. If Horizon Power is committed to delivering operating efficiencies, as it claims, then these should be able to be translated into a reduced cost per connection over time. Furthermore, where the addition of a new customer, such as in the Exmouth example provided by Horizon Power above, may affect the cost of service in an individual system, the controllable unit cost per connection is calculated at the aggregate level and will be tempered by reductions in unit costs in systems were customer numbers are stable. In addition, the majority of the costs associated with increasing the distribution infrastructure will be capital costs. Depending on whether Horizon Power decides to build own and operate any additional generation capacity or outsource to an IPP these costs will again be either capitalised in the case of bringing generation in-house or excluded from the controllable unit cost per connection calculation if the generation costs are outsourced to an IPP.

[104] Office of Energy (2011), Office of Energy's submission on the draft report for the inquiry into the funding arrangements of Horizon Power, Attachment 1, p2

[105] Meyrick and Associates (2008), Electricity Distribution X Factors for the NT's Third Regulatory Period, piii

The effect of applying a one per cent compounded reduction to the Authority's revised recommended controllable unit operating costs is shown in Table 7.6 below.

Table 7.6 Final report − comparison of controllable unit operating costs (real at 30/6/2009)

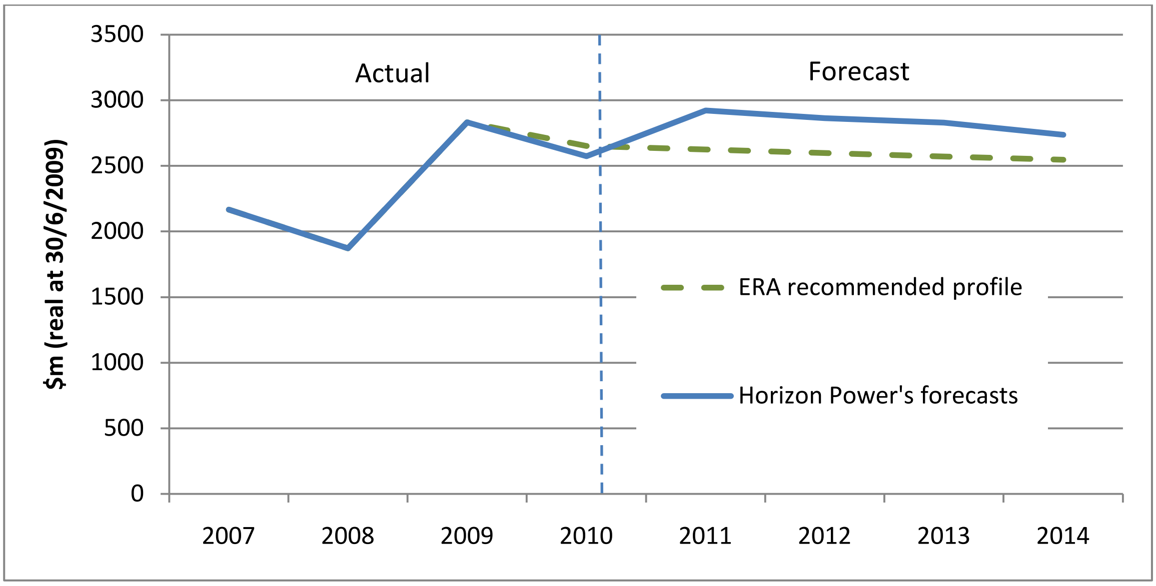
Unit controllable operating cost ($ per connection)	2010	2011	2012	2013	2014
Horizon Power original proposal	2,572	2,922	2,862	2,828	2,736
Percentage change per annum		*13.6%*	*-2.1%*	*-1.2%*	*-3.3%*
ERA final report recommendation	**2,652**	**2,624**	**2,597**	**2,571**	**2,546**
Percentage change per annum		*-1%*	*-1%*	*-1%*	*-1%*

Source: Horizon Power information submitted 28 February to 4 March 2011 and ERA analysis.

The slightly higher unit operating cost in 2009/10 assumed by the Authority compared to Horizon Power's original 2009/10 unit cost results from the request by Horizon Power to have additional operating cost items added into the base year. This is explained in more detail in section 7.12.2 below.

The effect of the efficiency target on controllable unit operating costs is shown in Figure 7.4 below.

Figure 7.4 Final report − trends in controllable unit costs per connection based on Horizon Power's forecasts and ERA's revised recommendations ($m real at 30/6/2009)



Source: ERA analysis

The Authority acknowledges the inherent difficulties in benchmarking a company such as Horizon Power. However, this does not suggest that benchmarking should not be attempted. The reference to earlier Water Corporation inquiries supports the mechanism of using unit cost per connection to drive efficiencies through a vertically integrated service provider. The Authority also notes that use of a previous benchmarking exercise undertaken for Power and Water also considers a vertically integrated service provider and although the original benchmarking exercise was undertaken in 2003, this information was updated in 2009 and it was this data that was used by the Authority in suggesting the one per cent efficiency target.

Whilst the Authority notes Western Power's suggestion that an incentive mechanism should be developed for Horizon Power, it remains of the opinion that whilst customer tariffs are subsidised it is inappropriate to introduce a gain-sharing mechanism to deliver further reductions to already subsidised tariffs.

Horizon Power's argument that the ICB value used by the Authority is too low and this artificially increases the influence of operating costs on the cost of service is considered by the Authority in section 6.3 above.

After consideration of the submissions commenting on this issue, the Authority has slightly amended its draft recommendation to include the option of applying the one per cent efficiency target to an adjusted level of controllable operating costs in 2009/10. The adjustment to the 2009/10 base year level of controllable operating costs is to take account of the additional operating costs requested by Horizon Power following the draft report. The extent of the adjustment is explained in section 7.7.4 below. The revised final recommendation is shown below.

7.7.1 Final recommendation

4) An efficiency target of one per cent compounded per annum be applied to Horizon Power's adjusted 2009/10 level of controllable unit costs per connection for the duration of the review period.

7.7.2 Selection of 2009/10 as a base year against which to apply an efficiency target

The base year of 2009/10 was selected on which to apply an operating cost efficiency target because it is the latest year for which actual operating costs were available and for which costs had been allocated across each town, distribution system and cost function.

Information on 2009/10 operating costs was initially selected from the individual town reports submitted to the Authority on 16 September 2010. The operating expenditure in 2009/10 was adjusted by the Authority to remove certain items (CSO expense, depreciation, interest and amortisation) before being used as a base year for efficiency purposes in the draft report.

In taking this approach the Authority was aware that the application of an efficiency target to controllable unit cost operating expenditure in 2009/10 did not take account of any specific operational projects or programmes that Horizon Power may have included in its submitted operating cost forecasts.

Therefore, in the draft report the Authority stated that Horizon Power could request, in its response to the draft report, that additional operating costs for new or existing projects or programmes be considered by the Authority. The Authority would then review each request on a case-by-case basis and include any additions to the efficient level of operating expenditure in the final report. However, Horizon Power would need to demonstrate that the expenditure is efficient and could not be met from base operating expenditure.

The Authority's draft recommendation on this issue is shown below.

Horizon Power submit, in response to the draft report, individual business cases for any additional operating expenditure requests over and above the recommended profile as outlined in Table 7.8. The Authority will then consider each request on a case by case basis and include any additions to the efficient level of operating costs in the final report.

7.7.3 Public submissions on the draft report

None of the submissions received commented on the inclusion of this recommendation in the draft report. However, Horizon Power did submit business cases for additional operating costs following its submission in response to the draft report. The information contained in these business cases has been modelled by the Authority and is discussed in section 7.7.4 below.

7.7.4 Authority comments

In February and March 2011, Horizon Power submitted 11 business cases to support an additional $25.8m (real at 30/6/2009) of operating costs to be added to Authority's recommended operating cost forecast for the inquiry. The business cases submitted covered a wide variety of expenditure that Horizon Power maintains is either:

- non-controllable over some or all of the review period, e.g. existing service level agreements with Western Power; or
- was included in the 2009/10 budget but has not been realised in the 2009/10 actual costs, e.g. this predominantly relates to employment vacancies that were filled only part way through the 2009/10 financial year; or
- relates to capital projects that have been included in the forecast capital expenditure over the review period.

The additional operating expenditure requested by Horizon Power is summarised in Table 7.7 below.

Table 7.7 Additional operating expenditure allowed by the Authority ($m real at 30/6/2009)

Item	2010	2011	2012	2013	2014	Total
Non-controllable	1.6	4.3	4.0	2.7	2.6	15.2
Controllable	2.7	0	0	0	0	2.7
Total	4.3	4.3	4.0	2.7	2.6	17.9

Source: Horizon Power additional information submitted February and March 2011 and ERA analysis. Totals may not add due to rounding.

The Authority has analysed the business cases and suggests that, of the $25.8m (real at 30/6/2009) additional operating costs submitted by Horizon Power, $2.7m (real at 30/6/2009) should be included in the 2009/10 base year controllable operating cost figure and $15.2m (real at 30/6/2009) should be included as non-controllable operating costs over the review period. An analysis of the submitted business cases and the suggested operating costs included in the Authority's recommended operating cost profile is given in Appendix I.

Table 7.8 below restates the Authority's suggested controllable base year operating costs for Horizon Power. This figure includes the effect of allowing escalation of operating costs by forecast BCI as outlined in section 3.3.2 above.

Table 7.8 Final report − derivation of adjusted 2009/10 controllable operating costs ($m real at 30/6/2009)

Item	Adjusted 2009/10
Initial aggregate operating cost	338.7
Less deductions as per Table 7.6	-61.8
Base year total operating costs	277.0
Less non-controllable generation costs	-175.0
Base year controllable operating costs (draft report)	102.0
Plus additional controllable operating costs	+2.7
Adjusted base year controllable operating costs	104.8
Adjusted base year controllable operating costs with additional escalation	**105.2**

Source: Horizon Power information submitted 28 February to 4 March 2011 and ERA analysis. Totals may not add due to rounding.

Allowing for additional operating costs to be added to the base year has recognised expenditure that Horizon Power is committed to in order to reach a point in its evolution where it can begin to consolidate and achieve efficiencies. The Authority suggests that this approach addresses the concern expressed by the Office of Energy in its submission that the efficiency target could be unduly onerous if the base position is inappropriate. Adding back specific operating expenditure will improve the appropriateness of the base position.

The compounded one per cent efficiency factor is then applied to adjusted 2009/10 base year controllable unit operating costs per connection.

The $15.2m (real at 30/6/2009) of additional non-controllable operating costs has been included in the revised total operating cost profile and escalated in line with recommendation 3 from section 3.3 above. This is shown in Table 7.9 below.

By adding non-controllable generation operating costs and non-controllable ‘other’ operating costs back to the controllable operating cost profile demonstrates the impact upon total operating costs, as shown in Table 7.9 below.[106]

Table 7.9 Final report − revised total operating cost profiles ($m real at 30/6/2009)

Total operating costs	2010	2011	2012	2013	2014	Total
Horizon Power proposed	277.0	327.9	332.3	373.3	336.3	1,646.7
ERA recommended (final report)	**281.9**	**317.5**	**322.4**	**325.2**	**327.1**	**1,574.1**
Reduction (from Horizon Power proposed)	+4.9	-10.4	-9.9	-48.1	-9.2	-72.6
As a percentage	*1.7%*	*-3.2%*	*-3.0%*	*-12.9%*	*-2.7%*	*-4.4%*

Source: Horizon Power information submitted 28 February to 4 March 2011 and ERA analysis.

The Authority’s final recommendations on this issue are shown below.

[106] The large reduction in operating costs in 2012/13 relates to the removal of temporary generation costs associated with the delay in the funding approval for the South Hedland power station. This is discussed in more detail in the following section.

Final recommendation five recognises:

- the initial base year efficient operating costs as identified in the draft report ($102.0m (real at 30/6/2009);
- the additional efficient controllable operating costs identified by the Authority for inclusion in the final report; and
- the effect of the additional escalation to operating costs identified in final recommendation one.

Final recommendation six recognises:

- Horizon Power's total efficient non-controllable generation-related operating costs of $1,003.4m (real at 30/6/2009) over the review period; and
- Horizon Power's total efficient non-controllable other operating costs of $26.2m (real at 30/6/2009) over the review period.

7.7.5 Final recommendations

5) The efficient level of Horizon Power's 2009/10 base year adjusted controllable operating costs be $105.2m (real at 30/6/2009).

6) Horizon Power's efficient level of non-controllable operating costs for the review period is $1,029.6m (real at 30/6/2009).

7.7.6 Operating costs resulting from the delay in funding approval for the South Hedland power station

In the draft report, the Authority reviewed the increase in generation operating costs ($35m real at 30/6/2009 in 2012/13) associated with the additional electricity purchased to cover demand whilst the new power station at South Hedland was being built. The Authority noted from Horizon Power that delays in the budget approval process with State Government had contributed to the increased costs. However, the Authority did not consider that this additional cost should be passed on to SWIS customers via the TEC. Instead, this cost should be borne by Horizon Power or its shareholder. In addition, should the commissioning of South Hedland be delayed further, or if the additional electricity costs turned out higher than budgeted, any additional cost should also be borne by Horizon Power or its shareholder. The Authority's draft recommendation in relation to this issue is listed below.

The forecast operating costs incurred as a result of the delay in obtaining funding approval for the South Hedland power station project be borne by Horizon Power. Consequently, the Authority proposes that $35 million (real as at 30/6/2009) be removed from the non-controllable generation operating costs in the NWIS in 2012/13 for the purpose of determining cost-reflective tariffs.

7.7.7 Public submissions on the draft report

The Authority received three submissions that commented on this draft recommendation. These submissions, from Horizon Power, WACOSS and the Office of Energy, are available on the Authority's website.[107]

Horizon Power submission

Horizon Power's submission argues that the Terms of Reference seek to determine efficient costs:

> "..that are prudent and reasonable for the business to operate its portfolio of assets within its current governance, commercial and regulatory environment."[108]

Consequently, Horizon Power suggests that as the costs associated with temporary generation at South Hedland are efficient they should be included within the cost of service calculation.

Horizon Power considers it to be outside the scope of the inquiry for the Authority to comment on the 'effectiveness of the broader mechanisms of Government', or for the Authority not to accept that the process of Government approvals is part of Horizon Power's efficient processes.

Other submissions

In its submission, WACOSS stated that:

> "WACOSS strongly agrees with the Authority that costs due to delays in the budget approval process should not be passed onto residential customers. These costs should be borne by the State Government in the form of a Community Service Obligation (CSO). WACOSS notes that several new generation projects are in the pipeline and suggests that lessons be learnt from project planning and implementation processes to avoid any inefficient cost pass-throughs in the future."[109]

The submission from the Office of Energy is broadly in line with the position taken by WACOSS above. The submission states that:

> "In cases where 'Government Frameworks' have led to cost over-runs, for example the cost over-runs from delays in decisions on the South Hedland power station, the OOE views that Horizon should remain whole and if the Tariff Equalisation Contribution (TEC) will not cover these costs they should be covered by a direct Government subsidy."[110]

7.7.8 Authority comments

The Authority is aware that State Government approval processes are part of Horizon Power's everyday business environment. However, the Authority also suggests that as the sometimes extended nature of the approval process is already known to Horizon Power and State Government then any approval process for new project expenditure

[107] Economic Regulatory Authority website www.erawa.com.au

[108] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, p20

[109] WACOSS (2011), WACOSS submission to the inquiry into the funding arrangements of Horizon Power – Draft report, p4

[110] Office of Energy (2011), Office of Energy's submission on the draft report for the inquiry into the funding arrangements of Horizon Power, Attachment 1, p2

should be started early enough to fully account for the duration of the approvals process and so avoid the additional costs associated with the approval process not adhering to its timetable. As referred to in the draft report[111] Horizon Power advised the Authority that, had the original timeframe been met, then additional energy purchases would not have been required.

The Authority is not suggesting that the Government does not take sufficient time to:

> "..explore all possible options including principal contract extensions and options available to Government within its State Agreements."[112]

However, the Authority would expect that if the process for project approval and funding approval is not adequately factored into the business planning process, and additional costs result, then by their very nature these costs cannot be considered efficient, as they arise from a flawed business planning process. Furthermore, given the funding model that exists for Horizon Power, the Authority is concerned that the inefficient costs that result from a flawed business planning process should not be borne by customers and taxpayers who are subsidising Horizon Power's cost of operations.

The Authority recommendation on this issue is unchanged from the draft report.

7.7.9 Final recommendation

7) The forecast operating costs incurred as a result of the delay in obtaining funding approval for the South Hedland power station project are considered inefficient and as such should be borne by Horizon Power (or its shareholder). Consequently, for the purpose of determining cost-reflective tariffs for the inquiry, the Authority has removed the $35m (real as at 30/6/2009) in inefficient operating costs from the non-controllable generation operating costs in the NWIS in 2012/13.

[111] ERA (2011), Inquiry into the funding arrangements of Horizon Power – Draft Report, p43

[112] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, p21

8 Capital Expenditure

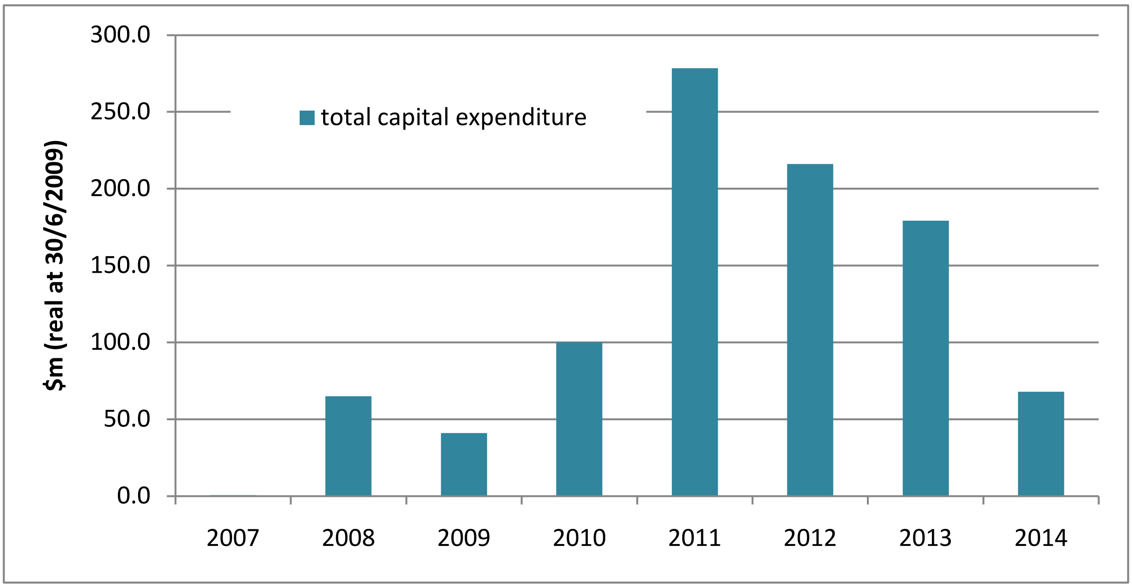
This section reviews Horizon Power's forecast capital expenditures over the review period.

8.1 Background

After removing assumed cost escalation from its original data, Horizon Power incurred annual average capital expenditure costs of $35.5m (real at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) capital expenditure costs of $168.3m (real at 30/6/09) over the period 2009/10 to 2013/14. This is an increase of over 350 per cent in the average annual expenditure between the two periods.

The historical and proposed annual capital expenditure profile from 2006/07 to 2013/14 is shown in Figure 8.1 below.

Figure 8.1 Actual and forecast capital expenditure ($m real at 30/6/09)



Source: Horizon Power spreadsheets[113] and ERA analysis

A comparison of Horizon Power's historical capital spend over the period 2006/07 to 2008/09 with actual and forecast expenditure for the period 2009/10 to 2013/14 shows a significant increase. This is predominately driven by a number of internal generation projects currently underway and planned for the review period.

In 2006, Horizon Power undertook a strategic initiative to review its generation strategy so providing an opportunity to assess its outsourcing strategy and consider alternatives that retains and enhances its existing generation capability, allows economies of scale to be achieved in the future and accesses the lowest cost generation solutions.[114]

This strategy has resulted in Horizon Power building, owning and operating (**BOO**) generation capacity at Marble Bar (commissioned in 2009 and capitalised in 2010) and

[113] Horizon Power (2010), '20100922 – ERA Capex – Unescalated by funding type'

[114] Horizon Power (2006), Submission to the Board of Directors – Generation review: Options for Carnarvon, Nullagine and Marble Bar, p3

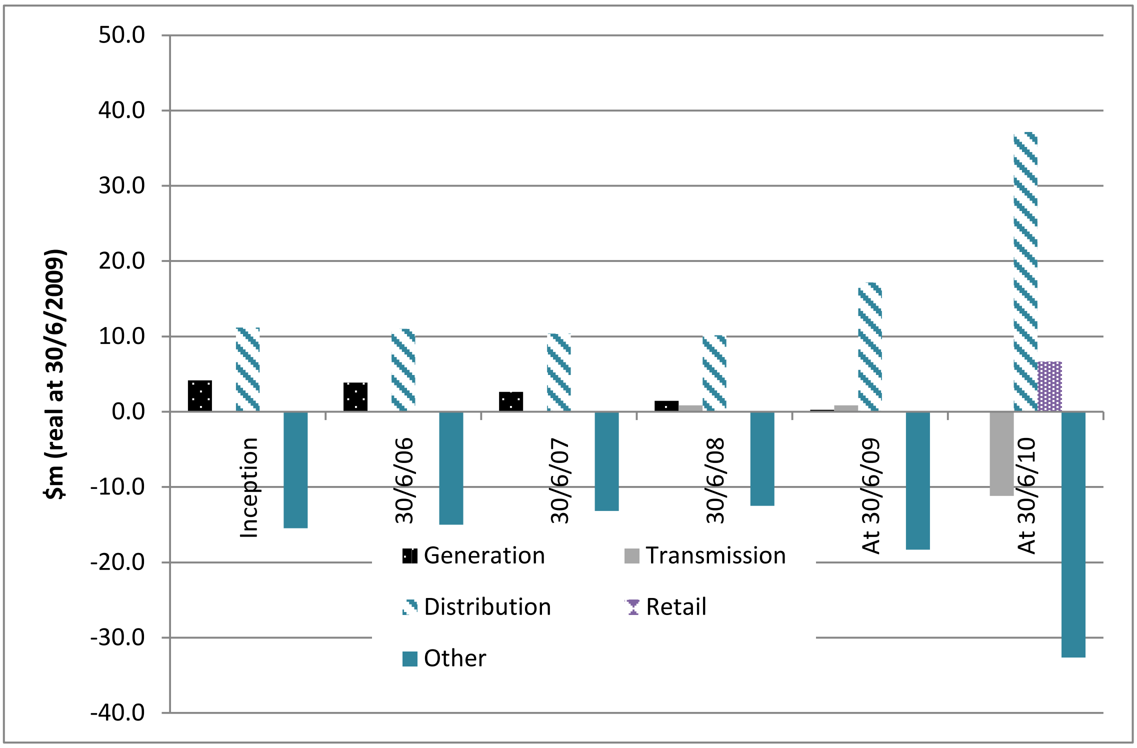
Nullagine (commissioned in 2010 and capitalised in 2011) and has proposed new BOO generators for Carnarvon (under construction) and South Hedland (to be commissioned on 1 July 2013).

This has led to just over half (50.9 per cent) of Horizon Power's forecast capital expenditure programme being driven by generation projects. Dominating these projects is the construction of a new power station at South Hedland to supply electricity into the NWIS ($334.3m at 30/6/2009). More detailed information on the South Hedland generation project is provided below.

Horizon Power owns only minimal retail assets associated with billing and customer care. These services are provided through Service Level Agreements with third parties and, as these are predominantly operating cost items, are discussed in Section 7.

In the draft report, the Authority noted that Horizon Power had reallocated its capital expenditure between functions and asset classes from the first set of capital expenditure and fixed asset register information sent in August 2010 compared to the final set of data received in early November 2010. The effect of this is shown in Figure 8.2 below.

Figure 8.2 Horizon Power's reallocation of assets between functions – final fixed asset register compared to initial fixed asset register



Source: Horizon Power spreadsheets and ERA analysis

The effect of this reallocation was to move the majority of its assets out of the 'other' category and into the 'distribution' category. The result is that no district office capital is dedicated to regional overhead. In particular, the Authority noticed that capital expenditure to refurbish houses was part of this reallocation. Horizon Power informed the Authority that the expenditure on refurbishment was for staff housing and that as most of the staff involved were engaged in distribution related work, this prompted the reallocation.[115]

[115] Horizon Power (2010), email dated 17 November 2010

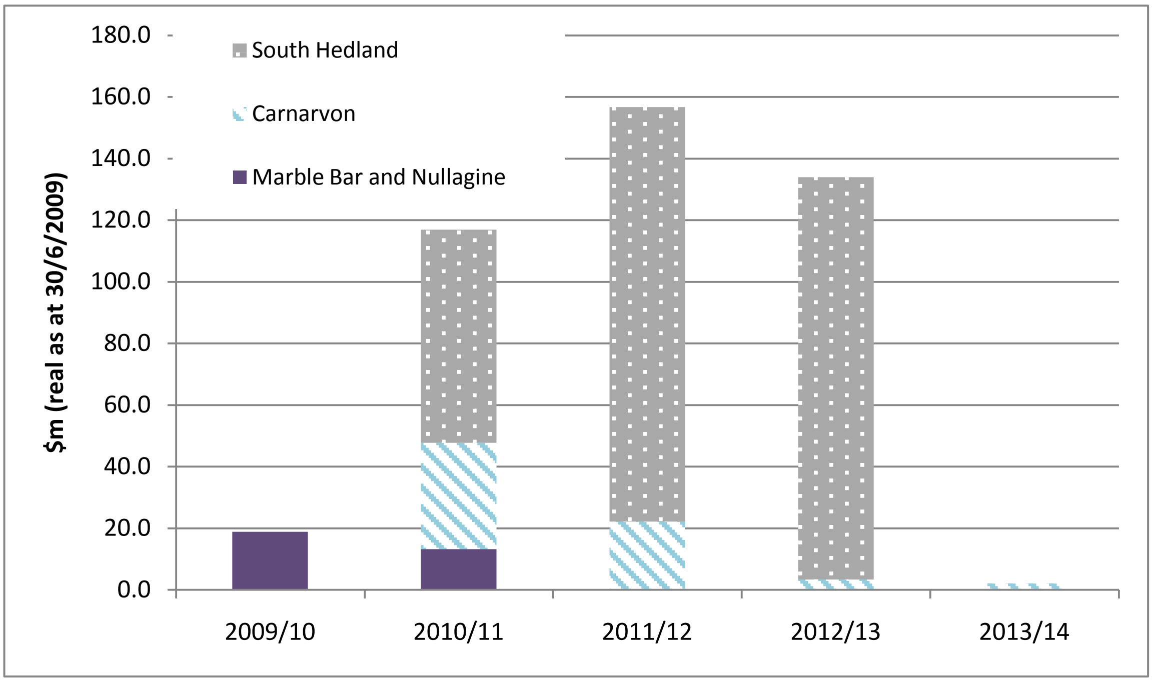
Generation capital costs

By the end of the review period (30 June 2014), Horizon Power will have commissioned four BOO generation projects, assuming all funding approvals are provided. The total capital expenditure on each project, over the five year review period is as follows:

- Marble Bar $20.9m (nominal) - forecast completion cost;
- Nullagine $13m (nominal) - forecast budget cost;
- Carnarvon $62.1m (real at 30/6/2009) - budget cost; and
- South Hedland $334.3m (real at 30/6/2009) - budget cost.

These projects are driving the generation capital expenditure profile shown in Figure 8.3 below.

Figure 8.3 Actual and forecast capital expenditure on key generation projects ($m real at 30/6/09)



Source: Horizon Power spreadsheets[116] and ERA analysis

In determining the optimal generation solution for each system, Horizon Power compared contracting with an IPP to supply electricity with the BOO option. As discussed in section 7 above, prior to disaggregation WPC embarked on a policy to outsource power procurement for remote regional towns (the Remote Towns Power Procurement Process and for Carnarvon, the Carnarvon Power Procurement Process). By 2006, only Marble Bar, Nullagine and Carnarvon remained without IPP arrangements. The generation projects are discussed individually below.

Marble Bar and Nullagine power station projects

Marble Bar and Nullagine are situated inland in the East Pilbara district of Western Australia. Marble Bar is 218km south east of Port Hedland and Nullagine is 195km north

[116] Horizon Power (2010), '20100922 – ERA Capex – Unescalated by funding type'

of Newman. The numbers of premises in each town are 124 and 52 respectively. Existing generators on both sites were at the end of their economic life by 2006 and were supplemented by mobile generation units to provide a reliable electricity supply.

Horizon Power's analysis of the IPP and BOO options (diesel only and diesel/solar combined) for these projects illustrated that the decision to select a solar/diesel option over diesel only was marginal in cost terms. The Authority sighted this information, prior to publication of the draft report but as the information is considered commercial in confidence it was not included in detail in the draft report.

The Post Implementation Review[117] conducted in June 2010 noted that, whilst the new power station delivered the required level of service for Marble Bar and is expected to provide the anticipated reductions in diesel fuel consumed, the project was executed directly from a preliminary business case status, overran by six months and considerably exceeded budgeted costs. PB's investigation confirmed that the generation projects undertaken at Marble Bar and Nullagine went from the prefeasibility stage to the implementation stage, which is in conflict with Horizon Power's own project gating framework.[118]

PB discussed the cost overruns in past generation projects with Horizon Power as part of its investigation. PB was aware that Horizon Power was concerned about the cost management issues with Marble Bar and Nullagine and has taken action to limit the possibility of similar problems happening with future projects.

The outturn costs of each project compared to the budget estimates are given in Table 8.1 below. These figures have been updated from those shown in the draft report for the inquiry. Horizon Power received partial funding of $4.880m (nominal) from the Commonwealth's Renewable Remote Power Generation Programme.[119]

Table 8.1 Comparison of the actual spend and budgeted spend for Marble Bar and Nullagine power station projects ($m nominal)

Project	Budget	Outturn	Variance	Variance (%)
Marble Bar power station *(costs capitalised 2009/10)*	14.685	20.897	6.212	+42.3
Nullagine power station *(costs capitalised 2010/11)*	12.991	n/a	n/a	n/a
Total	27.676	n/a	n/a	n/a
Less Federal funding		-4.880	n/a	n/a

Source: LogiCamms, Post Project Implementation Review, Section 1.6.3, p9

At the time the draft report was published, the Authority was aware of the anticipated outturn cost of the Nullagine power station project. However, some cost discussions between Horizon Power and its suppliers were still continuing and the anticipated outturn cost was considered commercial in confidence until the discussions are resolved.

[117] LogiCamms Ltd. (2010) – Horizon Power hybrid power station – Marble Bar post implementation review

[118] Parsons Brinkerhoff (2010_, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 7.3.1, p68

[119] Ministerial Media Statements - Minister for Energy, Training and Workforce Development (2010) – Boost for renewable energy in regional WA

The Authority requested permission from Horizon Power to publish the outturn costs for Nullagine power station in the final report. Horizon Power responded that Nullagine outturn costs were 'yet to be settled and still the subject of ongoing discussions with suppliers'[120] and requested that outturn cost for Nullagine continue to be excluded from the final report on the grounds that these remain commercial in confidence until finalised. The Authority has complied with this request in the final report but has viewed the expected outturn costs for Nullagine power station and suggests these will result in a variation from budgeted costs of around a similar order of magnitude as are reported for Marble Bar power station in Table 8.1 above.

The Authority was aware that any additional outturn costs of these generation projects over and above the budgeted amounts would ultimately be funded via the TEC and would potentially impact upon the tariffs paid by customers in the SWIS. In response, the Authority considered that SWIS customers should not be unduly penalised for Horizon Power's chosen strategic direction or poor project and cost management.

In the draft report, the Authority was concerned that the decision to bring some generation in-house, or the particular form of the generation chosen, may not be the optimal business model for Horizon Power to adopt. The Authority was particularly concerned that this decision may result in cost overruns, incurred as a result of Horizon Power's inexperience in the self-generation area, and the novel nature of projects (such as the Marble Bar and Nullagine solar generation projects) compared with the standard diesel-only alternatives.

The Authority calculated that the average capital cost per property connection, based on the budget figures for the solar/diesel generation projects, is $118,427 per property for Marble Bar and $249,827 per property for Nullagine. The outturn cost per property for Marble Bar is $168,524 with an even higher anticipated outturn figure per property for Nullagine.

In the preparation of the draft report the Authority noted Horizon Power's recognition of the problems with Marble Bar and Nullagine and the steps it has taken to address these in later generation projects. However, had the comparison of generation options been conducted on more reliable cost estimates (as is required by Horizon Power's own project gating framework) then, in purely cost terms, this may have favoured the IPP option over Horizon Power's decision to bring some generation in-house.

Consequently in the draft report, the Authority recommended reducing actual and forecast capital expenditure by the amount of the cost overrun at Marble Bar and anticipated cost overrun at Nullagine. Therefore the project costs for Marble Bar and Nullagine power station projects were modelled at the budgeted amounts.

Carnarvon power station project

Carnarvon, the largest town in the Gascoyne region, lies between Exmouth and Monkey Mia, 904km north of Perth and has a population of approximately 6,100.[121]

Prior to disaggregation, WPC had commenced a process to contract with an IPP to supply electricity to Carnarvon. Following its decision to bring some generation in-house, Horizon Power compared two IPP bids received during the Carnarvon Power Procurement process in October 2005 with two BOO options. The first BOO option was based on all capital expenditure occurring in the first year and the second BOO option

[120] Horizon Power (2011), Email from Horizon Power dated 15 March 2011

[121] Gascoyne Development Commission (2011), Submission to the inquiry into the funding arrangments of Horizon Power – Draft report, p2

proposed a phased approach to construction. The 2005 IPP bids were escalated by Horizon Power and scaled to match the anticipated demand forecast for Carnarvon to aid the comparison of options in early 2008. Based on its analysis of alternatives, Horizon Power selected the staged BOO approach to the project. Firstly, diesel generation would be installed at the site of the new power station to supply peak demand in the town then the new gas generation plant would be installed. After this, the old power station in Carnarvon would be decommissioned. As a result of the power station project, available capacity for the Carnarvon area will increase from 15MW to 19MW, an increase of 26.6 per cent.

The forecast capital expenditure for Carnarvon power station is $62.1m (real as at 30/6/2009) and the power station is due to be commissioned in 2013/14.

PB reviewed the business case for the Carnarvon power station development and discussed the lessons learned from Marble Bar and Nullagine. Horizon Power confirmed to PB that the cost estimates will be refined to ± 10 per cent prior to construction in an attempt to avoid the cost overruns of the previous generation projects.[122] In its conclusion, PB found the capital expenditure forecasts for the project to be prudent and efficient. Horizon Power subsequently advised the Authority that it has 81 per cent of the cost of the project fixed under contract and that the remaining 19 per cent are comprised of Horizon Power's own internal costs.[123]

South Hedland power station project

As mentioned in section 5 above, Horizon Power will experience a shortfall in generation capacity in the NWIS when its PPA with Alinta expires in December 2012.

The total generation capacity from Alinta's Port Hedland power station is contracted to a commercial third party. As not all of this contracted generation has been required by the third party, Alinta has been able to enter into a PPA to supply Horizon Power until December 2012. After this time the third party has stated that it will require 100 per cent of Alinta's capacity to fuel its expansion activities in the region.[124] Consequently the PPA between Horizon Power and Alinta cannot be renewed beyond 2012.

This contractual expiration leaves Horizon Power with a shortfall of installed capacity to meet its anticipated future demand of 145MW by 2013/14. Horizon Power has therefore forecast that it needs an additional 105MW of capacity by January 2013. This includes 40MW of reserve capacity[125] and some redundant generation capacity to cover maintenance and plant failure.

This situation is of particular relevance to the inquiry as Horizon Power is proposing the construction of a new power station at South Hedland to be commissioned on 1 July 2013. This single capital project represents just under 40 per cent of the total capital budget over the review period. The development of this new power station project is in response to increasing demand in the NWIS and the expiry of Horizon Power's PPAs with Alinta

[122] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 7.3.1, p69

[123] Horizon Power (2010), email dated 18 November 2010

[124] Horizon Power (2010), email dated 18 November 2010

[125] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, Schedule B, response reference number 41

Energy which combine to give a shortfall in supply capacity towards the end of the review period.[126]

The situation also impacts upon forecast operating costs as Horizon Power intends to cover demand over the period from 31 December 2012 (when the PPA with Alinta expires) to 1 July 2013 (when the new power station is commissioned) with additional electricity sourced through temporary mobile generation.

Horizon Power determined several viable options to meet this additional capacity requirement, to:

- renew or extend existing PPAs;
- contract with an IPP for an additional 100MW of capacity; and
- invest in new generation to build, own, operate (BOO) its own power station.

As outlined in section 5 above, the option to renew Horizon Power's existing PPA with Alinta beyond December 2012 is not considered possible on the understanding that after this date all of Alinta's generation capacity will be utilised by another company for its own anticipated expansion activities.

Of the two remaining options, Horizon Power determined that the BOO option is the preferred option on the basis of the highest net present value (**NPV**). This reasoning has formed the basis for development of the South Hedland Power Station. Whether or not this is the optimal solution depends on several issues such as:

- the accuracy of Horizon Power's comparison of the various options, e.g. if alternatives have been compared on a like-for-like basis regarding what costs are included and excluded and the rate of return applied to the various options;
- the extent to which options are re-costed and re-compared as the actual costs of the projects harden;
- what arrangements are assumed and costed, and which party bears the risk of this if the projects are delayed and temporary capacity is required to meet demand in the interim; and
- if Horizon Power's forecast of increased demand proves to be accurate.

Whether BOO or IPP, both options require the construction of a new 80-100MW power station by 1 January 2013. The four companies on Horizon Power's panel all submitted proposals. Two scenarios were proposed.

- Scenario 1 − to retain the current arrangement at Karratha (80MW OCGT[127]) and build a new 112MW CCGT[128] power station at South Hedland; and
- Scenario 2 – upgrade the Karratha power station to 102MW CCGT and build a new 83MW OCGT power station at South Hedland.

Horizon Power selected the option to BOO a CCGT 112 MW power station at South Hedland as this returned the largest NPV. The Authority sighted this information, prior to publication of the draft report but as the information is considered commercial in confidence it was not included the detail in the draft report.

[126] Horizon Power (2010), South Hedland Power Station – Business case for new generation, p7

[127] OCGT – Open Cycle Gas Turbine

[128] CCGT – Closed Circuit Gas Turbine

In its review, PB did note that several of the options considered were very close, within 8 per cent of each other and any slight amendment to the estimates in any option could alter the ranking.[129] Horizon Power responded by advising PB that a further cost estimation will be carried out prior to construction and, if this estimate exceeds a predetermined amount, it will resubmit the business case for further consideration.[130] However, there is no information submitted by Horizon Power to suggest that it would reverse the decision to build the new power station at South Hedland if costs did increase above the threshold.

The Authority did not recommend any specific reductions to the capital expenditure forecasts for the Carnarvon and Port Hedland power station projects. However, in both cases the Authority noted that:

- the preferred option was selected with a very narrow margin over the next best alternative;
- Horizon's inexperience relative to other providers meant that there was a greater likelihood for budgeting inaccuracies in the BOO options; and
- the occurrence of an actual cost overrun in Marble Bar and anticipated cost overrun in Nullagine suggests improvements are still required in Horizon Power project and cost management processes.

In the case of the larger South Hedland station, an investment decision was made on relatively preliminary costs, and it is unclear what course of action the Board will take if costs do increase.

Therefore, any cost overrun could mean that the selected alternative is not the efficient solution for generation at these locations. Consequently, should these projects again overrun the capital budget cost then any cost overrun should be borne by Horizon Power and not covered by the TEC.

Additionally, any operational cost implications from cost or time overruns from the power station construction process should not be covered by the TEC. A particular risk would be the extension of the additional mobile generation electricity costs in 2013 if the South Hedland Station did not meet its scheduled completion date.

Horizon Power submitted forecast cost information on the Port Hedland power station as its preferred and most efficient option for meeting demand in the NWIS by 2013. However, these forecasts are still subject to Government approval.

Transmission capital costs

After excluding assumed escalation, Horizon Power incurred annual average transmission capital costs of $1.0m (real as at 30/6/09) over the period 2006/07 to 2008/09 and submitted annual average (actual and forecast) transmission capital costs of $22.6m (real as at 30/6/09) for the period 2009/10 to 2013/14. The expenditure from 2010/11 to 2013/14 is predominantly driven by four planned transmission projects, which account for the majority (90 per cent) of forecast expenditure. PB reviewed three of these planned

[129] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Appendix 1, p121

[130] Parsons Brinckerhoff (2010), Email from P Walshe date 11 October 2010, 'Summary of PB's reponse to ERA comments on the draft report', item 20

capital projects and found a number of problems with each of the projects investigated as follows:

- Karratha to Roebourne 220kV line ($59.5m real as at 30/6/2009) – this project is contingent on an IPP generator (Rio Tinto Iron Ore (**RTIO**)) disconnecting from the NWIS. At the time PB published its report the date for the disconnection was still uncertain and therefore the likelihood that the expenditure on this project would be required over the review period was low.
- Dampier to Karratha 132kV line ($19.7m real as at 30/6/2009) – this project was also contingent on the RTIO disconnection and PB considered that the proposed system design following disconnection was not optimal. Therefore the project costs, with the exception of $0.4m to replace unserviceable transmission poles on the existing line, was deemed inefficient and was removed.
- Fairway Drive substation, Broome ($14.5m real as at 30/6/2009) – this project is to augment the existing substation at Fairway Drive to serve a new residential and industrial development north of Broome. PB noted that:
  - historically, demand in Broome had been overstated and, as such, a similar overstatement of forecast demand would have been included in the project specifications;
  - the development was only in its early stages and increased demand was contingent on specific residential development driving demand higher; and
  - there was limited evidence that other options, to the proposed augmentation, had been properly explored.

A more detailed explanation of PB's reasoning behind the proposed reductions can be found in its report.[131]

For the draft report the Authority was comfortable with PB's reasoning and adopted the proposed reductions as shown in Table 8.2 at the end of the section.

Distribution capital costs

After removing assumed escalation, Horizon Power incurred annual average distribution capital costs of $28.9m (real as at 30/6/2009) over the period 2006/07 to 2008/09 and actual and forecast transmission capital costs of $37.6m (real as at 30/6/2009) over the period 2009/10 to 2013/14. This is an increase of over 30 per cent in the average annual expenditure between the two periods.

In its initial submission to the inquiry Horizon Power proposed distribution capital expenditure across the whole of its supply area. In its investigation PB investigated two of the main projects. These were the wood pole reinforcement programme ($6.3m real as at 30/6/2009) mainly occurring around Esperance and Carnarvon and the Esperance Network Rural Upgrade Project (**ENRUP**) ($13.6m real as at 30/6/2009) to replace wooden poles that do not meet the required standards.[132]

Horizon Power has already conducted a stage one ENRUP programme (completed in March 2010) that concentrated on replacing non-compliant wooden poles that supported

[131] Parsons Brinckerhoff (2010_, Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 9.3, pp 93-100

[132] These standards are the 'AS1720.2 2006 Timber Structures, Part 2 Timber Properties as required under Electricity (Supply Standards and System Safety) Regulations 2001'

three-phase conductors. Horizon Power proposes to extend the ENRUP programme to non-compliant wooden poles that support single-phase conductors. The project will run to 2012 and will seek to replace poles that have failed an inspection and to reduce the number of long bays (long distances between poles).

In its report PB suggested that, in economic terms, the case for the ENRUP programme was:

> "..poorly supported and that rectification of the network should occur during the replacement of assets due to condition."[133]

Consequently PB recommended that poles which fail a condition inspection are replaced but that other defects can be addressed via the condition based replacement programme Horizon Power is adopting.

Following receipt of PB's final report Horizon Power asked Energy Safety to review the proposed reductions to the ENRUP programme. Energy Safety responded[134] suggesting that:

> " programmes agreed to ensure compliance with AS1720.2 as required under the (regulations) would need to be continued to optimise public safety."

In the draft report the Authority noted PB's comments on distribution capital expenditure and applied PB's proposed reductions to specific distribution projects as shown in Table 8.2. However, the Authority also noted that any safety issues around the recommended reductions to the ENRUP programme should be addressed in any submission Horizon Power may publish in response to the draft report.

Non system capital costs

Horizon Power incurred minimal non-system capital costs (i.e. those not directly relating to the generation or carriage of electricity) for the period 2006/07 to 2008/09 and submitted annual average actual and forecast non-system capital costs of $12.8m (real as at 30/6/2009) for the period 2009/10 to 2013/14. The majority of forecast capital expenditure in this category is associated with Horizon Power replacing Information Technology (IT) and fleet functions, previously supplied by Western Power through SLAs with in-house solutions.

As part of its investigation PB reviewed the proposed expenditure on IT, fleet and buildings management. Of these, PB found the proposed expenditure on IT and fleet appropriate and reasonable.

For proposed building expenditure, PB suggested that the $7.2m (real as at 30/6/2009) proposed for the Esperance depot was based on a building design that had larger capacity than would be required based on forecast staff numbers and so made a reduction accordingly. In the draft report the Authority supported this reduction and included it in Table 8.2. PB also suggested that Horizon Power should review its current strategy of providing free housing for regional staff, as an alternative 'housing allowance' may prove more economical and reduce ongoing expenditure. However, PB did not quantify the level of any possible savings.

[133] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 9.4.3, p109

[134] Email dated 8 November 2010

In the draft report the Authority reviewed and adopted PB's recommended reductions to specific transmission, distribution and non-system capital expenditure, as outlined in Table 8.2 below.

Also in its report PB noted that Horizon Power had a contingency of 10-30 per cent in project estimates to cover unforseen project risks. PB recommended reducing the 10 per cent contingency to 4.6 per cent in line with recent regulatory decisions by the Australian Economic Regulator (**AER**). The AER agreed the following risk contingencies:

- ElectraNet, 2.6 – 4.6 per cent depending upon the size of the project;
- Transgrid, 2.8 per cent; and
- Powerlink, 2.6 per cent.[135]

In the draft report the Authority accepted PB's suggested reduction in project risk contingency from 10 per cent to 4.6 per cent for non-generation projects. This decision was based on the Authority's analysis and comparison of the size of the capital programmes underlying the risk contingencies allowed for transmission service providers in the Eastern states.

- The forecast capital programmes for Powerlink and Transgrid are around \$475m to \$490m per annum, against which the AER allowed the lower risk contingency of 2.6 to 2.8 per cent.
- Electranet has a forecast capital programme of around \$155.6m per annum and received an upper risk contingency of 4.6 per cent. This capital programme is much closer in magnitude to Horizon Power's (\$168.2m per annum) and consequently the Authority considered that the project risk contingency be reduced in line with that agreed for Electranet.

For the draft report, the Authority also reviewed the contingencies implicit in the BOO generation projects and found these to be consistent with a 10 per project risk contingency. Notwithstanding PB's advice the Authority also applied the reduced project contingency to generation projects and included the reductions in the total reductions line in Table 8.2 below.

The Authority's recommended reductions to Horizon Power's forecast capital programme in the draft report are shown in Table 8.2 below.

[135] Parsons Brinckerhoff (2010), Final Report – Inquiry into the Funding Arrangements of Horizon Power – Operating and Capital expenditure review, Section 9.2.3, p96

Table 8.2 Draft report – draft recommended reductions to Horizon Power's actual and forecast capital programme ($m real at 30/6/2009)

Item	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Horizon Power submitted capital programme	100.1	278.4	216.0	179.2	67.8	841.6
Reductions by project						
TRANSMISSION						
• Karratha to Roebourne line	-	-	-	-	-9.2	-9.2
• Dampier to Karratha line	-	-	-12.1	-8.1	0.1	-20.0
• Fairway Drive substation	-	-	-	-1.2	-8.7	-9.9
DISTRIBUTION						
• Pole management programme	-	-	-0.8	-0.8	-1.7	-3.2
• ENRUP	-	-2.2	-3.6	0.2	2.3	-3.3
NON-SYSTEM						
• Esperance depot	-0.6	-	-	-	-	-0.6
ERA draft recommended capital programme	92.1	258.5	195.6	169.7	48.3	764.2
Total reductions[136]	-8.0	-20.0	-20.4	-9.5	-19.5	-77.4

Source: ERA analysis and PB Final report

The Authority also noted PB's comment on the incorrect escalators being applied to expenditure relating to the PUPP[137], which resulted in a proposed reduction of $25.7m (real at 30/6/2009) on a capital project total of $103.0m real at 30/6/2009). However, for the purposes of this inquiry, the reductions PB recommended regarding the PUPP concern capital expenditure that is outside of the regulatory asset base as this programme is externally funded.

The Authority made the following recommendation on capital expenditure in the draft report.

Horizon Power's actual and forecast capital expenditure programme be reduced by $77.4m (real at 30/6/2009) from $841.6m (real at 30/6/2009) to $764.2m (real at 30/6/2009) as detailed in Table 8.2.

8.2 Public submissions on the draft report

Five submissions were received in response to the draft report commented on the proposed capital expenditure reductions over the review period (Horizon Power, ATCO, the Office of Energy, WACOSS and the Kalgoorlie-Boulder Chamber of Commerce and Industry). All of these submissions are available on the Authority's website.[138]

[136] This includes the specific reductions to projects and a 5.6 per cent reduction on all capital expenditure to reduce the risk contingency from 10 per cent to 4.6 percent in line with PB's recommendations.

[137] PUPP is the Pilbara Underground Power Project

[138] Economic Regulation Authority website www.erawa.com.au

8.2.1 Horizon Power's submission

This section summarises the additional information forwarded by Horizon Power as to why the capital expenditure excluded in the draft report should be reinstated.

Dampier to Karratha transmission line

Horizon Power submitted a business case for a transmission project to replace its existing 132kV transmission line with a double 132kV circuit and to upgrade the transformer at Dampier. Horizon Power estimates that the total cost of the project will be $24.4 million (nominal), ($14.2 million in 2011/12 and $10.2 million in 2012/13).

Horizon Power maintains that the replacement of the existing single line is necessary as the line is in poor condition and prone to failures. The line is 36 years old and must be replaced by 1 January 2015 to comply with current energy safety legislation.[139] Furthermore, an additional circuit into Dampier must be provided by November 2012, as the contract with Rio Tinto Iron Ore (**RTIO**) expires on 1 January 2013 and the two 33 kV circuits will be disconnected. This would expose the Dampier system to the risk of the loss of its entire load due to outages on the single transmission line. Horizon Power modelled and costed three options for the project and selected the option that provided the lowest total cost and greatest resultant line capacity.

Horizon Power forecasts the load growth at the Dampier substation (currently 10MW) to increase to 23MW by 2017 to accommodate the new Water Corporation desalination plant (6.8MW by 2013 and a further 6.3MW by 2017).

From the information submitted in the business case Horizon Power requested that the full $24.4m (nominal) be included in the Authority's recommended efficient capital expenditure forecast.

Karratha to Roebourne 220 kV line

Horizon Power submitted a business case to install a new 220 kV transmission line from Karratha to Roebourne and install a new 220 kV terminal at Roebourne (to replace the existing line and terminal). Horizon Power estimates that the total cost of the project is $103.8m (nominal) commencing in 2013/14. Only $12.6m (nominal) is scheduled within the review period.

Horizon Power comments that the current transmission system between Karratha and Port Hedland is subject to thermal overloads and low voltage problems and that, once RTIO disconnects the system is prone to voltage collapse (lack of power transfer) at Karratha. Horizon Power has submitted information to demonstrate that it considered and costed five options to address the transmission issue in the area.

Now that the timing of the RTIO disconnection is known Horizon Power requested that the project proceed as originally planned and requests that the expenditure be reinstated in the forecast capital expenditure profile.

[139] AS1720.2 – 2006 Timber Structures. This details the expected life of timber poles (untreated jarrah) is 15-25 years below ground and 40 year above ground. The poles supporting the existing 132 kV line will be non-compliant by 2015.

Fairway Drive substation

Horizon Power submitted additional information in its submission in support of the capital expenditure ($14.9m real at 30/6/2009) forecast for the augmentation of Fairway Drive substation. PB recommended removing $9.9m real at 30/6/2009 on the basis that, in its opinion, demand in Broome was overstated and the timing of the proposed projects driving demand in north Broome was not finalised. Horizon Power requested that all of the expenditure excluded by PB should be reinstated for the final report.

Firstly, Horizon Power addressed the 'overstatement' of demand in Broome noted by PB it its report.[140] Horizon Power maintains that planning delays are usually initiated by third parties and result from labour shortages, finance approvals and project management. Consequently, Horizon Power reviews its demand and energy forecast annually and manages variations through the Mid Year Review process with Government. Horizon Power has prepared demand schedules for the new loads required around north Broome from:

- the new residential development;
- the new industrial park development; and
- the Woodside workers camp.

Horizon Power reviewed its capital expenditure profile at the Authority's request and confirmed that the capital expenditure for this project was commensurate with the anticipated new demand schedule for north Broome. On this basis Horizon Power requested that the capital expenditure related to the augmentation of Fairway Drive be reinstated in the forecast capital expenditure profile.

ENRUP single-phase programme and other pole management programmes

Horizon Power's pole management programme[141] is forecast by Horizon Power to cost $44.8m (nominal) in the period to 2013/14, comprising:

- the Esperance Network Rural Upgrade Programme (ENRUP) to upgrade the single phase rural network in Esperance ($15.7m nominal);
- ten other projects to monitor and replace wood poles in Esperance, West Kimberley, Broome, Gascoyne/Mid West, Kununurra, Derby, Carnarvon and the NWIS ($20.0m nominal) and aged steel poles in Carnarvon ($2.7m nominal);
- improved inspection equipment for network poles ($0.1m nominal);
- two pole reinforcement projects in Esperance and Carnarvon ($7.7m nominal); and
- an efficiency saving across all regions due to a shift to pole replacement based on the condition of the assets, rather than on the age of the assets (-$1.4m nominal).

PB in its report queried the cost of the ENRUP single phase programme, noting that the three-phase programme had resulted in a significant reduction in pole failures, insurance claims and incidents of conductor clashes. PB concluded that, due to the lower risks, the ENRUP single-phase programme is poorly supported and that the expenditure of $15.7m

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[140] Parsons Brinckerhoff (2010), Inquiry into the funding arrangements of Horizon Power – Operating and capital expenditure review, p98

[141] Parsons Brinckerhoff (2010), Inquiry into the funding arrangements of Horizon Power – Operating and capital expenditure review, p105

(nominal) is not justified. PB recommended a reduction in costs to $12.4m (nominal), which they estimated would be sufficient to replace all assets that do not meet asset condition requirements.

PB concluded in their report that Horizon Power's proposed expenditure on wood pole replacement projects was appropriate ($18.6m nominal).[142] However PB recommended a 48 per cent reduction in the expenditure on the steel pole replacement programmes (from $2.7m to $1.4m nominal) and the wood pole reinforcement programmes (from $7.7m nominal to $4.7m nominal) to take into account the reduction in the need for replacements or reinforcements due to asset condition monitoring.

In the business case for its pole management programmes, Horizon Power maintained that the aim of the pole management programme is to improve safety and reliability on the network and to comply with safety standards. Energy Safety notified the Authority in January 2011 of its concerns regarding Horizon Power's non-compliance with safety standards regarding the age of wooden poles (see Table 8.3 below). Australian Standard AS1720 requires wooden poles to be replaced or reinforced no later than 25 years after installation, and replaced no later than 40 years after installation.

Horizon Power regards its wood pole replacement programme as a high priority programme. Technically, Horizon Power maybe in breach of safety standards, and is exposed to legal challenge in the event of a safety incident. Horizon Power has therefore prioritised its expenditure on the programmes over and above other programmes and is consulting closely with Energy Safety and the Economic Regulation Authority to manage the risks associated with its wood pole management. For example, Horizon Power is working with Energy Safety on field trials in Esperance to identify methods of determining the need to replace wood poles on the basis of their condition rather than their age.

Horizon Power has indicated that budget constraints have contributed to past under-investment in its pole management programmes, with expenditure provided by the State Government on a year to year basis. This makes it difficult to establish to establish long-term contracts to implement long-term projects.

[142] This is the $20.0 million on the ten wood pole replacement programmes, net of the efficiency saving of $1.4 million due to condition-based assessment.

Table 8.3 Number of wooden poles non-compliant with Australian Standard AS1720.2[(a)]

Types of wooden poles	Number of poles inside planned asset life	Number of poles outside planned asset life	Per cent of poles in each category outside planned life
Treated	7,620	0	0
Untreated reinforced	7,324	879	11
Untreated non-reinforced	1,119	7,604	87
Total	**24,546**	**8,483**	**35**

Note: (a) The Australian Standard AS1720.2 sets out the age requirements for different types of wooden poles.

Source: Horizon Power

ENRUP Programme

The majority of Horizon Power's wooden poles are in Esperance and were installed in the early 1970s. In March 2010, Horizon Power completed a four-year project to upgrade the three-phase rural network in Esperance. The current project to upgrade the single phase rural network is an extension of this programme. The single phase upgrade programme will include replacing poles and reducing the number of long bays (long distances between poles). The scope of work for the single phase upgrade is included in Horizon Power's Asset Management Plan and Risk Mitigation Strategy, and conforms with the Wood Pole Asset Management Strategy developed by the company in 2010.

The ENRUP programme is being carried out through an alliance between Horizon Power and Transfield Service Ltd (TSL). Horizon Power maintains that the alliance has achieved good working relationships between the two companies and has met or exceeded the key performance indicators set in the alliance contract. The total value of the alliance contract is $7.5m (nominal) out of the $15.2m (nominal) total cost of the ENRUP project. The hourly rates in the TSL contract compares favourably with scheduled rates of alternative contractors (e.g. 84 per cent of the hourly rate for one alternative company).

Horizon Power has extended the contract with TSL for a period of two years after 15 December 2010. The extension allows the alliance to continue on to the single phase upgrade following the completion of the three-phase upgrade. The proposal considered the alternative of holding a competitive tender for new contractors, but did not recommend this option due to the risk of delays and higher costs of engaging alternative contractors and due to the satisfaction with the performance and cost effectiveness of the alliance with TSL.

Other Pole Management Projects

Horizon Power commenced work in July 2010 on a number of projects to reinforce and replace wood poles to meet the requirements of AS1702, in accordance with a reinforcement method approved by Energy Safety.

Other activities carried out by Horizon Power as part of its wood pole asset management since 2006 include:

- a review in 2008 of the actual age of assets inherited from Western Power at the time of disaggregation;
- field trials in Esperance in conjunction with Energy Safety to identify an improved inspection method to confirm the asset condition of wood poles;

- adoption of a Risk Mitigation Strategy to place priority on extreme and high risk safety conditions;
- adoption of an interim reinforcement strategy to address the risk of asset failure involving increased asset inspections of poles that are approaching the end of their asset lives, and replacing poles that are weak or in high risk fire areas; and
- refinement of the maintenance process to improve identification and replacement of compromised poles, and to assess asset conditions of removed poles to confirm inspection methods.

Non-system capital expenditure

Horizon Power did not submit a business case regarding the expenditure in this category that was excluded from the draft report. However, it did note it its submission that it did not support the reduction of $0.7m (nominal) proposed by PB on the capital expenditure associated with the Esperance depot. PB suggested the reduction based on the fact that the building design had larger capacity than was required given the forecast numbers of staff. Horizon Power comment that the depot building is over 50 per cent complete and that it is too late to change the design and reduce the size of the building.[143] For this reason Horizon Power has requested that the expenditure is reinstated.

Project contingency reduction

Horizon Power did not submit a separate business case regarding the reduction to capital expenditure resulting from decreasing the risk contingency in project estimates from 10 to 30 per cent down to 4.6 per cent. However, Horizon Power did note in its submission that its large geographic footprint, variety of climatic conditions and relatively small number of projects requires a higher level of contingency. Furthermore, Horizon Power considers that comparisons with large Eastern States distribution and transmission companies are 'inappropriate'.[144]

8.2.2 Other submissions

The submission from ATCO stated that:

> "ATCO strongly believes that (the recommendation) by the ERA should go further than just reducing the transmission, distribution and non-system costs but should also include reductions in the capital for new power generation infrastructure."[145]

ATCO also shares the Authority's concerns that the decision to bring power generation in house may not be the 'appropriate business model for a government entity to adopt'. In ATCO's opinion there is a:

> "..very competitive private sector market that could finance these activities and as such there is no need for Horizon to include new build power station capital costs in its capital plans."

The Office of Energy's submission[146] comments on two issues in relation to the modelling of forecast capital expenditure:

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[143] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, Schedule B, Response reference number 10

[144] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, Schedule B, Response reference number 30

[145] ATCO (2011), Inquiry into the funding arrangements of Horizon Power, p3

- including budgeted costs in the financial modelling for Horizon Power's generation projects, effectively excluding any costs associated with budget overruns − the Office of Energy suggested that exclusion of project cost overruns from capital expenditures concentrated attention on 'forecast accuracy' rather than the efficient level of costs and regional costs could be quite variable; and
- the application of a lower project contingency for capital projects − the Office of Energy also suggested that the use of Electranet's capital programme as a benchmark for determining a lower level of project contingency for Horizon Power may be problematic as this would not recognise the 'geographical diversity' of Horizon Power's service area and 'variability of Western Australia regional costs'.

WACOSS's submission does not comment on any of the proposed reductions to the forecast capital expenditure programme for Horizon Power but expresses concern about:

> "..the absence of information about any cost benefit analyses associated with Horizon Power's generation projects" and also "recommends the systematic publication of cost benefit analyses for future generation projects and more frequent use of audits."[147]

The submission from Kalgoorlie-Boulder Chamber of Commerce and Industry comments that:

> "..by reducing the utilities budget it is distinctly possible they will not be in a position to meet demand and continue to support the needs of regional enterprises when required."[148]

8.3 Authority comments

Power station projects

Horizon Power submitted its 'Post Project-Implementation Review'[149] for Marble Bar and Nullagine power station projects in a confidential appendix accompanying its submission in response to the draft report for the inquiry. From this the Authority notes that the main reasons identified for the cost and time overruns were that:

- the normal gating process for project delivery was not followed and the project went from the preliminary business case (gate 2) to execution (gate 4) – resulting in scope creep during the implementation phase;
- the contractual agreement between Horizon Power and its contractor, PowerCorp, was not sufficiently detailed on issues such as the sharing of risk and key performance measures (scope, cost, timing and performance criteria) – as the project progressed the two parties took increasingly divergent views that could not be resolved contractually because of the open ended terms of the service contract;
- Horizon Power's project management team was insufficiently experienced, under resources and under budgeted – this impacted upon the accuracy of the status reports and the effectiveness of corporate governance; and

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[146] Office of Energy (2011), Office of Energy's submission on the draft report for the inquiry into the funding arrangements of Horizon Power, Attachment 1, p2

[147] WACOSS (2011) WACOSS submission to the inquiry into the funding arrangements of Horizon Power – Draft report, p5

[148] Kalgoorlie-Boulder Chamber of Industry and Commerce (2011), Horizon Power inquiry, p1

[149] LogiCamms (2010), Marble Bar and Nullagine Power Station Project Post-Implementation Review Report, pp5-17

- the cost comparison of alternative options (IPP and BOO) was undertaken early in the project planning process when cost estimates were still subject to change.

The Authority is satisfied that the cost and time overruns, in the case of Marble Bar and Nullagine, did not result from poor forecast accuracy but from project management issues as identified in the post project implementation review, carried out by an independent third party (LogiCamms). Horizon Power has previously commented and PB noted in its report that Horizon Power has correctly identified the 'areas for improvement' to ensure future projects adhere to best practise project management. Therefore, the Authority is assured that its approach to:

- restrict forecast generation capital expenditure to budgeted levels; and
- apply the project contingency reduction to 4.6 per cent for generation projects.

is in line with Horizon Power's intent to better manage capital projects and costs in the future. Furthermore, this approach sends a strong signal that customers (via the TEC) should not be expected to pay for any errors of judgement or management in the execution of capital projects by Horizon Power and its contractors.

Dampier to Karratha Transmission Line

PB's main concern with this project was the uncertainty (at the time PB conducted its investigation) of the timing of the RTIO disconnection and that as Dampier only serves a small number of customers these could be supplied by a lower voltage line.

In reviewing the business case the Authority has noted that:

- the timing of the RTIO disconnection is now confirmed as is the timing of the expenditure on this project; and
- demand at Dampier is set to increase with the construction of Water Corporation's desalination plant. This increased demand load makes the possibility of 'distribution solutions' (as suggested by PB) to supply Dampier no longer feasible.

From the business case, the main reason for project appears to be the addition of a single new customer, Water Corporation, on the Burrup Peninsula. The current peak load at the Dampier substation is approximately 10MW, which is expected to grow to 17MW by 2013 with the addition of load for the new desalination plant. An additional 6.3MW for Stage 2 of the desalination plant will see peak load increase to 23MW by 2017. The replacement of the existing 132kV transmission line with a double circuit 132kV transmission line is to maintain Horizon Power's N-1[150] security of supply to the Dampier substation. Without the new load it could be argued that the small number (54) of customers at Dampier would not warrant the N-1 transmission standard.

As the expenditure forecast by Horizon Power is primarily driven by one contestable customer, Water Corporation, then the Authority suggests that the majority of additional costs required to upgrade the infrastructure to be able to supply this customer should be met by Water Corporation. Water Corporation's customer contribution to the project costs and its ongoing bi-laterally negotiated supply contact with Horizon Power should be sufficient to cover the costs of the additional supply it requires.

[150] N-1 is a transmission network reliability measure such that if one power supply on the transmission network is lost, power is quickly restored

The Authority recognises that Onslow customers will also benefit from the replacement of the existing transmission line with a double circuit 132kV transmission line. However the Authority, given the information available, is unable to quantify this benefit. Therefore the amount of this potential benefit cannot be reinstated into the efficient capital expenditure forecast for the review period.

Consequently, the Authority considers that the expenditure on the Dampier to Karratha transmission line continues to be excluded in its entirety from the forecast of efficient capital expenditure in the final report.

Karratha to Roebourne 220 kV transmission line

In its report, PB noted that the need and long term scope of the project was well defined but that the timing of the project was unclear given the then uncertainty around the RTIO disconnection.

Consequently, now that the timing of RTIO's disconnection is confirmed as 1 January 2013, more detailed project timing and costing can proceed. In its comments on this project, Horizon Power confirmed that the planning, design and construction timeframe of the project is around 2.5 to 3.5 years and so the new target commissioning date is November 2014.

Given the timeframe and additional planning still to be undertaken on this project, the Authority suggests that it is unlikely that expenditure on this project will be required within the review period and so has decided not to reinstate the forecast capital expenditure. The exclusion of capital expenditure therefore remains consistent with the draft report.

Fairway Drive augmentation

In reviewing the additional information submitted by Horizon Power on the Fairway Drive substation the Authority is again concerned that the main drivers for the increased demand forecast north of Broome are again a small number of large customers, developers in the case of the industrial and residential developments and Woodside for its temporary accommodation camp. The main load drivers are identified as follows:

- Broome Road industrial area – 14 MVA[151] by end of March 2011;
- Waranyiarri Estate residential development – approximately 77 MVA by March 2014; and
- Woodside's workers accommodation camp – 2.25 MVA by early 2012.

Consequently, the Authority has considered applying the same principle here as it applied for the Dampier to Karratha transmission line. That is, the customers driving the demand that necessitates augmented of the existing substation, should cover the cost of the infrastructure augmentation. However, the 'customer pays' principal is less clear for Fairway Drive substation project as, ultimately, the industrial and residential developments will be occupied by small business and residential customers on uniform tariffs. The Authority has calculated that the discounted weighted average tariff[152] for Broome excluding this additional demand and excluding the additional capital expenditure associated with this project is $0.34. If the additional capital project expenditure and increased demand is added to the tariff calculation, the average discounted weighted

[151] MVA stands for mega volt ampere.

[152] The discounted weighted average tariff is the total capital expenditure on transmission assets in Broome for the review period divided by the total demand in kWh over the review period discounted to real prices as at 30/6/2009.

average tariff for Broome decreases to $0.32. This suggests that, following the augmentation of the Fairway Drive substation the cost of the project is more than offset by the increased demand supplied so that, on average, the unit cost per kWh decreases.

For this reason the Authority has reinstated the capital expenditure associated with this project. However, the Authority would expect Horizon Power to ensure that the customer contribution received from Woodside and the ongoing electricity supply contract fully covers the cost of providing the additional supply to the workers accommodation camp.

ENRUP and Pole Management Programmes

The Authority considered the additional information submitted from Horizon Power and Energy Safety in light of its ongoing discussions with Horizon Power is consistent with requirements under its licensing requirements. The Authority has decided to reinstate the capital expenditure on wood pole management programmes because:

- this is regarded as high priority expenditure due to non-compliance with safety standards and exposure to risk of litigation in the event of a safety incident;
- management of ENRUP programme appears efficient due to Horizon Power's successful partnership with Transfield;
- the current non-compliance is due to past under-investment in this area. Future capital expenditure needs to provide for establishment of long-term contracts and programmes to address non-compliance issues; and
- it would be consistent with the high-risk high-priority nature of this programme to allow the proposed capital expenditure to provide Horizon Power with adequate resources to catch up in this area and become fully compliant.

Overall, capital expenditure of $6.2m (real at 30/6/2009) has been reinstated in the Authority's revised recommended capital expenditure forecast for the review period.

The Authority has decided to continue to exclude the proposed expenditure on steel pole replacement ($0.3m real at 30/6/2009), initially recommended by PB, as the Authority agrees that a new replacement strategy based on pole condition and not age will reduce the number of steel poles requiring replacement. As noted in PB's report:

> "Given that new steel pole inspection criteria have been introduced in 2010 and a four year inspection cycle applies, the condition of most steel poles will have been assessed before this programme commences."[153]

Non-system capital expenditure

The Authority has noted the sizeable amount of non-system capital expenditure $75.1m (real at 30/3/6/2009) included in Horizon Power's forecasts for the review period. This includes:

- IT projects ($38.4m real at 30/6/2009);
- building expenditure ($23.5m real at 30/6/2009); and
- fleet expenditure ($13.2m real at 30/6/2009).

[153] Parsons Brinckerhoff (2010), Inquiry into the funding arrangements for Horizon Power – Operating and capital expenditure review, p 107

In its report PB commented that it had reviewed the business cases for the different projects and expenditures. PB noted that Horizon Power had considered an appropriate range of options for each project, the project scopes were reasonable, selection of the preferred option was conducted in an appropriate manner and the timing of expenditures was driven by the separation of legacy systems. Consequently, with the exception of the redevelopment of the Esperance depot, PB did not recommend any reductions in capital expenditure forecasts on non-system capital expenditure.

The Authority accepts that Horizon Power is in the midst of replacing the majority of its legacy IT systems and fleet arrangements following disaggregation and has accepted PB's comments on the appropriateness of the expenditure given the projects currently underway. This is on the expectation that new IT systems will deliver 'fit for purpose' solutions and that by bringing the fleet arrangements in-house, Horizon Power would deliver a $4.7m net present cost benefit over a 10 year period.[154]

However, the Authority also notes that Horizon Power included, in the additional operating cost business cases it submitted following the draft report, a business case for $5.3m (real at 30/6/2009) of operating costs to support the IT capital projects. The Authority has confirmed with Horizon Power that this operating cost expenditure relates to the ongoing cost of consultants and specialist personnel to implement the new IT systems and that the contracts for these staff were competitively tendered. Consequently, the Authority has separately included both the operating costs and capital costs associated with providing replacement systems for when the existing SLA for IT support from Western Power expires in 2012.

The Authority has continued to exclude the $0.6m (real at 30/6/2009) capital expenditure from the Esperance depot redevelopment in the final report on the basis that the project cost should not have been approved with additional capacity in the depot over and above that required for the planned staffing levels. The fact that the redevelopment is currently in progress and cannot be easily altered has not influenced the Authority's decision to exclude costs associated with the surplus capacity.

Project contingency reduction

The Authority notes that the submissions from both the Office of Energy and Horizon Power commented that the reduction in project contingency allowance from 10 per cent to 4.6 per cent was questionable given the unique nature of Horizon Power's operational environment. However, with the exception of the ongoing pole management programme, the generation, transmission and non-system projects have discrete geographic locations and as such, known climatic conditions for any particular project. Furthermore, the Authority ensured that it compared the project contingency allowances for service providers in the Eastern States that had a capital programme of a similar size to that of Horizon Power. The Authority considers that insufficient information has been received for it to change its assumption on the project contingency reduction. In addition, given Horizon Power's recent project overspends on its Marble Bar and Nullagine generation projects it is important to reinforce the requirement for focussed project and cost management. Consequently, the Authority has maintained the project contingency reduction from 10 per cent to 4.6 per cent across the whole capital expenditure programme in the final report.

[154] Parsons Brinckerhoff (2010), Inquiry into the funding arrangements for Horizon Power – Operating and capital expenditure review, p 115

Table 8.4 Revised reductions to Horizon Power's actual and forecast capital programme ($m real at 30/6/2009)

Item	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Horizon Power submitted capital programme	100.1	278.4	216.0	179.2	67.8	841.6
Revised reductions by project						
GENERATION						
• Marble Bar and Nullagine power stations (cost overruns)	-3.2	-3.3				-6.5
TRANSMISSION						
• Karratha to Roebourne line	-	-	-	-	-9.2	-9.2
• Dampier to Karratha line	-	-	-12.1	-8.1	0.1	-20.0
DISTRIBUTION						
• Pole management programme	-	-	-0.1	-0.1	-0.1	-0.3
NON-SYSTEM						
• Esperance depot	-0.6	-	-	-	-	-0.6
ERA revised recommended capital programme	**92.3**	**260.8**	**210.7**	**178.8**	**55.5**	**798.2**
Total reductions[155]	-7.8	-17.6	-5.3	-0.4	-12.3	-43.4

Source: Horizon Power additional information submitted in February and March 2011 and ERA analysis. Totals may not add due to rounding.

The reductions to the capital programme for the final report ($43.4m real at 30/6/2009) are smaller than the reductions to the capital programme recommended in the draft report ($77.4m).

The case for reinstating capital expenditure relating to Horizon Power's pole management programme is clear, given the Authority's recent communications with Horizon Power and Energy Safety regarding Horizon Power's potential contravention of electricity safety and supply regulations.[156] Horizon Power has a substantial number of its wooden poles (35 per cent) that are non-compliant with the regulations and so Horizon Power requires sufficient funds to be able to reinforce or replace these assets to ensure compliance with safety regulation and its licence conditions.

The case for reinstating the Fairway Drive project is that the augmentation being driven by a number of residential and small business customers who will eventually occupy premises in the residential and industrial developments planned for the north of Broome. As small use customers are essentially driving the need for the project then it is reasonable that a prudent and efficient electricity service provider would fund this capital development though its tariff, CSO and TEC revenue.

The Authority's final recommendation is shown below.

[155] This includes the specific reductions to projects and a 5.4 per cent reduction on all capital expenditure to reduce the risk contingency from 10 per cent to 4.6 per cent in line with PB's recommendation.

[156] Regulation 16(1) of the Electricity (Supply Standards and System Safety) Regulations 2001 which requires Horizon Power to comply with AS1720 parts 1 and 2. This required wood poles (untreated jarrah) to be replaced or adequately reinforced not later than 25 years after installation and replaced not later than 40 years after installation.

8.4 Final recommendation

8) Horizon Power's actual and forecast capital expenditure programme be reduced by $43.4m (real at 30/6/2009) from $841.6m (real at 30/6/2009) to the suggested efficient level of $798.2m (real at 30/6/2009) over the review period, as detailed in Table 8.4.

9 Return on Capital

Investors have a right to expect a return on the value of their assets equal to the efficient cost of capital associated with the regulated activities. As assets are often financed by a combination of debt and equity, so the return on assets should compensate both providers of debt and equity holders. For this reason the Weighted Average Cost of Capital (**WACC**) is often used to refer to the average cost of debt and equity capital, weighted by the proportion of debt and equity that reflects the financing arrangements for the assets.

For this reason, the WACC is used by the Authority and other utility regulators to set the required rate of return for regulated, natural monopolies, e.g. gas, electricity, water and rail networks. More detailed technical information on the WACC methodology and calculation is given in Appendix H.

9.1 Background

For this inquiry, Horizon Power initially proposed a real pre tax WACC of 8.88% that utilised information from a study conducted by Deloitte. Horizon Power then revised its estimate of market risk premium and equity beta in its submission on the draft report and forwarded additional information to support its arguments.

The Authority considered Horizon Power's proposed WACC and the underlying parameters from which it was calculated in the preparation of both the draft and final reports. However, on consideration of the available market evidence the Authority recommended different WACC values for inclusion in the financial modelling for the inquiry. Information on Horizon Power's initial set of underlying WACC parameters are reproduced in Table 9.1 below.

The WACC proposed for Horizon Power and modelled in the draft report was expected to change prior to publication of the final report for the inquiry. This was because, just prior to publication of the draft report, the Authority also released a discussion paper on the intended method to estimate the debt risk premium (debt margin)[157] and invited public submissions. Subject to the Authority's consideration of feedback on the discussion paper, it was the intention of the Authority to use the proposed method for calculating the debt risk premium in its regulatory roles and also when undertaking inquiries referred to the Authority by the State Government.

As a result, the calculation of the rate of return detailed for the Horizon Power inquiry and outlined in Section 9.3 below has been informed by the submissions received on and conclusions drawn from the cost of debt discussion.

[157] Economic Regulation Authority 1 December 2010, Measuring the Debt Risk Premium: A Bond Yield Approach, available on the ERA website www.erawa.com.au

Table 9.1 Horizon Power's initial proposal for the cost of capital

Parameter	Estimate	
	Low	**High**
Market Risk Premium	6.0%	7.0%
Cost of equity (post-tax)	11.23%	13.93%
Cost of debt (pre-tax)	7.23%	7.43%
Gearing: equity to total value	40%	40%
Gearing: debt to total value	60%	60%
Beta	0.8	1.0
Tax rate	30%	30%
Specific Company Risk Premium	1.0%	1.5%
Weighted Average Cost of Capital (WACC)		
Nominal Post Tax WACC	7.5%	8.5%

Source: Deloitte 2009, "Horizon Power: Weighted Average Cost of Capital Analysis"

Horizon Power's main points of difference from the Authority in the values of underlying WACC parameters concern the cost of debt, the value of imputation credits, market risk premium and equity beta. These arguments are covered in section 9.2.1 below.

In the draft report, the Authority assumed a benchmark rate of return for Horizon Power, even though Horizon Power has access to debt funding at favourable rates from the State Government. Using a benchmark rate of return in the cost of service model will result in a higher 'balancing revenue' item than if Horizon Power's actual rates of borrowing are used to determine the WACC. The impact upon the balancing revenue item of using a benchmark return or return based on actual borrowing costs has been determined by:

- calculating cost-reflective tariffs using a benchmark return on capital; and
- calculating the cost of service (used to determine the balancing revenue item) again but using Horizon Power's actual borrowing characteristics to determine an alternative return on capital.

The alternative return on capital was calculated using Horizon Power's actual nominal cost of debt funding.

TEC values were derived from each run of the cost of service model and compared in the draft report.

Based on this analysis the Authority made two recommendations in the draft report relating to the cost of capital as listed below.

A real pre tax benchmark WACC of 6.49 per cent be used for regulatory modelling and calculation of cost-reflective tariffs for this inquiry.

A real pre tax alternative WACC of 4.89 per cent, reflecting Horizon Power's actual cost of debt, be used for determining TEC levels in this inquiry.

9.2 Public submissions on the draft report

Four of the public submissions received in response to the draft report for the inquiry commented on the cost of capital (Horizon Power, Western Power, Alinta and WACOSS). All of these submissions are available on the Authority's website.[158]

9.2.1 Horizon Power submission

Horizon Power's submission suggests several examples of how it faces substantially more risk than Western Power. These are:

- the fragmented nature of Horizon Power's networks compared to Western Power's interconnected system;
- input prices that are generally higher and more volatile than those faced by Western Power; and
- customer growth rates that are generally more volatile than Western Power's.

Consequently, Horizon Power considers that this additional risk should be accounted for in the WACC calculated for the inquiry and so has proposed, and provided supporting evidence for, changes to key parameters. These are listed in Table 9.2 below.

Table 9.2 Final report – Horizon Power's proposed changes to WACC parameters

Parameter	Value used in draft report	Horizon Power's proposed value for the final report
Market Risk Premium	6.0%	8.0%
Equity Beta	0.7	1.0

Source: Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, pp 39-44

Horizon Power's submission also comments on the use of an 'alternative WACC' based on Horizon Power's actual cost of borrowing. The main concern is that, in its opinion, the benchmark real pre tax WACC of 6.49 per cent (as calculated for the draft report) contributes to a deteriorating financial position over the review period. Horizon Power submitted that using an even lower WACC value would further erode Horizon Power's financial position.[159]

9.2.2 Other submissions

The Western Power submission does not comment on the WACC value used in the financial modelling for the Horizon Power inquiry but rather the methodology used to calculate WACC parameters and in particular the debt risk premium. Western Power is of the opinion that:

> "..the ERA's proposed methodology is that it will systematically underestimate the cost of capital for a regulated business" and that there is "..a significant risk that the return on investment will not be sufficient to attract funds and will ultimately lead to the inefficient deferral of investment."[160]

[158] Economic Regulation Authority website www.erawa.com.au

[159] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, p44

[160] Western Power (2011), Submission to draft report on Horizon Power's funding arrangements, p3

Alinta's submission supports the use of a 'benchmark WACC' in the determination of cost-reflective tariffs but not to calculate the TEC. Alinta's submission does not support the suggestion by the Authority in the draft report to use an 'alternative WACC' and instead offers another option. This is to calculate a 'direct revenue requirement' for Horizon Power based on efficient operating and capital expenditure, efficient depreciation expenses and a 'benchmark' return on debt capital only. Alinta suggests that the amount of the TEC is then the difference between the direct revenue requirement and the amount of actual and forecast revenue earned by Horizon Power. This methodology effectively makes returns on equity discretionary.

WACOSS's submission directs the Authority to its earlier submission and recommendations in response to the discussion paper on debt risk premium.

9.3 Authority comments

The Authority noted the examples Horizon Power's listed in its submission of how it believes it faces more risk than Western Power. The Authority understands the operational and reliability problems associated with having multiple islanded systems as opposed to a single interconnected system. Furthermore, it has acknowledged greater price volatility by adopting forecast BCI as an escalator for Horizon Power over the review period with the understanding that BCI has fluctuated around CPI historically. Whilst customer growth rates maybe more volatile in some parts of Horizon Power's area, there are also areas, such as in the Mid West, that historically show little customer volatility or demand growth.

The main points of difference between Horizon Power's WACC parameters and the Authority's WACC parameters are listed below. A full discussion of the individual parameters is given in Appendix H.

9.3.1 Cost of debt

The Deloitte report recommended a debt margin of 180 to 200 basis points above the risk free rate to reflect Horizon Power's mix of government subsidised and commercially available debt. Deloitte used a mix of Australian and US bonds (with credit ratings of A and BBB) to determine credit spreads. Deloitte's suggested debt margin over the nominal risk free rate gave a cost of debt of between 7.23 per cent and 7.43 per cent (pre tax).

The Authority suggested that only Australian corporate bonds with a credit rating of BBB-, BBB and BBB+, and terms to maturity of two year or longer, should be used to derive the debt margin for regulated businesses. Using different weighted average approaches, the Authority then calculated the debt margin for the sample of 15 bonds that fitted its criteria over the 20-trading-day period to 31 October 2010, which gave a benchmark debt margin of 330.5 basis points over the nominal risk free rate of 5.10 per cent, plus an allowance for debt raising costs of 12.5 basis, points to give an overall nominal cost of debt of 8.53 per cent (pre tax) in the draft report. The Authority also used Horizon Power's estimated actual nominal cost of debt (6.46 per cent) to calculate an alternative WACC to determine TEC levels.

9.3.2 Value of imputation credits (Gamma)

Value of imputation credits (Gamma) – Deloitte suggested that the WACC should not be adjusted for gamma as Horizon Power is government owned and tax benefits attached to franked dividends cannot be realised by government. The Authority did not agree with this suggestion based on available empirical evidence[161] and set a gamma of 0.535.

9.3.3 Market risk premium (MRP)

The Authority notes that, on the advice of its consultant on the issue of MRP, Economic Insights,[162] Horizon Power proposed a MRP of 8.0 per cent. This proposed MRP of 8.0 per cent was mainly derived by Bishop and Officer from the Value Advisor Associates (**VAA**) in its 2009 study.

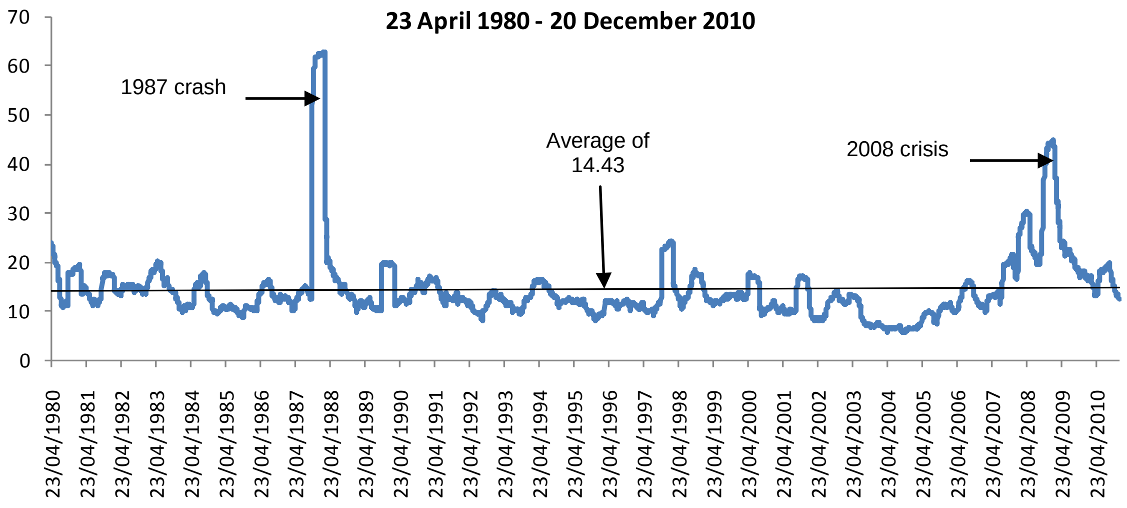
The Authority considers that the most significant issues leading VAA to propose a departure from the previously adopted method of using historical data on equity premium to derive a forward looking MRP are:

- the unusual current economic circumstances, in the form of the global financial crisis; and
- the substantive increase in risk spreads on debt for the regulatory period from 2010 to 2014.

In support of these arguments, the VAA used historical data from Bloomberg on annualised 90-day moving volatility of the All Ordinaries Accumulation Index and the implied volatility of call options of different maturity (1 month, 3 months, and 12 months) to illustrate what the VAA calls unusual economic circumstances for the period from 1980 to 30 November 2009.

The Authority has considered the same approach but with the updated data set from Bloomberg until 20 December 2010. However, the Authority considers that risk cannot be solely measured by a level of volatility.

Figure 9.1 90-Day Moving Volatility of All Ordinaries Accumulation Index



Source: Bloomberg

Figure 9.1 shows a 90-day moving average of the volatility of the All Ordinary Accumulation Index for the period from 23 April 1980 to 8 December 2010. Current volatility in the equity market is currently lower than at the peak of the crisis level, and has

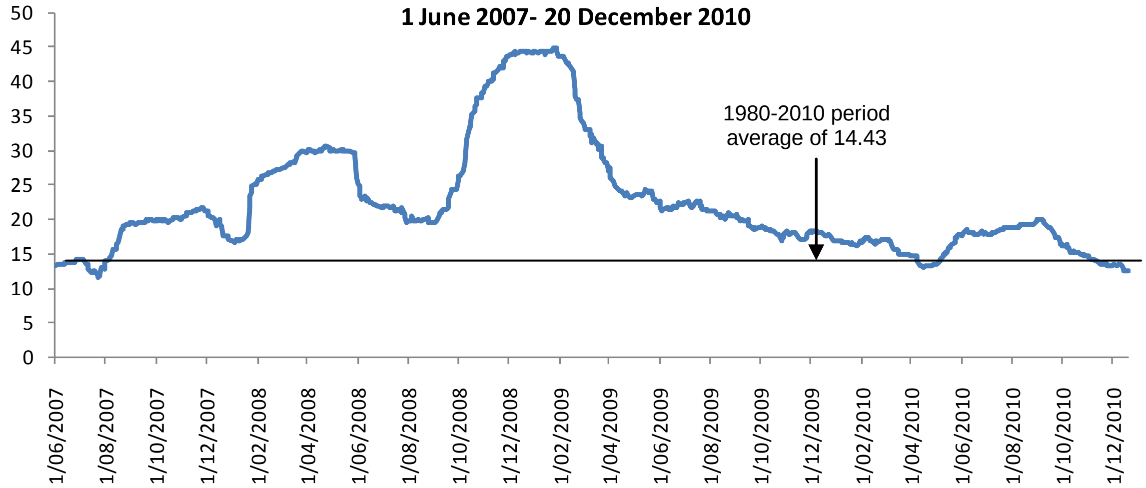
[161] Refer to Appendix H – Technical information on WACC

[162] Economic Insights (2011), Comments on the ERA draft report on funding of Horizon Power, p24

almost returned to the pre-crisis level. This is consistent with the observation in the draft decision in August 2010.

The Authority is of the view that the argument by VAA that the equity market is experiencing an unusual period of high volatility is not justified. Figure 9.2 illustrates the 90-day moving volatility of the All Ordinaries Accumulation Index for the period before and after the crisis (1 June 2007 to 20 December 2010). In addition, the long term average of 14.43 for the 90-Day moving volatility slightly lies above the current level of volatility as shown in Figure 9.2. This is consistent with the observation in the draft decision in August 2010 and also consistent with Alinta's view in its submission.

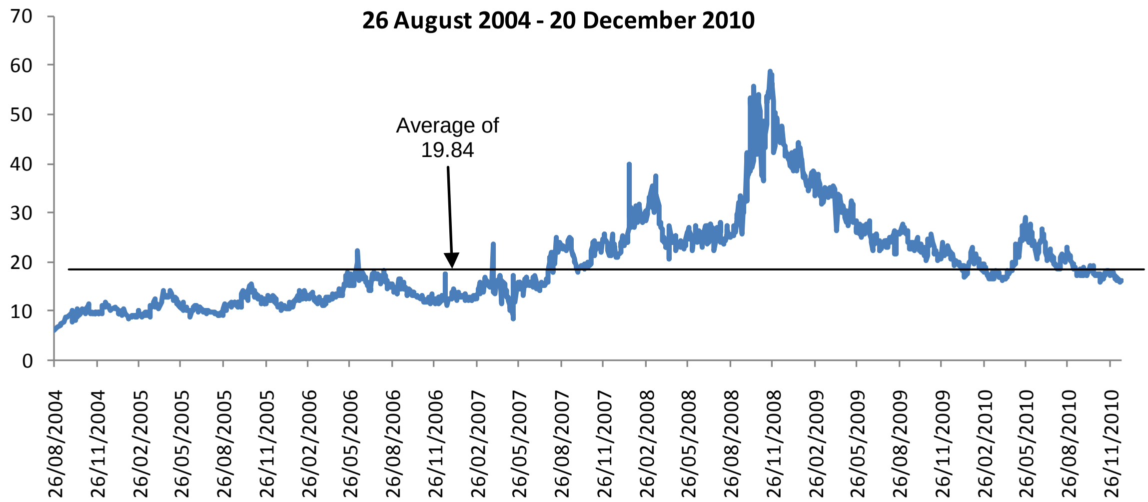
Figure 9.2 The 90-Day Moving Volatility of All Ordinaries Accumulation Index, pre-and post the 2008 global financial crisis



Source: Bloomberg

The Authority agrees that a current view of market volatility can be derived from trades in options on the ASX 200 Index, although the Authority recognises that this is only one of many approaches that could be employed. The data set from Bloomberg from 26 August 2004 to 20 December 2010 (the longest data set available from Bloomberg), rather than the data set used by VAA, for the period until September 2009, shows that the level of market risk has returned to around the average level. Figure 9.3 below supports the Authority's view that the market risk has returned to the pre-crisis level that market risk has returned to the pre-crisis level.

Figure 9.3 Implied volatility from 3-month call option on ASX 200



Source: Bloomberg

The Authority is of the view that there is now evidence to suggest that market conditions have stabilised. This view is supported by the reports released by the Reserve Bank of Australia (**RBA**), the International Monetary Fund (**IMF**), and the Organisation for Economic Cooperation and Development (**OECD**). In all these reports, it is widely agreed that the Australian economy has displayed strong resilience and robustness during and after the 2008 Global Financial Crisis.

The RBA was of the view that:

> 'Employment growth has been robust, business and consumer confidence is above average, the housing market has been strong, and there are signs that the period of business deleveraging is coming to an end. Collectively, these outcomes provide us with some confidence that the economy is now in a reasonably solid upswing.'[163]

and

> 'Our economy recovered relatively quickly from what was a shallow downturn following the global financial crisis, and over the past year has grown around its trend rate of 3¼ per cent. Domestic demand has grown substantially faster than this – about 5¼ per cent – due importantly to growth in public spending, though this is moderating now…
>
> Business conditions are generally around average levels, although there are clear differences across sectors. Business investment is at a high level, particularly in the mining sector, and information published by the Australian Bureau of Statistics, as well as our own liaison with companies, suggests that it will pick up sharply further over the next couple of years'.[164]

and

> "In November, the Reserve Bank Board increased the target for the cash rate from 4.50 per cent to 4.75 per cent, the first change to the target in six months. Money market yields

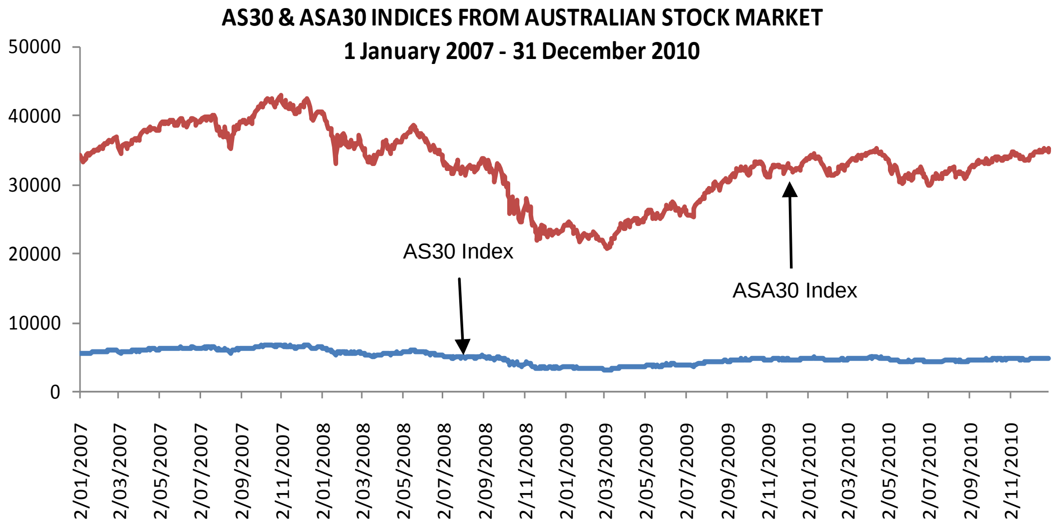
[163] The Reserve Bank of Australia, May 2010, 'Recent Developments in the Global and Australian Economies', available at http://www.rba.gov.au/speeches/2010/sp-ag-250310.html accessed on 8th December 2010

[164] The Reserve Bank of Australia, May 2010, 'Recent Developments in the Global and Australian Economies', available at http://www.rba.gov.au/speeches/2010/sp-dg-181110.html accessed on 8th December 2010

suggest markets currently expect a further increase in the cash rate in the first half of 2011”.[165]

In addition, the Australian share markets significantly recovered from the crisis level. This view is illustrated in Figure 9.4 below.

Figure 9.4 Australian Stock Exchange All Ordinaries Index (AS30 Index) and ASX Accumulation All Ordinaries Index (ASA30 Index).



Source: Bloomberg

In November 2010, the OECD concluded that:

> ‘After weathering the crisis well in 2009, the Australian economy is projected to experience strong growth in 2010 and 2011, above its trend rate. Activity might expand by as much as 3¼ per cent and 3½ per cent in these two years, driven by booming exports and domestic demand. The unemployment rate is expected to fall below 5 per cent by the end of 2011, in a context of moderate inflation.’
>
> ‘The Australian economy, fuelled by the mining boom, should grow robustly in 2011 and 2012 at a rate of between 3½ per cent and 4 per cent. Strong growth, driven by terms of trade gains and dynamic investment, will reduce unemployment.
>
> The projected increase in demand is likely to require a further tightening of monetary conditions to ensure that a non-inflationary recovery remains on track. The current fiscal consolidation plan must be pursued, as assumed in the projections, to rebuild the margins for manoeuvre used during the crisis. Reforms are needed to strengthen supply capacities in the housing and infrastructure sectors to reduce bottlenecks, which the mining boom is likely to exacerbate.’[166]

The IMF shared the views of the RBA and the OECD with regard to conditions for Australian economy. They state that:

> The global downturn had a fairly small impact on the Australian economy, as real investment barely contracted in 2009 and the unemployment rate went up by less than 2

[165] The Reserve Bank of Australia, November 2010, “Statement on Monetary Policy”, available at http://www.rba.gov.au/publications/smp/2010/nov/html/index.html, accessed on 8th December 2010

[166] The OECD, November 2010 ‘Economic outlook for Australian economy’, available at http://www.oecd.org/document/15/0,3343,en_2649_34573_45268687_1_1_1_1,00.html accessed on 8th December 2010

> percentage points. Not surprisingly, Australia's potential growth is estimated to have declined by just 1/3 per cent to 3.1 per cent in 2009.[167]

Given all available information from both domestic and international sources, the Authority is of the view that the market conditions in Australia have stabilised significantly since the Global Financial Crisis in 2008. As such, the Authority considers there is no persuasive evidence to depart from the previously adopted method of estimating the MRP using historical data on the equity risk premium for the purpose of this inquiry.

9.3.4 Equity beta

The Deloitte paper and a later paper by consultants Economic Insights supported a higher equity beta (0.8 to 1.04) than had been adopted by the Authority, to accommodate the extra risk associated with a smaller company such as Horizon Power. The Authority did not support the consultants' use of US and other countries' data to calculate beta. Instead, the Authority decided that as Australian data have been used to calculate all other parameters in the WACC it should also be used for beta.

The Authority considers that in ascribing a value to the equity beta, primary reliance should be placed on capital market evidence and statistical estimates of beta values, where these are available for comparable businesses.

An analysis undertaken by Associate Professor Olan Henry for the AER produced estimates of beta values for Australian electricity and gas network businesses and portfolios of the businesses using weekly return data over a period of six years and eight months from 1 January 2002 to 1 September 2008. Two statistical estimation techniques were applied (ordinary least squares and least absolute variation). Summary results are shown in Table 9.3 and Table 9.4. All values shown are equity beta values at a financial gearing of 60 per cent debt to assets.

[167] The Yan Sun, '*Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis*', IMF Working Paper, WP/10/27, May 2010, pp 19

Table 9.3 Henry equity beta estimates and 95 per cent confidence intervals for individual Australian electricity and gas network businesses (2002 – 2008)[168]

Business and number of data points	Estimation method	
	OLS	LAV
Alinta (294)	0.93 (0.58 – 1.28)	0.59 (0.22 – 0.96)
AGL (252)	0.74 (0.35 – 1.13)	0.54 (0.19 – 0.89)
Australian Pipeline Trust (348)	0.73 (0.51 – 0.95)	0.63 (0.41 – 0.85)
GasNet (255)	0.32 (0.14 – 0.50)	0.24 (0.06 – 0.42)
Envestra (348)	0.25 (0.15 – 0.35)	0.10 (-0.02 – 0.22)
DUET (212)	0.35 (0.21 – 0.49)	0.25 (0.11 – 0.39)
Hastings* (194)	1.01 (0.68 – 1.34)	0.50 (0.15 – 0.85)
SP AusNet (142)	0.27 (0.03 – 0.51)	0.23 (-0.01 – 0.47)
Spark Infrastructure (79)	0.59 (0.16 – 1.02)	0.76 (0.33 – 1.19)
Average	0.58	0.43

* Hastings Diversified Utilities Fund

Table 9.4 Henry/AER equity beta estimates and 95 per cent confidence intervals for portfolios of Australian electricity and gas network businesses (2002 – 2008)[169]

Sample and number of data points	Estimation method	
	OLS	LAV
Australia – mean portfolio (348)	0.44 (0.34 – 0.54)	0.44 (0.36 – 0.52)

Statistical estimates of beta values for Australian energy network businesses in the period since 2002 point to a value of equity beta at a gearing of 60 per cent debt to assets to be in the range of 0.45 to 0.7.

The Authority notes that the AER considers that the reasonable range of the equity beta for a gas or electricity distribution network of between 0.4 and 0.7 is justified on the grounds of empirical information. The AER has also considered the need for regulatory certainty and adopting a conservative approach in estimating the equity beta, commensurate with prevailing market conditions and the risks involved in providing reference services. On this basis, the AER considers that a value of 0.8 provides best estimate of the equity beta arrived at on a reasonable basis for gas and electricity

[168] Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 234.

[169] Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 236.

transmission and distribution networks.[170] The Authority notes that the AER has consistently used an equity beta of 0.8 in all its regulatory decisions after the 2009 WACC Review.

The Authority also adopted an equity beta of 0.8 for its recent Final Decision on Western Australia Gas Networks in February 2011 and also for its Draft Decision on Dampier Bunbury National Gas Pipeline in March 2011.

In addition, the Authority conducted a search from Bloomberg's terminal for the current values of equity beta, including raw beta[171] and beta[172], for Australian utilities companies. It is noted that there are no constraints on the search criteria: all Australian utilities companies are selected.

From Table 9.5 below, the raw equity beta and the equity (adjusted) beta for all 29 companies in the sample are 0.29 and 0.53, respectively.

In its 2009 WACC review for electricity transmission and distribution network service providers, with the assistance of Associate Professor Henry of the University of Melbourne, the AER established a sample of Australian businesses, comprising gas-only network businesses, one electricity-only network business, network businesses active in both electricity and gas, and general utility businesses. Given the limitations of available Australian data, the AER considered that gas network businesses could be considered as reasonable but not perfect comparators to electricity network businesses, given that both industries involve the transportation of energy.[173]

The Authority notes that the AER has consistently used an equity beta of 0.8 in all its regulatory decisions after the 2009 WACC Review.

[170] See for example: Australian Energy Regulator 2009-10, Final decision: WACC review, May 2009; Jemena: Access arrangement proposal for the NSW gas networks 1 July 2010 – 30 June 2015 (Final Decision, May 2010).

[171] Volatility measure of the percentage price change of the security given a one percent change in a representative market index. The beta value is determined by comparing the price movements of the security and the representative market index for the past two years of weekly data.

[172] Estimate of a security's future beta. This is an adjusted beta derived from the past two years of weekly data, but modified by the assumption that a security's beta moves toward the market average over time. The formula used to adjust beta is :

Adjusted Beta = (0.66666) * Raw Beta + (0.33333) * 1.0

[173] The main sample consisted of: AGL (2002 to 2005); Alinta (2002 and 2007); Alinta Network Holdings Pty Ltd (2003 to 2006); Country Energy (2002 to 2006); Diversified Utility and Energy Trusts (2003 to 2008) ; ElectraNet Pty Ltd (2002 to 2008); Energy Australia (2002 to 2006); Envestra Ltd (2002 to 2008); Ergon Energy Corporation (2002 to 2008); ETSA Utilities (2002 to 2008); GasNet Australia (Operations) Pty Ltd (2002 to 2007); Integral Energy (2002 to 2006); SP AusNet Group (2006 to 2008), and SPI PowerNet Pty Ltd (2002 to 2005)

Table 9.5 Equity beta of Australian utilities as at March 2011

	Ticker	Company Name	Beta	Raw Beta
1	WHN AU Equity	WHL ENERGY LTD	3.99	5.48
2	TEY AU Equity	TORRENS ENERGY	1.44	1.66
3	ORG AU Equity	ORIGIN ENERGY	1.23	1.35
4	HRL AU Equity	HOT ROCK LTD	1.20	1.30
5	ENV AU Equity	ENVESTRA LTD	1.17	1.25
6	IFN AU Equity	INFIGEN ENERGY	1.00	1.00
7	GDY AU Equity	GEODYNAMICS LTD	0.93	0.89
8	GRK AU Equity	GREEN ROCK ENERG	0.92	0.88
9	EVM AU Equity	ENVIROMISSION	0.82	0.74
10	SPN AU Equity	SP AUSNET	0.82	0.73
11	ISK AU Equity	ISLAND SKY AUSTR	0.70	0.56
12	SKI AU Equity	SPARK INFRASTRUC	0.69	0.54
13	GER AU Equity	GREENEARTH ENERG	0.63	0.44
14	AGK AU Equity	AGL ENERGY LTD	0.58	0.36
15	AEB AU Equity	ALGAE.TEC LTD	0.49	0.23
16	EOL AU Equity	ENERGY ONE LTD	0.43	0.15
17	ENE AU Equity	ENERGY DEVEL	0.26	-0.11
18	PEA AU Equity	PACIFIC ENERGY	0.25	-0.12
19	ENB AU Equity	ENEABBA GAS LTD	0.21	-0.18
20	TSN AU Equity	TRANSACTION SOLU	0.21	-0.19
21	APK AU Equity	AUSTRALIAN POWER	0.16	-0.26
22	EWC AU Equity	ENERGY WORLD COR	0.14	-0.29
23	GHT AU Equity	GEOTHERMAL RESOU	0.12	-0.32
24	AEJ AU Equity	ALINTA ENERGY LT	0.09	-0.36
25	VIR AU Equity	VIRIDIS CLEAN EN	-0.11	-0.67
26	TSI AU Equity	TRANSFIELD SERVI	-0.15	-0.72
27	EPW AU Equity	ERM POWER LTD	-0.45	-1.18
28	GNB AU Equity	GREENBOX GROUP L	-0.49	-1.23
29	ERJ AU Equity	ENERJI LTD	-2.06	-3.59
		Sample Average	**0.53**	**0.29**

Source: Bloomberg and Economic Regulation Authority.

After considering all the available evidence, the Authority is of the view that an equity beta of 0.7 is appropriate for Horizon Power.

9.4 Final WACC parameters

The input parameters to calculate a benchmark rate of return for Horizon Power for the purposes of this inquiry are shown in Table 9.6 below. This results in a real pre-tax WACC of 7.23 per cent.

Table 9.6 Final report - Parameter values for determination of a rate of return as at 28 February 2011 (Per cent)

Parameter	Value (Per cent)
Nominal Risk Free Rate (R_f)	5.71
Real Risk Free Rate (R_f^r)	3.06
Inflation Rate π_e	2.57
Debt Proportion (D)	60
Equity Proportion (E)	40
Cost of Debt: Debt Risk Premium (DRP) (BBB+)	3.124
Cost of Debt: Debt Issuing Cost (DIC)	0.125
Cost of Debt: Risk Margin (RM)	3.249
Australian Market Risk Premium (MRP)	6
Equity Beta (β_e)	70
Corporate Tax Rate (T_c)	30
Franking Credit (γ)	53
Nominal Cost of Debt (R_d^n)	9.0
Real Cost of Debt (R_d^r)	6.23
Nominal Pre Tax Cost of Equity $(R_e^{n,\text{pre-tax}})$	11.54
Real Pre Tax Cost of Equity $(R_e^{r,\text{pre-tax}})$	8.74
Nominal After Tax Cost of Equity $(R_e^{n,\text{post-tax}})$	9.91
Real After Tax Cost of Equity $(R_e^{r,\text{post-tax}})$	7.16

Source: ERA analysis

Inputting the parameters shown above into the WACC equation results in the pre-tax WACC values shown in Table 9.7 below.

The Authority is aware that the benchmark WACC for Horizon Power in the final report is a different value compared to the commercial WACC calculated in the Proposed Revised Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline (**DBNGP**) – Draft Decision.

This results from the timing of the publication of the final report for Horizon Power. The Draft Decision for DBNGP is consistent with the five year term for the risk free rate proposed by the Authority's recent discussion paper on calculating the debt risk premium. Furthermore, the publication of the Draft Decision enables public debate on the use of a five year term for the risk free rate. However, the draft report for Horizon Power was published prior to the Authority's discussion paper on the debt risk premium and so calculates the risk free rate over a 10 year term in line with the Authority's previous approach. To ensure consistency and transparency between the draft and final reports for Horizon Power a 10 year term for the risk free rate has been retained in this final report.

Table 9.7 Final report – the Authority's revised recommendation on WACC for Horizon Power (per cent)

WACC	Value
Nominal pre tax WACC $\left(WACC_n^{\text{pre-tax}}\right)$	9.99%
Real Pre Tax WACC $\left(WACC_r^{\text{pre-tax}}\right)$	7.23%

Source: ERA analysis

The Authority's final recommendations on return on capital for Horizon Power are shown below.

9.5 Final recommendations

9) A real pre tax benchmark WACC of 7.23 per cent be used for the calculation of cost-reflective tariffs for the review period. This ensures the calculated tariffs reflect the efficient cost of supplying electricity to regional Western Australia assuming a competitive electricity market.

10) A real pre tax alternative WACC of 5.77 per cent reflecting Horizon Power's actual cost of debt be used for determining cost of service and hence TEC levels in this inquiry. This ensures that Horizon Power's actual cost of borrowing is reflected in the derived TEC.

10 Cost of Service Model

This section provides background information on how the cost of service was calculated for Horizon Power. The inputs to the cost of service modelling, such as operating and capital expenditure forecasts, the return on capital and the valuation of Horizon Power's asset base are explained in earlier sections of this report. The cost of service calculation for Horizon Power is shown in section 10.2 below.

10.1 Background

The cost of service model is used to calculate the revenue requirement for an efficient regional power corporation. The revenue requirement is determined by the sum of return on capital, return of capital (depreciation) and efficient operating costs. The calculation of the amount of each of these three elements is as follows:

- return on capital – regulatory asset base, net of depreciation multiplied by the rate of return, where;
  - the regulatory asset base is the initial capital base at 1 July 2009 (as determined in section 6) rolled forward by net, new, self-funded efficient capital additions (as determined in section 8); and
  - the rate of return as determined in section 9;
- return of capital – depreciation is calculated on the regulatory asset base, which is, in turn, calculated as straight-line depreciation on;
  - the initial capital base utilising remaining weighted asset lives per asset class; and
  - new capital additions utilising asset lives per asset class in line with the Horizon Power's Fact Sheet No. 38 – Asset Classes and Asset Life Expectancy; and
- efficient operating expenditure as determined in section 7.

10.2 Cost of service – final report

The final report calculates two costs of service profiles for Horizon Power. These are based on:

- Horizon Power's requested inputs; and
- using the Authority's revised recommended inputs.

The following inputs vary between the two scenarios. These are as follows:

Table 10.1 Comparison of input data – Horizon Power forecasts against ERA recommended forecasts

Input	Horizon Power requested	ERA recommended
Initial capital base ($m real at 30/6/2009) - section 6.3	747.4	388.7
WACC – real pre tax return on capital (%) - section 9.3	8.88	7.23
Total operating costs over the review period ($m real at 30/6/2009) - section 7	1,691.8	1,574.1
Total capital expenditure over the review period ($m real at 30/6/2009) - section 8	841.6	798.2

Source: ERA analysis

The costs of service that result from the two scenarios are shown in Table 10.2 below.

Table 10.2 Final report – comparison of cost of service for Horizon Power using ERA recommended forecast inputs ($m real at 30/6/2009)

	2010	2011	2012	2013	2014
Cost of service – Horizon Power inputs	376.5	440.0	487.8	562.1	549.2
Cost of service – ERA recommended inputs	**325.2**	**371.5**	**408.0**	**431.8**	**447.1**
Reduction	-51.3	-68.5	-79.8	-130.3	-102.1
As a percentage	*-13.6%*	*-15.6%*	*-16.4%*	*-23.2%*	*-18.6%*

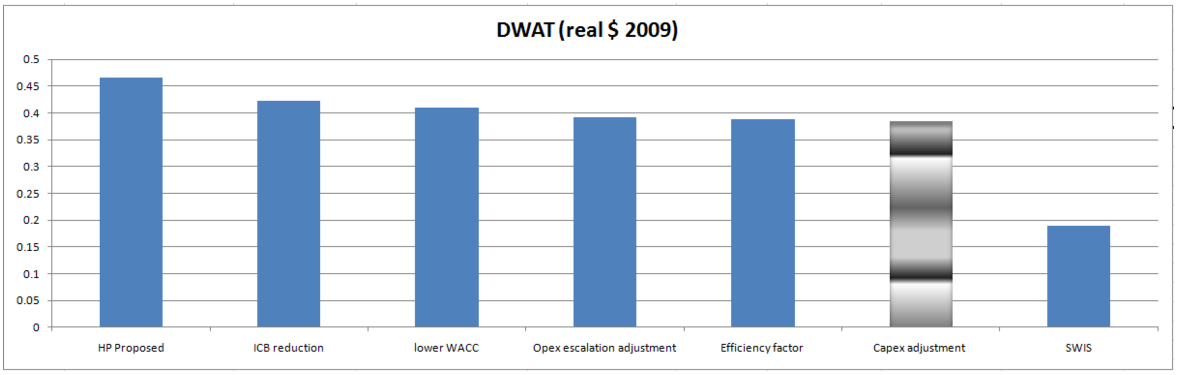
Source: ERA analysis

The cost of service based on the Authority's revised recommended forecast inputs is much lower than the cost of service calculated from Horizon Power's forecast inputs. This is a result of the various adjustments the Authority is recommending should be made to Horizon Power's forecast input data to better reflect the inputs of an efficient regional service provider.

A simple way to demonstrate these adjustments is to compare the Discounted Weighted Average Tariff (**DWAT**) that results from each adjustment as it is made. The DWAT divides the discounted cost of service from the regulatory model (from each scenario) by the discounted kWh over the five year review period.

The effect on the DWAT of the various input adjustments made by the Authority in the final report is shown in Figure 11.3 below and compared to the equivalent figure for the SWIS.

Figure 10.1 Final report – the incremental effect of Authority's proposed reductions on DWAT



Source: ERA analysis

Overall, the Authority has reduced average cost-reflective tariffs by $0.0861 per kWh, from $0.4659 per kWh down to $0.3843 per kWh. The comparative figure for the SWIS is $0.19 per kWh. The average cost-reflective tariff for Horizon Power as a whole is shown by the graduated bar above.

The average tariff reduction mainly results from reducing Horizon Power's asset valuation (-$0.0443), applying a lower return on capital (-$0.0112), applying a lower escalation factor (-$0.0195) and efficiency target (-$0.0020) to Horizon Power's level of efficient operating costs and reducing Horizon Power's forecast capital expenditure to efficient levels (-$0.0046).

The one per cent efficiency adjustments to the controllable 2009/10 base operating year cost was applied uniformly across the individual towns, district and Bentley offices. However, to achieve the required operating cost savings, Horizon Power can seek to achieve the efficiency gains in whatever way it chooses. Consequently the actual DWAT may vary from those shown in Figure 10.1 above.

10.5.1 Financial implications of the cost of service for Horizon Power

In the final report the Authority revised two of its modelling assumptions, which are as follows:

- The Authority has assumed that a prudent regional service provider would be expected to pay a dividend and repay its debt going forward. Consequently, the Authority has included a 50 per cent dividend assumption from 2011/2012 and a repayment of debt principal from 2009/10.
- The Authority has decided to treat the finance lease as an operating lease in determining the cost of service for Horizon Power.[174]

[174] In its statutory accounts Horizon Power classifies its finance leases in accordance with Australian Accounting Standard Board (AASB 117) Leases. In this treatment finance leases are included as assets in its balance sheet with a corresponding amount included as interest bearing liabilities. By the Authority treating finance leases as an operating lease an allowance is made in Horizon Power's operating costs to cover the interest payments required by the finance lease, effectively treating them as another operating cost. This additional operating cost is recovered through the cost of service which is carried forward to the modelled statutory accounts. Therefore Horizon Power has a sufficient allowance in its cost of service to meet its interest payments. However, the finance lease has otherwise been completely excluded from the modelled statutory accounts. This is because the finance lease is not recognised as an asset under

The key financial indicators resulting from the Authority's revised recommended inputs and revised assumptions are shown in Table 10.3 below.

Table 10.3 Final report − Key financial indicators for Horizon Power using ERA recommended inputs ($m nominal unless otherwise stated)

	2010	2011	2012	2013	2014
Net profit	35.8	38.3	32.1	40.2	44.9
Interest bearing liabilities	276.6	454.3	574.2	698.2	695.2
Net assets	180.6	282.5	360.5	398.8	425.4
Total asset	572.0	850.1	1,048.1	1,210.3	1,234.0
Interest bearing liabilities/Total assets	48.4%	53.4%	54.8%	57.7%	56.3%
Net cash from operating activities	46.4	45.0	63.9	79.5	88.4
Gearing	68.4%	66.8%	65.6%	67.0%	65.5%

Source: ERA analysis

The Authority's recommendations result in positive net profit figures across all years in the review period and a gearing ratio trending toward the standard 60:40 (debt to equity) gearing ratio assumed by economic regulators for a benchmark service provider.

The Authority has also reviewed Horizon Power's investment credit rating using two investment rating approaches: Standard and Poors (S&P)[175] and IPARTs regulatory investment approach for government utility businesses.[176] These rating systems assess the creditworthiness of a business as an indicator of the business's ability to raise finance for its investments.

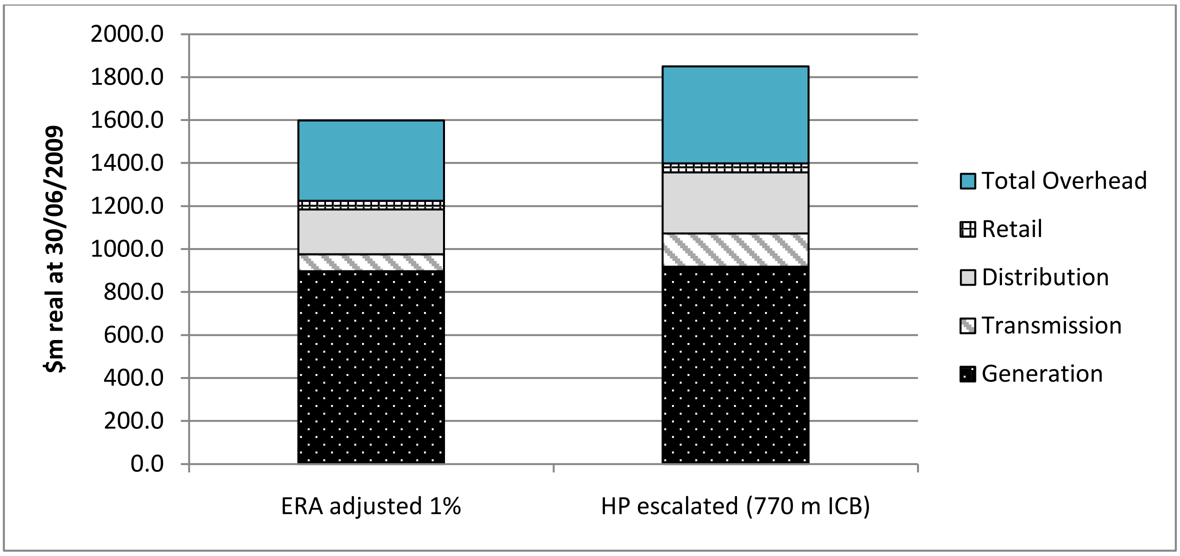
Under the S&P credit rating criteria Horizon Power rates at BBB in 2009/10 which represents investment grade. Under the IPART credit rating criteria Horizon Power rates at A+/A across the majority of the review period.

regulatory methodology (as Horizon Power does not own the asset). By treating the finance lease in this way the gearing showing in the final report reflects the financial position of the company without the impact of the finance lease.

[175] Standard and Poors (2011), Corporate Ratings Criteria – update February 2011

[176] IPART (2011), Financeability tests and their role in price regulation

Figure 10.2 Final report – NPV comparison of the functional analysis under the two different scenarios (i) using Horizon Power proposed inputs and (ii) ERA recommended inputs ($m real at 30/6/2009)



Source: ERA analysis

The contribution of each functional area to the cost of service is shown in Figure 10.2 above.

The contribution of each function to the cost of service for Horizon Power as a whole under each of the two scenarios is shown above and the equivalent (normalised) analysis for each town is given in Appendix G. In the final report, the NPV of the ERA adjusted cost of service under Horizon Power's assumptions was $1,849.7 (real at 30/6/2009) while the corresponding figure under the ERA recommendations was $1,599.1m (real at 30/6/2009).

The dominance of generation and total overhead occurs in both scenarios but the NPV of the ERA cost of service was lower by $250.6m (real as at 30/6/2009) in the final report. Reductions were shown in all cost functions because the one per cent efficiency adjustment was applied consistently to all controllable operating costs.

11 Cost-Reflective Tariffs

The Terms of Reference requires the Authority to determine cost-reflective retail tariffs for the review period for each of the retail tariffs currently provided by Horizon Power. The issues paper for the inquiry also discussed cost-reflective tariff design.[177] However, the quantity and quality of data reviewed in preparing the draft and final reports necessitated a more simplified approach to the derivation of cost-reflective tariffs for the inquiry. The Authority has calculated a simplified average tariff for each system, for Horizon Power in aggregate and also a NWIS and non-NWIS average tariff.

This section provides background information on the simplified average tariff was calculated for Horizon Power in the final report (section 11.2).

11.1 Background

One representation of a cost-reflective tariff is the Discounted Weighted Average Tariff (DWAT) as this divides the discounted cost of service from the regulatory model by the discounted kWh over the five year review period. The simple DWAT is a combination of direct town costs of service plus district and head office overheads allocated to each town by the appropriate amount of electricity sent out to each town/system as measured by kWh.

11.2 DWAT – final report

In the final report the Authority has calculated DWATs for all towns, the NWIS and for Horizon Power as a whole.

Horizon Power's aggregate DWAT is shown in Table 11.1 below compared to the one calculated using Horizon Power's forecast inputs.

Table 11.1 Comparison of aggregated DWATs for Horizon Power ($ real at 30/6/2009)

DWAT comparison	Horizon Power's original forecasts	Final report ERA recommendations
DWAT ($ per kWh)	0.4659	0.3843
Difference		-0.0816
As a percentage		*-17.5%*

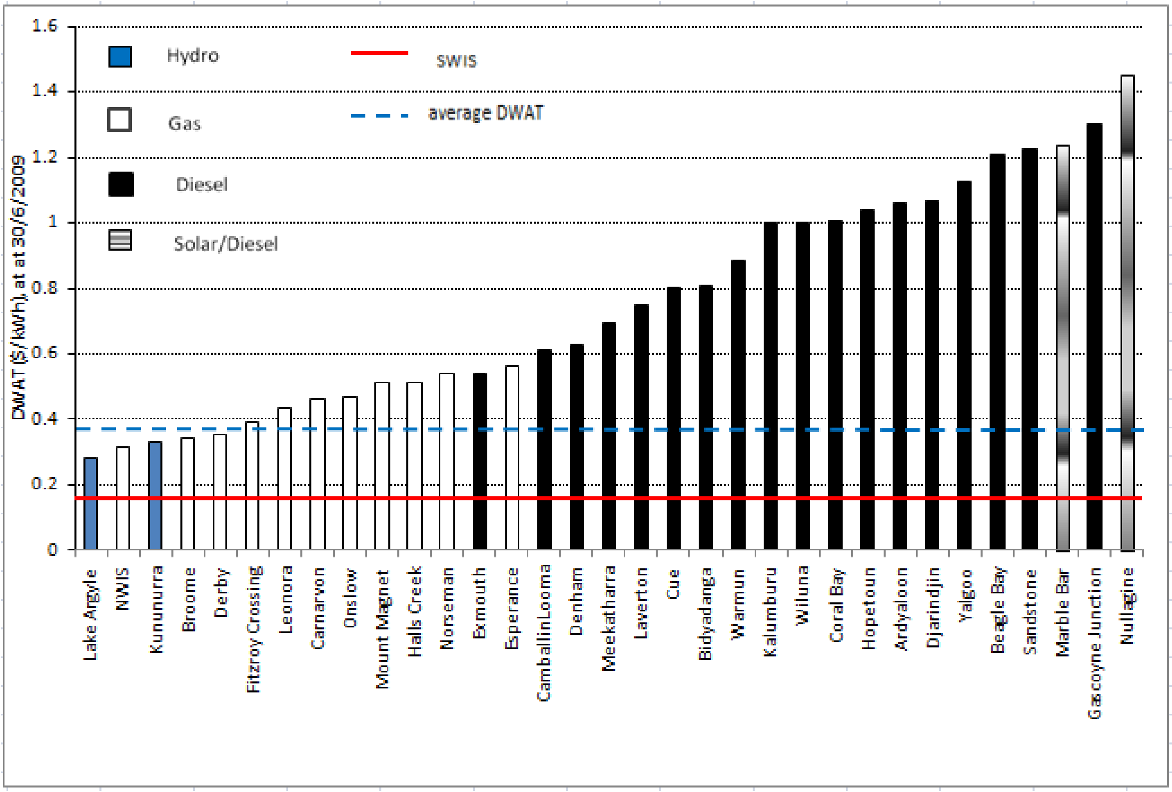
Source: ERA analysis

The Authority has listed the DWAT for all towns and placed these in ascending order in Figure 11.1 and added the aggregate DWAT for Horizon Power and the equivalent figure for the SWIS.

The DWATs range from $0.2829 for Lake Argyle in the East Kimberley to $1.4556 for Nullagine in the Pilbara. The aggregate for Horizon Power as a whole is $0.3843 and the equivalent figure for the SWIS is $0.19. As all DWATs for Horizon Power systems are higher than the SWIS figure this means that all distribution systems are effectively subsidised.

[177] Economic Regulation Authority (2010), Inquiry into the Funding Arrangements of Horizon Power: Issues Paper, p18

Figure 11.1 Final report – simple DWAT by town (ERA recommended inputs) ($/kWh)



Source: ERA analysis

In the final report the Authority noted reasonably strong relationships between the DWAT for a town and:

- the type of fuel used to generate electricity – hydro is the least expensive source[178] (as evidenced by Lake Argyle, Wyndham and Kununurra at the low end in the above figure), followed by gas (used in towns such as Broome, Derby and Esperance), then diesel only (a fairly wide range from Onslow to Menzies), then solar and diesel combined (Marble Bar and Nullagine);
- generator capacity – the larger the generation capacity the lower the cost to supply (the NWIS has the largest installed capacity and a low DWAT compared to towns such as Gascoyne Junction, Menzies, Yalgoo and Ardyaloon, which have installed capacity at less than 1MW); and
- distance from infrastructure – in particular for diesel generators, as the further away a town is from a major town the higher the diesel transport costs (as evidenced by the higher costs of supplying more remote towns such as Ardyaloon, Djarindjin and Beagle Bay in the West Kimberley).

12 Tariff Equalisation Contribution (TEC)

This section provides background information on the TEC and then reports the calculated TEC values over the review period using:

[178] However, this is due to the large government subsidy for the construction of Lake Argyle, so this should not be taken as a general repeatable result.

- Horizon Power's cost of service calculated using its forecast operating and capital expenditures, proposed WACC and ICB asset value; and
- Horizon Power's cost of service calculated using the Authority's recommended efficient levels of operating and capital expenditures, WACC and ICB asset value.

This exercise is repeated using both the benchmark and alternative WACC values discussed in section 9 to determine the additional amount included in the balancing revenue item resulting from using a benchmark WACC to calculate Horizon Power's cost of service compared to an alternative WACC based on its actual cost of borrowing.

The Authority suggested two recommendations regarding TEC in the draft report. The public submissions that commented on these recommendations are summarised in section 12.6.2. The Authority then recalculates TEC values for Horizon Power based on the revisions to input data made after the draft report and comments on these values in section 12.6.7.

12.1 Background

The unit cost of supplying electricity to people living in remote areas, outside the South West, is high because of specific operating circumstances associated with these regions. The Government's uniform tariff policy however, ensures that all residential and small business customers pay the same electricity tariffs regardless of where they live. The electricity tariffs of customers living in remote Western Australia are subsidised by taxpayers and South West electricity network customers. This subsidy takes two forms: CSO payments and the TEC.

CSO payments cover the funding of specific projects or programmes, such as the Aboriginal and Remote Community Power Supply Project or rebate schemes for specific groups of customers. Horizon Power and Synergy also currently receive a CSO payment to cover the revenue shortfall arising from the transition of existing tariff levels to cost-reflective tariffs levels in the SWIS.

The shortfall between the income Horizon Power receives from the sum of its existing income sources (e.g. uniform tariff revenue, commercial customer revenue, non-regulated revenue and gifted cash in the form of CSO payments) and the cost-reflective revenue requirement as determined from the regulatory modelling above will inform the level of the TEC set by the State Government.

Horizon Power informed the Authority that it was engaged by the Department of Treasury and Finance and Office of Energy in September 2009 to set TEC for the 2009/10 year and the following two financial years.[179] Horizon Power advised the Authority that the TEC was calculated from projected notional profit after tax and a capital charge.

For the final report, the Authority has used the efficient level of inputs and costs it has determined to calculate the overall revenue required by Horizon Power to perform its functions at the required levels of service. From this total revenue requirement, uniform tariff revenue and commercial customer revenue were deducted to leave a 'balancing revenue' item equivalent to the TEC and CSO.

[179] Horizon Power (2010), Powerpoint presentation to ERA Secretariat

TEC based on Horizon Power's forecast inputs

The Authority took the revenue requirement determined in by using Horizon Power's forecast inputs (see section 10.2 above), converted it to nominal prices and then deducted Horizon Power's income.

This determines the 'balancing revenue' from which Horizon Power's TEC subsidy is derived. This is shown in Table 12.1 below.

Table 12.1 Derivation of the 'balancing revenue' item and TEC ($ nominal) using Horizon Power's forecast inputs

Balancing revenue calculation	2010	2011	2012	2013	2014
Cost of service	386.2	463.0	526.4	622.2	623.5
Commercial customer revenue (Tier 3&4)[180]	-18.3	-29.6	-28.0	-26.2	-26.8
Unit tariff revenue (Tier 1&2)	-152.5	-182.2	-222.0	-241.5	-265.2
Required 'balancing revenue'	215.4	251.2	276.4	354.5	331.5
Net CSO	-35.7	-31.8	-22.8	-22.2	-22.3
Derived TEC	**179.7**	**219.4**	**253.6**	**332.2**	**309.2**

Source: ERA analysis. Numbers may not add due to rounding.

The Table 12.2 compares the derived TEC value, determined from Horizon Power's proposed forecasts, with the gazetted TEC values for 2009/10 to 2013/14.

The NPV of the gazetted TEC figures is $397.7m (real at 30/6/2009) for year 2009/10 to 2011/12. The comparable NPV over the same three years from Table 12.2 is $518.0m (real as at 30/6/2009) an increase of $120.3m (real NPV as at 30/6/2009).

Table 12.2 Comparison of derived TEC (Horizon Power's forecast cost inputs) with gazetted TEC ($m nominal)

Item	2010	2011	2012	2013	2014
Gazetted TEC	122.1	175.7	181.2	n/a	n/a
Derived TEC - Horizon Power's forecast inputs	179.7	219.4	253.6	332.2	309.2

Source: Government Gazette No. 153, 25 August 2009, p3325 and Government Gazette No. 208, 17 November 2010, p4639 and ERA analysis.

The derived TEC determined by the financial modelling using Horizon Power's inputs in the final report is considerably higher than the current gazetted TEC figures. This results from the influence of the following items:

- a higher asset base − in the last gazetted TEC calculation Horizon Power used an average asset value of $452m (nominal). The asset base valuation determined by Horizon Power using a depreciated replacement valuation approach is $747.7m (real at 30/6/2009);
- different depreciation charges – any difference in the value of the asset base will also result in a different depreciation charge from that which was used to calculate

[180] Tier 3 and 4 related to different pricing schemes for Horizon Power's contestable commercial customers.

the gazetted TEC and the depreciation charge calculated by Horizon Power in its calculation of its depreciated replacement valuation; and

- a higher operating cost value – at the time the gazetted TEC was calculated Horizon Power only had budgeted operating costs available ($300m nominal). In the calculations for the final report, the Authority used Horizon Power submitted actual operating costs information for 2009/10 of $347.6 (nominal). As operating costs are the main driver of the overall cost of service, higher operating costs increase the balancing revenue item and resulted in a higher overall TEC requirement.

TEC based on the Authority's final recommendations

The process has been repeated but using the cost efficient revenue requirement based on:

- the Authority's revised recommended levels of operating and capital costs;
- the inflation-adjusted historical cost ICB value; and
- the updated benchmark WACC.

At the consolidated level, the derived TEC that resulted from the ERA revised recommended revenue requirement less Horizon Power's forecast income is also shown compared to the gazetted TEC in Table 12.2 above.

Table 12.3 Final report − derivation of the 'balancing revenue' item and TEC ($ nominal) using ERA recommended forecasts

Balancing revenue calculation	2010	2011	2012	2013	2014
Cost of service	333.5	390.8	440.3	477.9	507.6
Commercial customer revenue (Tier 3&4)	-18.2	-29.6	-28.0	-26.2	-26.8
Unit tariff revenue (Tier 1&2)	-152.5	-182.2	-222.0	-241.5	-265.2
Required 'balancing revenue'	162.8	179.0	190.3	210.2	215.6
Net CSO	-35.7	-31.8	-22.8	-22.2	-22.3
Derived TEC	**127.1**	**147.2**	**167.5**	**188.0**	**193.3**

Source: ERA analysis. Numbers may not add due to rounding.

The balancing revenue figure and hence derived TEC was reduced when using the Authority's revised recommended forecasts to calculate the efficient cost of service. This was predominantly because of:

- the Authority's recommended reductions to operating costs in the final report ($72.6m real as at 30/6/2009); and
- the Authority's recommended reductions to capital expenditure in the final report ($43.4m real as at 30/6/2009).

Table 12.4 Final report – comparison of derived TEC (ERA recommended forecasts) with gazetted TEC ($m nominal)

Item	2010	2011	2012	2013	2014
Gazetted TEC	122.1	175.7	181.2	n/a	n/a
Derived TEC - adjusted 09/10 base year and ERA recommended forecasts	127.1	147.2	167.5	188.0	193.3

Source: ERA analysis

Table 12.4 compares the derived TEC, determined from the ERA proposed forecasts in the final report, with the gazetted TEC values for 2009/10 to 2011/12.

The NPV of the TEC from the ERA final report scenario is $363.1m (real as at 30/6/2009) for years 2009/10 to 2011/12, a reduction of $34.6m (real as at 30/6/2009) when compared to the NPV of the gazetted TEC of $397.7m (calculated over the same three years).

This greater reduction in the TEC (from the ERA recommended inputs compared to Horizon Power's forecast inputs) largely resulted from the one per cent compounding efficiency factor applied to the base year controllable unit operating costs per connection of Horizon Power. This resulted in a reduction in Horizon Power's total operating cost of $72.6m (real as at 30/6/2009) over the review period.

Operating costs are the major contributor to the cost of service and revenue requirement. Therefore, if operating costs are reduced then the cost of service reduces and less funding is required to be met by the TEC.

TEC based on an alternative WACC

Section 9 outlines the potential impact upon the derived TEC of using a benchmark WACC or an alternative WACC based on Horizon Power's actual borrowing costs. The results of that comparison are shown in Table 12.5 below.

Table 12.5 Final report – comparison of derived TEC with ERA revised forecasts but using a benchmark WACC and alternative WACC ($m nominal)

Item	2010	2011	2012	2013	2014
Derived TEC - calculated with benchmark WACC (7.23%)	127.1	147.2	167.5	188.0	193.3
Derived TEC - calculated with alternative WACC (5.77%)	121.3	140.0	156.3	173.7	176.4
Variation	-5.8	-7.2	-11.2	-14.3	-16.9

Source: ERA analysis. Numbers may not add due to rounding.

Table 12.5 shows that the application of an alternative WACC (based on Horizon Power's borrowing from the State Government at favourable rates) will result in a reduction on the TEC compared to when a (higher) benchmark WACC is used. Over the review period this would amount to a $15.7m (nominal) reduction in the net present value of TEC.

The main causes for concern with the current funding of TEC though network charges in the SWIS are that:

- the funding of the TEC subsidy rests with a specific group of electricity customers instead of being funded by all Western Australian consumers via general taxation;
- the inclusion of the TEC in SWIS distribution network prices distorts prices in those areas of the SWIS that are competitive;
- by limiting the funding of the TEC subsidy to a subset of electricity consumers this effectively inhibits timeline to achieve fully cost-reflective pricing within the SWIS;
- the subsidies received by Horizon Power are not transparent; and
- it is inconsistent with how other utilities are subsidised.

Therefore, in the draft report the Authority recommended that the TEC should be funded by a CSO payment directly to Horizon Power.

This approach was raised by Alinta Energy and Griffin Energy in their submissions in response to the issues paper. Furthermore, the Office of Energy in its response to the issues paper also encouraged the Authority to:

> "..examine what is an appropriate funding mechanism for Horizon Power, including whether the TEC should be funded through a direct CSO from Government instead of from network tariffs paid by South West consumers."[181]

In the draft report the Authority also noted that the form of funding for the TEC ultimately rests with the Government. However, should the Government continue to fund the TEC though Western Power's network access charges then the Authority considered that this should be reflected in lower distribution network access charges for Western Power so that all Western Power's wholesale customers benefit.

As well as deriving TEC values based on a benchmark WACC and alternative WACC given the Authority's recommended efficient inputs, the Authority also highlighted two separate issues concerning the TEC in the draft report. These are:

- funding the TEC through a CSO payment; and
- lowering distribution network tariffs in the SWIS.

Each of these issues and the public submissions commentary are discussed in turn in the following sections.

12.6.1 Funding TEC through a CSO

The Authority's draft recommendation 9 in the draft report is shown below.

The TEC should be funded by a CSO paid directly to Horizon Power.

12.6.2 Public submissions on the draft report

Of the 17 submissions received in response to the draft report, 11 commented on the above draft recommendation, that the TEC should be funded by a CSO paid directly to Horizon Power. These were the submissions from Horizon Power, the Regional Development Council, the Chamber of Commerce and Industry of Western Australia, WACOSS, the Mid West Development Commission, the Esperance Chamber of Commerce and Industry, the Pilbara Development Commission, Alinta, the Office of

[181] Office of Energy (2010), Submission to the inquiry into the funding arrangements of Horizon Power, Attachment 1, p5

Energy, the Goldfields-Esperance Development Commission and Western Power. All of these submissions are available on the Authority's website.[182]

Horizon Power's submission

Horizon Power's submission commented that the draft recommendation was 'inconsistent with the Terms of Reference' of the inquiry. Horizon Power's main concern is that the business is securely funded to enable it to deliver energy to its customers, consistent with its legislated mandate. Consequently, Horizon Power did not express a view on the mechanism used by Government to generate adequate funding.

Other submissions

Out of the other 10 submissions, all of the submissions received from regional bodies such as the development commissions, supported the continuance of funding from both CSO and TEC sources. The comment from the Pilbara Development Commission is representative of the comments from the other regional bodies:

> "We believe that the current system of funding Horizon Power's revenue shortfall, being made up of a combination of both CSOs and TEC has served the State well, and hence this Commission does not support the recommendation that it be changed to be provided solely by means of a CSO."[183]

Western Power's submission confirmed that it did not support the use of a TEC as this represented:

> "..a substantial cross-subsidy between South West Interconnected Network (**SWIN**) customers and non-SWIN customers which ultimately results in a distortion of the actual cost of electricity."[184]

Western Power is supportive of the Authority's suggestion to replace the TEC with a CSO as this would be funded by all taxpayers in the State and as such, consistent with the provision of subsidies for other essential services.

In its submission the Office of Energy supported in principle the draft recommendation to fund the TEC through a CSO payment.

Alinta strongly supports this draft recommendation. Its submission states that:

> "Requiring electricity customers in the SWIS to fund Horizon Power's losses is at odds with the manner in which the $350 million loss incurred by the Water Corporation in supplying water and wastewater services to consumers in regional and remote Western Australia is funded. In that case, the Government makes a CSO payment from consolidated revenue to the corporation."[185]

Alinta's submission also commented that the current cross-subsidy arrangements 'undermine competition in the SWIS'. This point was also made in the submission from the Chamber of Commerce and Industry of Western Australia which expressed strong support for the draft recommendation. The submission stated:

[182] Economic Regulation Authority website, www.erawa.com.au

[183] Pilbara Development Commission (2011), Submission to the inquiry into the funding arrangements of Horizon Power, p3

[184] Western Power (2011), Submission to draft report on Horizon Power's funding arrangements, p3

[185] Alinta (2011), Inquiry into the funding arrangements of Horizon Power, Attachment, p1

> "..this amendment would decouple the cost of supplying power in the SWIS from the cost of supplying in the regions thereby allowing for fully cost-reflective pricing in the SWIS. This is an important step towards full retail contestability in this market."[186]

In its submission, WACOSS chose to reserve a position on the issue pending the outcome of the State Government's Tariff and Concession Framework Review (**TCF**) which is being conducted by the Office of Energy and WACOSS and will seek to investigate options to improve cost reflectivity arrangements in prices for electricity provision. Consequently, WACOSS suggest that the issue regarding the mechanism for funding Horizon Power be reconsidered after the TCF has been completed toward the end of 2011.[187]

12.6.3 Authority comments

After considering the submissions received in response to the draft report the Authority is mindful of the requests from the regional agencies to maintain the status quo. However, the Authority suggests that other issues arising from funding Horizon Power via the TEC such as cross subsidy and price distortion in the SWIS provide stronger arguments for replacing the TEC with a CSO paid directly to Horizon Power.

In the inquiry the Authority is tasked with determining the efficient costs of supply for a regional power supplier such as Horizon Power. One of the outcomes of the inquiry will be to inform the setting of the size of the subsidy necessary for Horizon Power to provide electricity services across rural Western Australia. The level of subsidy will be aligned with the cost of service for an efficient regional electricity supplier regardless of how the subsidy is funded (TEC and CSO or just CSO). In recommending that the source of the subsidy to Horizon Power is changed from the TEC to a CSO the Authority does not anticipate that any less funding be available for service delivery in the regions.

More importantly, moving to fund the TEC via a CSO has the benefits of:

- lower network tariffs in the SWIS;
- removing price distortion in the competitive markets in the SWIS;
- an earlier timeframe to achieve full retail contestability in the SWIS;
- greater transparency around the overall level of the subsidy for Horizon Power; and
- being consistent with how other utility subsidies are funded.

The Authority's final recommendation is shown below.

[186] Chamber of Commerce and Industry of Western Australia (2011), Inquiry into the funding arrangements of Horizon Power: Draft report, p2

[187] WACOSS (2011), WACOSS submission to the inquiry into the funding arrangements of Horizon Power – Draft Report, pp 5-6

12.6.4 Final recommendation

11) The TEC be funded by a CSO paid directly to Horizon Power. This has the benefits of:

    a) lower distribution network tariffs in the SWIS;

    b) removing price distortion in the competitive markets that exist within the SWIS;

    c) an earlier timeframe to achieve full retail contestability in the SWIS;

    d) greater transparency around the overall level of subsidy for Horizon Power; and

    e) being consistent with how other utilities are subsidised.

12.6.5 Lowering distribution network tariffs in the SWIS

The Authority's draft recommendation 10 in the draft report is shown below.

Should the Government continue to subsidise Horizon Power through a TEC payment funded by SWIS network customers, the lower TEC should be gazetted. This will provide for the lower TEC to be passed through to lower distribution network tariffs in the SWIS.

12.6.6 Public submissions on the draft report

Three of the submissions received in response to the draft report commented on this draft recommendation (Western Power, Alinta and the Chamber of Commerce and Industry of Western Australia). All of these submissions are published on the Authority's website.[188]

Horizon Power submission

Horizon Power did not expressly comment on this draft recommendation other than to confirm that the business need to be 'securely funded' to ensure it can continue to provide safe and reliable energy to regional Western Australia.

Other submissions

Western Power's submission reiterated that it does not support the use of a TEC but that if this funding mechanism is retained it should be based on the 'net cost to government'. Western Power is also concerned that a potentially lower TEC calculated for 2011/12 would not, given the timing of the inquiry, be gazetted in time to be incorporated into Western Power's 2011/12 price list that is required to be submitted to the Authority by 28 April 2011.

Alinta's submission supported the Authority's draft recommendation as it stands.

[188] Economic Regulation Authority website www.erawa.com.au

The submission from the Chamber of Commerce and Industry of Western Australia noted that any decision to amend the funding arrangements for the TEC needs to 'align with the Government's *Strategic Energy Initiative* which aims to set a broader, long term framework for energy policy' in the State.

12.6.7 Authority comments

The Authority has determined the amount in the TEC payment that is incurred because of the application of a benchmark commercial WACC in the calculation of Horizon Power's cost of service. If the lower TEC is gazetted as in the Authority's draft recommendation 10 then this will leave the variance between the TEC calculated using the benchmark WACC and the TEC calculated using the alternative WACC unfunded: this would be inconsistent with ensuring Horizon Power is financially sound. In this situation the Authority suggests that this difference is funded through an additional subsidy from Government. This is illustrated in Table 12.6 below.

Table 12.6 Comparison of derived TEC values with benchmark and alternative WACCs ($ nominal)

Item		2010	2011	2012	2013	2014
Derived TEC - calculated with benchmark WACC (7.23%)	Funding requirement	127.1	147.2	167.5	188.0	193.3
Derived TEC - calculated with alternative WACC (5.77%)	TEC to be gazetted	121.3	140.0	156.3	173.7	176.4
Variation	Additional subsidy	5.8	7.2	11.2	14.3	16.9

Source: ERA analysis

This additional suggestion for an additional subsidy to fund the shortfall in derived TEC resulting from the use of an alternative WACC based on Horizon Power's actual cost of borrowing necessitates a slight change to the draft recommendation 10. The Authority's final recommendation on this issue is shown below.

12.6.8 Final recommendation

12) Should the Government continue to subsidise Horizon Power through a TEC payment funded by SWIS network customers, the lower TEC be gazetted. This will provide for the lower TEC to be passed through to lower distribution network tariffs in the SWIS. The shortfall in TEC could be funded through an additional Government subsidy.

13 The Future Regulatory Approach

This section discusses the benefits of having a second inquiry into the funding arrangements of Horizon Power in three years' time.

13.1 Background

The inquiry into the funding arrangements of Horizon Power provides the first independent comprehensive assessment of Horizon Power's operating efficiency. The assumptions and recommendations drawn in the draft report were based on data that the Authority had some concerns about, in terms of its accuracy and consistency).

In the Authority's experience it takes time for a company to adapt to the data requirements associated with economic regulation and the level of supporting information required by a regulator when analysing operating and capital expenditure. Consequently, in the draft report, the Authority recommended that a second inquiry be undertaken in three years' time.

Horizon Power has recently changed its chart of accounts to forecast and more correctly allocate data to the town level. Therefore, for the second review there will be several years of actual data available at required level of detail for the Authority to better investigate trends in expenditure and performance.

A second or ongoing series of inquiries enables the Authority to make corrections for any incorrect assumptions made at the previous review. For example, if, when reviewing actual costs, Horizon Power has been faced with inflation greater than CPI inflation, the Authority can consider adjusting for this in a subsequent inquiry, if the expenditure is deemed efficient.

Furthermore, at a later review the Authority would be able to review Horizon Power's demand forecasting performance. If this were to result in Horizon Power having received more or less of a subsidy than necessary, the additional subsidy could be recouped or reimbursed in future periods.

Horizon Power publishes service performance data annually, which is also reviewed by the Authority as part of its licensing functions. By incorporating the review of service standards into subsequent Horizon Power inquiries this enables the Authority to compare historical service performance data and use this to set service standard benchmarks against which Horizon Power's future performance is measured. This, in turn, introduces the opportunity for incentive mechanisms, related to service performance, to be incorporated into the inquiry recommendations. Such incentive mechanisms would compare over or under performance against an agreed benchmark and rewards and penalties could be determined, such as is the case for Western Power.

In the draft report the Authority commented that the setting of incentive mechanisms was inappropriate at this time. This was because retail tariffs to customers are already subsidised and Horizon Power does not predominantly operate in a commercial environment. Furthermore, the Authority prefers that the data quality and consistency issues be resolved before they are used to set incentives.

The Authority made one recommendation in the draft report concerning the regulatory approach in the future as listed below.

A second inquiry into the funding arrangements of Horizon Power be undertaken in three years time to further review Horizon Power's actual costs and to set new efficiency targets.

13.2 Public submissions on the draft report

The Authority received four submissions that commented on the recommendation to hold a subsequent inquiry in three years' time (Horizon Power, the Office of Energy, Alinta and the Chamber of Commerce and Industry of Western Australia). All of these submissions are available on the Authority's website.[189]

13.2.1 Horizon Power submission

Horizon Power's submission was not directly supportive of a second inquiry. Instead the submission stated that it was Horizon Power's preference to:

> "..work with its key stakeholders, including the OOE, DTF and the Minister to develop these arrangements which will position the business to more efficiently deliver against its mandate into the future."[190]

However, Horizon Power did note in its submission that the cost of the present inquiry to date was in the order of $1.1 million (nominal).[191]

13.2.2 Other submissions

All three of the other submissions were supportive of a subsequent inquiry into the funding arrangements of Horizon Power. The Office of Energy's submission stated:

> "The OOE supports a second inquiry into Horizon to be undertaken in three years time to further review Horizon Power's actual costs, the impacts of the first inquiry and consider new efficiency targets with an increased knowledge of Horizon Power's operations."[192]

The submission from the Chamber of Commerce and Industry suggested that if the Government wished to maintain a uniform tariff policy across the State then it was important to accurately take into account the efficient costs of servicing regional areas. It was on this basis that the Chamber of Commerce and Industry supported the draft recommendation.

Whilst in support of a further inquiry in three years' time, Alinta's submission suggested that:

> "the approach adopted by the Authority for future inquiries might be strengthened by requiring that Horizon Power undertake the following steps or processes.
>
> - Establish an optimised regulatory asset base, using the Depreciated Optimised Replacement Cost (DORC) valuation method
> - Conduct more robust top-down demand forecasting

[189] Economic Regulation Authority website, www.erawa.com.au

[190] Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, p49

[191] Horizon Power (2011), Horizon Power (2011), Horizon Power's submission to the inquiry into the funding arrangements of Horizon Power, Schedule B, response reference number 53

[192] Office of Energy (2011), Office of Energy's submission on the draft report for the inquiry into the funding arrangements of Horizon Power, Attachment 1, p4

- A detailed ex-ante capital programme itemised by regulatory category
- More detailed scheme based tariff calculations, including greater level of transparency around the allocation of corporate costs"[193]

13.3 Authority comments

As explained in the draft report, the Authority recommends that a second inquiry be undertaken in three years' time, as by then Horizon Power would have actual cost information available at the required level of detail to be able to compare actual and forecast costs at the town and function level. This would provide a more robust basis on which to draw cost comparisons between different functions in the supply chain and between different regional systems. This in turn would inform the setting of escalation factors and efficiency targets. A second inquiry would also provide an opportunity for the Authority to consider adjusting for any assumptions made in the previous inquiry that proved to be inaccurate, e.g. escalation and demand forecasts).

13.4 Final recommendation

13) A second inquiry into the funding arrangements of Horizon Power be undertaken in three years time to further review Horizon Power's actual costs and to set new efficiency targets.

[193] Alinta (2011), Inquiry into the funding arrangements of Horizon Power, p4

APPENDICES

Appendix A: Terms of Reference

INQUIRY INTO THE FUNDING ARRANGEMENTS OF HORIZON POWER

FINAL TERMS OF REFERENCE

I, COLIN BARNETT, Treasurer, pursuant to Section 32(1) of the *Economic Regulation Authority Act 2003*, and in accordance with section 129E(1) of the *Electricity Industry Act 2004*, request that the Economic Regulation Authority (the Authority) undertake an inquiry into the funding arrangements, and operating and capital expenditure programmes of the Regional Power Corporation (Horizon Power).

In doing so, the Authority is expected to consider and develop findings on:

- The cost-reflective retail tariffs that would apply in the areas of operation of Horizon Power, for the purpose of determining the efficient expenditure required to supply customers on regulated retail tariffs located in these areas. This will inform the setting of the amount of the Tariff Equalisation Contribution (TEC), which will be determined by Government.

- The cost-reflective retail tariffs should be determined for the period 2009/10 to 2013/14.

- A cost-reflective retail tariff should be determined for each of the retail tariffs currently provided by Horizon Power, being the A2, K2, L2, M2, N2, W2 and Streetlight tariffs (as detailed in the Energy Operators (Regional Power Corporation) (Charges) By-laws 2006).

- The Authority is to determine whether the area that Horizon Power operates in should be separated into sub-areas, given the different cost structures of the systems that Horizon Power operates, for the purpose of determining cost-reflective retail tariffs. If this is the case, the Authority is to:

    - define the sub-areas (minimising the number of sub-areas as much as possible); and

    - determine a different cost-reflective retail tariff (for each tariff class) for each sub-area.

- The Authority is also to take into account the following costs when determining the retail tariffs, but is not limited to considering only these costs:

    - the efficient generation costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current and committed stock of generation;

    - the efficient network costs applicable in the area Horizon Power operates in or each sub-area, if applicable, taking into account the current network infrastructure;

    - the efficient level of retail costs that would be applicable in the area that Horizon Power services (both operating and capital costs);

    - the efficient net retail margin that would apply;

- the efficient costs related to the national Mandatory Renewable Energy Target (MRET), including the expanded MRET if applicable; and

- the efficient costs related to the proposed Carbon Pollution Reduction Scheme (CPRS), including the carbon intensity that should be applied in determining CPRS costs that would be incorporated into the cost-reflective retail tariffs.

- The Authority is also to consider and incorporate incentives for Horizon Power to develop and implement efficiency measures, such as gain-sharing mechanisms between customers and Horizon Power, in determining cost-reflective retail tariffs if the Authority considers this would minimise costs within the area that Horizon Power operates in.

- The efficiency of Horizon Power's procurement processes.

- The efficiency of Horizon Power's operating and capital expenditure programmes, including opportunities of alternative arrangements for service delivery in remote regions.

The Authority should note the following:

- The TEC refers to the amount payable by the Electricity Networks Corporation (Western Power) to the Tariff Equalisation Account to contribute towards maintaining the financial viability of Horizon Power, as set out in part 9A of the *Electricity Industry Act 2004*.

- The Department of Treasury and Finance and the Office of Energy are currently in the process of developing a revised framework for determining the TEC amount, including a post adjustment mechanism to vary the TEC set for 2009/10 to 2011/12.

The Authority will release an issues paper as soon as possible after receiving the reference. The paper is to facilitate public consultation in the basis of invitations for written submissions from industry, government and all other stakeholder groups, including the general community.

A draft report is also to be made available for public consultation.

The Authority will complete a final report on the findings of the inquiry no later than 18 March 2010.

COLIN BARNETT MLA
PERMIER; TREASURER

Appendix B: ICB values by location at 1 April 2006 and 30 June 2009

Location	2006 ICB value ($'000s)	2009 ICB value ($'000s)
Ardyaloon	-	-4,897
Beagle Bay	-	1,469,766
Bidyadanga	-	-4,605
Broome	16,545,210	41,164860
Camballin/Looma	277,194	634,281
Carnarvon	14,374,867	16,893,023
Coral Bay	-	1,036,775
Cue	830,453	1,890,938
Denham	1,905,157	2,368,319
Derby	2,771,741	5,364,138
Djandinjin	-	-82,533
Esperance	26,996,071	38,482,653
Exmouth	3,384,478	5,020,064
Fitzroy Crossing	1,966,276	4,433,600
Gascoyne Junction	-	-8,081
Halls Creek	1,240,608	2,517,147
Hopetoun	904,003	5,331,423
Kalumburu	-	-
Kununurra	20,598,994	27,703,510
Lake Argyle	185,423	149,074
Laverton	654,044	1,614,721
Leonora	1,637,540	1,638,793
Marble Bar	430,820	628,830
Meekatharra	6,833,745	2,472,767
Menzies	199,085	578,001
Mount Magnet	1,144,071	1,643,088
Norseman	1,023,963	950,322
Nullagine	266,445	243,547
Onslow	3,615,291	3,185,645
Sandstone	484,717	511,391
Warmun	-	335,138
Wiluna	798,054	925,686
Wyndham	1,122,978	1,288,313
Yalgoo	322,251	471,931
Yungngora	-	-

Location	2006 ICB value ($'000s)	2009 ICB value ($'000s)
NWIS	192,367,358	207,991,987
Bentley	1,972,791	7,602,777
East Kimberley	-	2,096
Esperance(Goldfields)	-	30,298
Gascoyne Midwest	-	9,558
Pilbara	677,303	544,094
West Kimberley	1,786,008	1,625,933
Aggregate	307,346,940	388,654,370

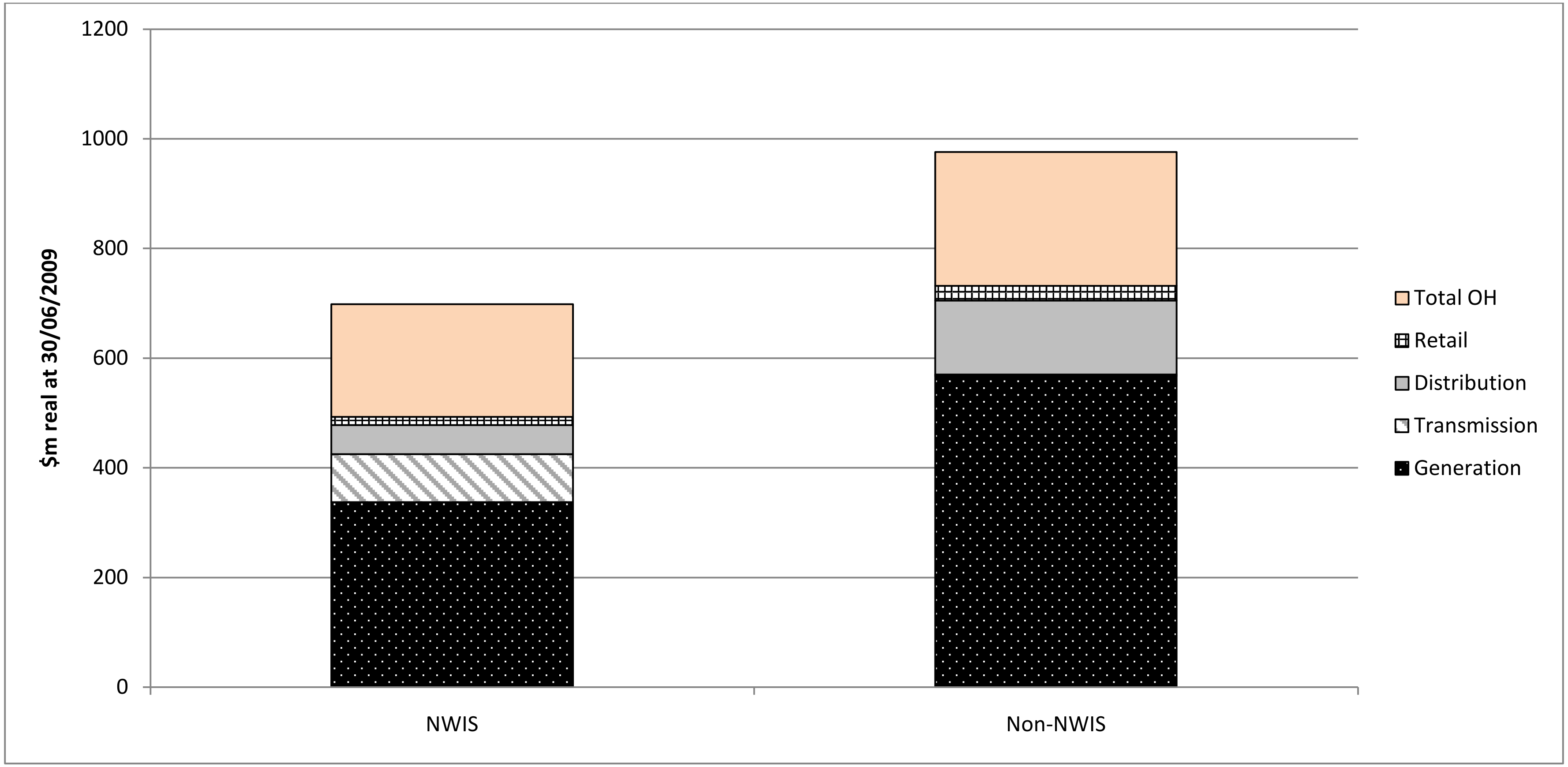
Appendix C: DWATs by town

Location	ERA DWATS
Ardyaloon	1.0634
Beagle Bay	1.2075
Bidyadanga	0.8077
Broome	0.3399
Camballin/Looma	0.6132
Carnarvon	0.4631
Coral Bay	1.0081
Cue	0.8015
Denham	0.6280
Derby	0.3526
Djandinjin	0.10678
Esperance	0.5624
Exmouth	0.5404
Fitzroy Crossing	0.3892
Gascoyne Junction	1.3013
Halls Creek	0.5124
Hopetoun	1.0397
Kalumburu	1.0002
Kununurra	0.3301
Lake Argyle	0.2829
Laverton	0.7484
Leonora	0.4374
Marble Bar	1.2388
Meekatharra	0.6912
Menzies	1.4701
Mount Magnet	0.5124
Norseman	0.5392
Nullagine	1.4556
Onslow	0.4671
Sandstone	1.2255
Warmun	0.8859
Wiluna	1.0006
Wyndham	0.2696
Yalgoo	1.1242

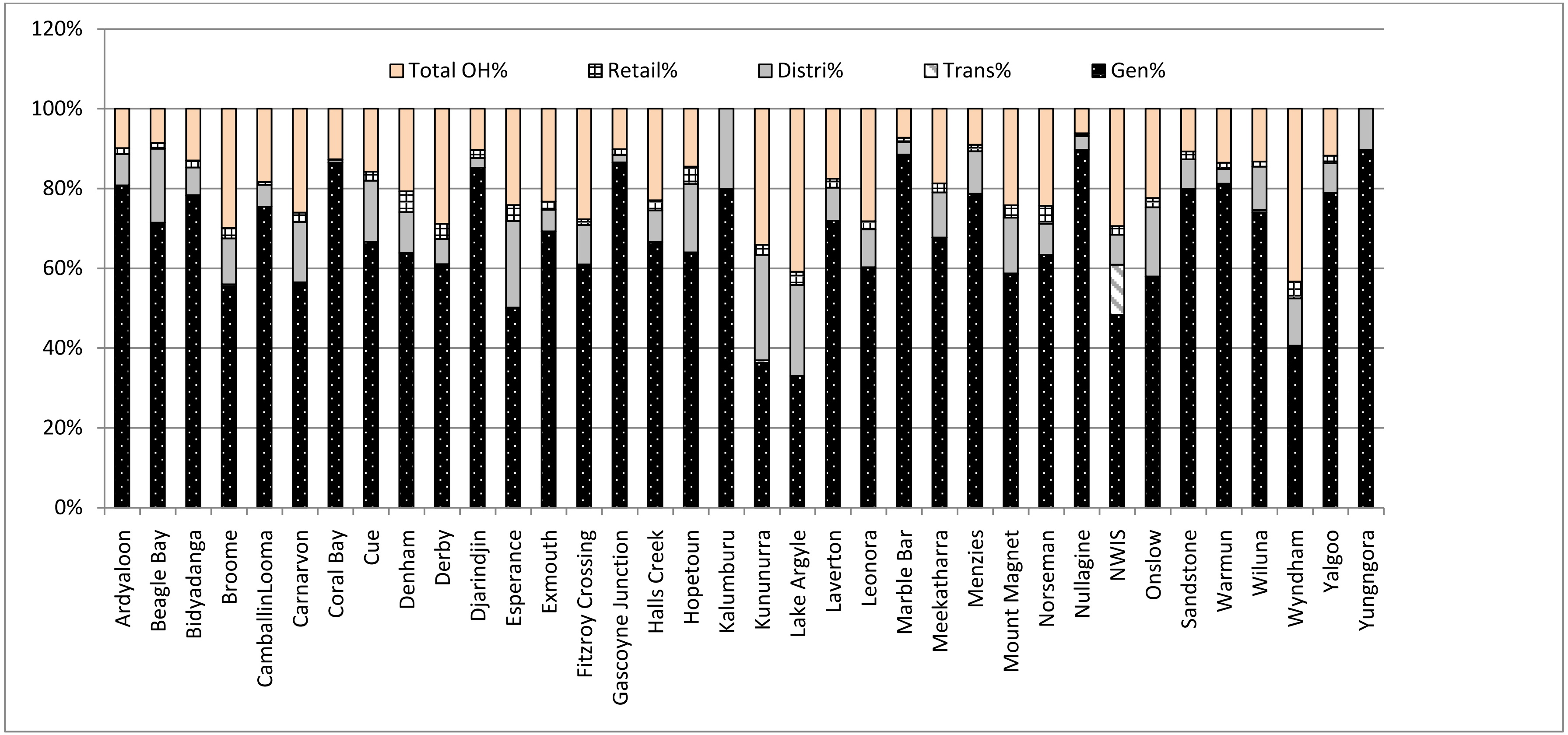
Location	ERA DWATS
Yungngora	n/a
NWIS	0.3159
Aggregate	0.3843

Source: ERA analysis

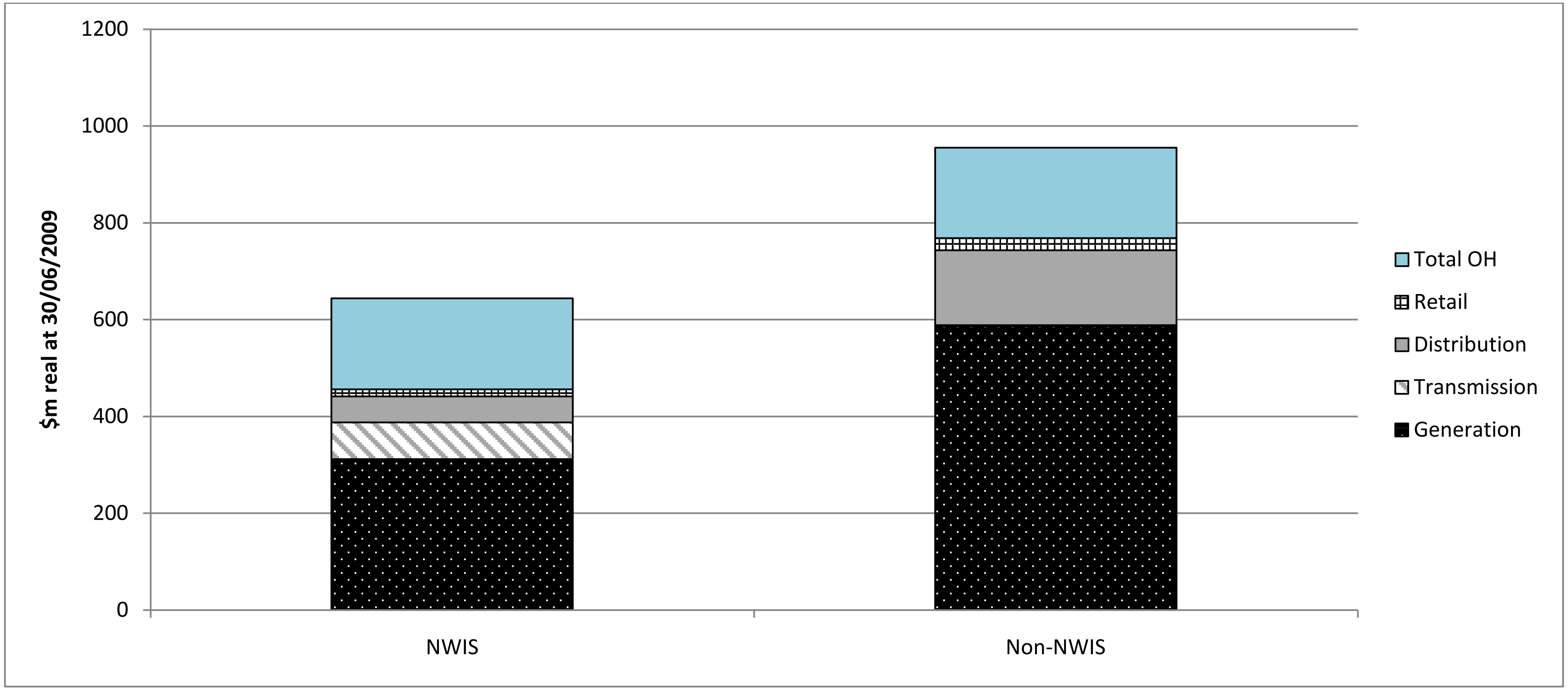
Appendix D: Cost of service by function for NWIS and non-NWIS (Horizon Power's forecasts)



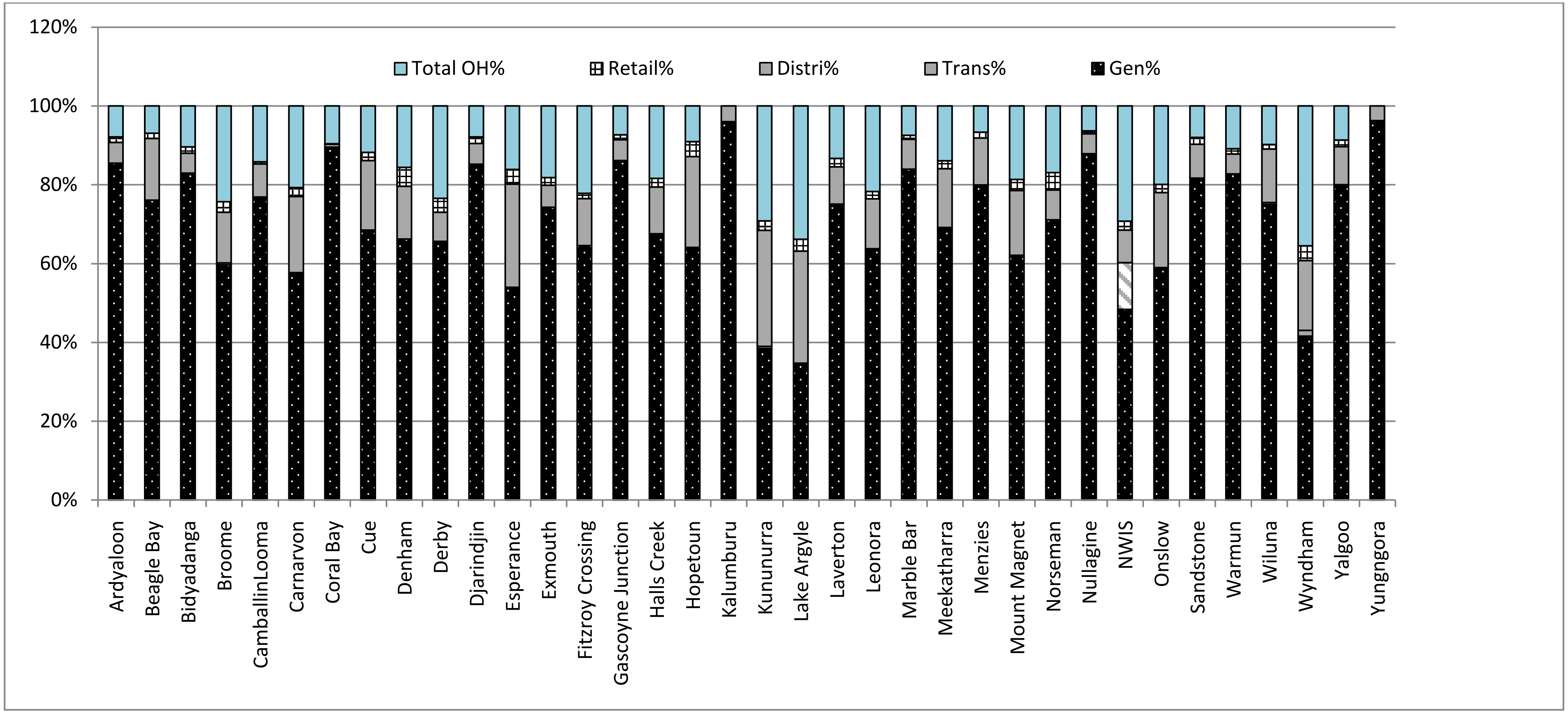
Appendix E: The percentage contribution of each function to total cost of service for each town (%) (Horizon Power's forecasts)



Appendix F: Cost of Service by function for NWIS and non-NWIS (ERA forecasts)



Appendix G: The percentage of each function to the total cost of service for each town (ERA forecasts)



Appendix H: Technical information on WACC

Method for calculation of Rate of Return

The nominal post-tax WACC formula:

In the absence of an imputation tax system, the nominal post-tax form of the Weighted Average Cost of Capital (WACC) is expressed as below:

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

where:

- $E(R_e)$ is the nominal post-tax expected rate of return on equity - the cost of equity;
- $E(R_d)$ is the nominal pre-tax expected rate of return on debt - the cost of debt;
- E/V is the proportion of equity in the total financing (which comprises equity and debt);
- D/V is the proportion of debt in the total financing; and
- T_c is the tax rate.

The Australian tax system provides credits to shareholders for tax already paid at the corporate level, to avoid double taxation of the same income stream. In this circumstance, the nominal post-tax WACC formula needs to be modified to reflect the additional element of shareholders' return available through the taxation system. This is an estimate of the post-tax return on assets in the presence of an imputation credit tax system:

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

where γ (gamma) is the value of franking credits created (as a proportion of their face value).

The nominal pre-tax WACC formula:

This is an estimate of the pre-tax return on assets, which can be obtained by dividing the right hand side of the formula for the above nominal post-tax return on assets by the component $(1 - T_c)$, which can be expressed as:

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

The real pre-tax WACC formula:

A real pre-tax WACC is obtained by removing expected inflation π_e from the nominal pre-tax WACC:

$$WACC_{\text{real pre-tax}} = \frac{\left(1 + WACC_{\text{nominal pre-tax}}\right)}{1 + \pi_e} - 1$$

Authority's comments

While all regulators of utility industries in Australia use the CAPM to estimate the cost of capital, there is no clear precedent on the form of the WACC to be used (i.e. pre-tax or post-tax, real or nominal).

- A pre-tax real WACC has been generally preferred by the Independent Pricing and Regulatory Tribunal of New South Wales (**IPART**) and the Independent Competition and Regulatory Commission (**ICRC**) of the Australian Capital Territory.
- The Australian Competition and Consumer Commission (**ACCC**) and the Australian Energy Regulator (**AER**) have used a post-tax nominal form of the WACC in recent decisions.
- The Essential Services Commission of Victoria (**ESC**) has used a post-tax real form of the WACC in recent decisions.

The Authority notes that Deloitte's proposed method of ascertaining a rate of return using a real pre-tax WACC is appropriate and this proposal is also consistent with the Authority's preference. The Authority is therefore satisfied that the proposed method of calculating the rate of return using a real pre-tax WACC formula meets the requirements of the NGL and NGR.

The Authority also prefers a real pre-tax WACC approach, as this method:

- simplifies financial modelling;
- is consistent with the preferences of major utilities in Western Australia (e.g. Water Corporation and Western Power); and
- allows consistency across regulated utilities in Western Australia.

Methods for estimating the Cost of Equity

Horizon Power's proposal

Horizon Power proposes to use the Capital Asset Pricing Model, on the advice of Deloitte, to estimate the cost of equity. However, an extra element, known as specific company risk premium, is added.

$$K_e = R_f + \beta \times \left(R_m - R_f\right) + \alpha$$

where:

- K_e is required return on equity
- R_f is the risk free rate of return
- R_m is the expected return on the market portfolio
- β is beta, the systematic risk of a stock; and
- α is specific company risk premium

Authority's comments

The Authority agrees with Horizon Power's proposal to use the standard CAPM (known as Sharpe-Litner CAPM) to estimate the cost of equity.

The central implication of CAPM is that the contribution of an asset to the systematic risk (also known as beta risk) is the correct measure of the asset's risk and the only systematic determinant of the asset's return. There are two main components of CAPM: the market portfolio M, and beta risk β of a portfolio, which correlates the portfolio to the rise and fall of the market.

Under the CAPM model, the total risk of an asset can be divided into systematic and non-systematic risk. Systematic risk is a function of broad macroeconomic factors (such as interest rates) that affect all assets and cannot be eliminated by diversification of the businesses asset portfolio. In contrast, non-systematic risk relates to the attributes of a particular asset, with this risk managed by portfolio diversification.

In estimating the cost of equity, Horizon Power proposes to take into account both systematic and non-systematic risks which are in contrary with the standard CAPM and regulatory practices: only systematic risk is compensated for regulated businesses. As such, the Authority is of the view that the cost of equity is estimated by using the standard CAPM.

$$K_e = R_f + \beta \times \left(R_m - R_f\right)$$

Nominal risk free Rate of Return

Horizon Power's proposal

Horizon Power has approximated the risk free rate of return using the proxy of daily yield data for Commonwealth Government securities with terms to maturity of 10 years, reported by the Reserve Bank of Australia.

Horizon Power proposes a nominal risk free rate of return of 5.43 per cent.[194] This is the average of 10-year Commonwealth Government Securities for the 20 trading days to 8 September 2009 as reported by the Reserve Bank of Australia.

[194] Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p4

Authority's comments

The risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments (i.e. no risk of default). The Commonwealth government bond is widely used as a proxy for the risk free rate in Australia.[195] CAPM theory does not provide guidance on the appropriate proxy for the risk free rate. In Australia, regulators' current practice is to average the yield on the indexed 10-year Commonwealth government bond for a period of 20 trading days as close as feasible before the day the decision is made.

Recent decisions by economic regulators in Australia generally use the implied yields on 10-year nominal government bonds as a proxy for the risk free rate. The Authority prefers to use a 20-day moving average[196] of observed rates of return on 10-year Commonwealth government bonds as an estimate of the risk free rate.

The Authority agrees that Horizon Power's proposed approach to determining the nominal risk free rate of return is appropriate. It is a method which has been adopted by most Australian economic regulators (e.g. the AER, ESC and IPART). The data adopted by Horizon Power for the calculation of the nominal risk free rate was current as at 8 September 2009 which is quite outdated now.

For the purpose of this draft report, the Authority adopts the updated values, as at 28 February 2011. Adopting these updated values and the calculation approach proposed by Horizon Power, the Authority calculates a nominal risk free rate of 5.71 per cent.

Based on an estimated nominal risk free rate of return of 5.71 per cent and an assumed inflation rate of 2.57 per cent, the Authority estimates a real risk free rate of 3.06 per cent.

Market Risk Premium

Horizon Power's proposal

On the advice from Deloitte, Horizon Power submits that the market risk premium (MRP) of 6 per cent to 7 per cent[197] has been arrived at on a reasonable basis, and represents the best estimate possible in the circumstances.

Authority's comments

The market risk premium is the required return, over and above the risk free rate, on a fully diversified portfolio of assets.

It is the current practice of regulators across Australia to estimate the MRP using the historical data on equity premia.

[195] Although Blanco *et al* consider swap rates as superior to Government bonds as a proxy for the risk free rate and state that "it is well known that government bonds are no longer an ideal proxy for the unobservable risk free rate". See Blanco, Brennan, and Marsh, "An Empirical Analysis of the Dynamic Relation between Investment-Grade Bonds and Credit Default Swaps", *The Journal Of Finance*, Vol. LX, no. 5 October 2005, p2261, for details

[196] There are three different types of moving averages: (i) Simple Moving Average; (ii) Exponential Moving Average; and (iii) Weighted Moving Average, and they are all calculated slightly differently. However, all have a similar smoothing effect on the data, so that any unexpected changes on rates are removed, and, as a result, the overall direction is shown more clearly. For simplicity, the Authority adopts the simple moving average in its calculations.

[197] Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p5

Australian regulators have consistently applied a MRP of 6 per cent in their decisions, except for the AER's decisions after its review of WACC parameters released in May 2009. It is noted that a MRP of 6 per cent was first adopted in Australia by the ACCC[198] and the Victorian Office of the Regulator General. A MRP range of 4.5-7.5 per cent was derived on the basis of consultant work prepared by Professor Davies at the University of Melbourne, where the upper bound of this range was based on historical estimates and the lower bound was based on cash flow measures.[199] As such, the mid-point of that range (6 per cent) was adopted. Subsequently, Australian regulators have consistently applied a MRP of 6.0 per cent, which is estimated using historical data on equity premia.

In its review of WACC parameters for electricity distribution and transmission networks in May 2009, the AER commissioned Associate Professor Handley at the University of Melbourne to update historical excess returns using full year data for 2008. The estimates for this study covered the periods of 1883-2008, 1937-2008, 1958-2008, 1980-2008 and 1988-2008, were relative to 10-year Commonwealth Government Securities, were grossed-up for a theta[200] of 0, 0.28, 0.5, 0.65 and 1.0 and included standard errors and 95 per cent confidence intervals. The results are presented in below.

Table H 1 Historical excess returns (Arithmetic average, relative to 10-year bonds, 'grossed-up' for value of imputation credits distributed, per cent)

Utilisation rate	0.00	0.28	0.5	0.65	1.00
1883-2008	5.9*	6.0*	6.1*	6.1*	6.2*
1937-2008	5.4*	5.5*	5.6*	5.7*	5.9*
1958-2008	5.7	5.9	6.1	6.2*	6.4*
1980-2008	5.0	5.3	5.6	5.8	6.3
1988-2008	3.8	4.3	4.7	5.0	5.6

*Indicates estimates are statistically significant at the five per cent level based on a two-tailed t-test.

Source: Handley (2009).[201]

The above estimates reveal that the most recent long-term historical average excess returns estimated over a range of long-term estimation periods (1883-2008, 1937-2008, 1958-2008), once 'grossed-up' for a utilisation rate of 0.65 and estimated relative to the yield on 10-year Commonwealth Government Securities, is close to 6 per cent (between 5.7 and 6.2 per cent).

An estimate of MRP of 6 per cent, from the AER's view, was the best estimate of a forward-looking long-term value for MRP prior to the onset of the global financial crisis under relatively stable market conditions with the assumption that there is no structural break which has occurred in the market. However, given the state of the international financial market at that time (May 2009), when relatively stable market conditions did not

198 ACCC, Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System – Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System – Access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System, Final Decision, 6 October 1998

199 ORG, Access arrangements – Multinet Energy Pty Ltd and Multinet (Assets) Pty Ltd – Westar (Gas) Pty Ltd and Westar (Assets) Pty Ltd – Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd , Final decision, October 1998

200 Theta is the value of a franking credit to investors at the time they receive it.

201 J. C. Handley, *Further comments on the historical market risk premium*, Report prepared for the AER, 14 April 2009, pp6-9

exist, and taking into account the uncertainty surrounding the global economic crisis, the AER considered that a MRP of 6.5 per cent was reasonable.

> "The AER considers that prior to the onset of the global financial crisis, an estimate of 6 per cent was the best estimate of a forward looking long term MRP, and accordingly, under relatively stable market conditions - assuming no structural break has occurred in the market - this would remain the AER's view as to the best estimate of the forward looking long term MRP." [emphasis added] [202]

The current state of the Australian financial market has significantly improved, as evidenced by six consecutive increases in the cash rate by the Reserve Bank of Australia since 7 October 2009. In its recent Statement on Monetary Policy Decision in August 2010, the Reserve Bank stated that:

> "The Australian economy continued to expand at a solid pace over the first half of 2010. The economy is benefiting from elevated commodity prices and high levels of public investment. Employment growth has been strong and confidence remains generally positive. Over the period ahead, some rebalancing of growth is expected, with public investment likely to decline as stimulus projects are completed, while private demand is expected to strengthen. The outlook for investment in the resources sector remains especially positive and the high level of the terms of trade is boosting incomes and demand." [203]

[and]

> "Since the *Statement* in May, the Reserve Bank Board has maintained its target for the overnight cash rate at 4.50 per cent. An intensification in pressures in global financial markets over recent months saw domestic yields move to price in some probability that the cash rate target could be reduced later in 2010. More recently, as global conditions have stabilised and domestic indicators have pointed to a reasonably buoyant domestic outlook, money market yields have shifted to imply a small chance that monetary policy may be tightened in the year ahead." [204]

[and]

> "The strong growth in Asia over the past year has led to large rises in the contract prices of iron ore and coal, which are Australia's two largest exports. As a result, Australia's terms of trade are back around the historically very high levels that they reached in 2008. While the spot prices for many commodities have fallen over the past few months – reflecting the concerns in Europe and signs of growth moderating in China – Australia's terms of trade seem likely to remain very high over the next couple of years." [205]

The Authority also observes that 6.0 per cent is the market risk premium value most commonly used by market practitioners. Surveys of market risk practice show that 47 per cent of market practitioners apply a MRP of 6.0 per cent, while 69 per cent apply a value of 6.0 per cent or less. Only 26 per cent of market practitioners apply values of MRP more than 6.0 per cent.[206] However, the Authority is aware that this information preceded the global financial crisis in 2008.

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[202] Australian Energy Regulator, May 2009, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p175

[203] The Reserve Bank of Australia, (August 2010), Monetary Policy Decision, accessed at http://www.rba.gov.au/publications/smp/index.html, p29

[204] The Reserve Bank of Australia, (August 2010), Monetary Policy Decision, accessed at http://www.rba.gov.au/publications/smp/index.html, p39

[205] The Reserve Bank of Australia, (August 2010), Monetary Policy Decision, accessed at http://www.rba.gov.au/publications/smp/index.html, p1

[206] G. Truong, G. Partington and M. Peat, 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008, p155

IPART has used a market risk premium range of 5.5 per cent to 6.5 per cent in its recent determinations, such as for metropolitan and outer metropolitan bus services in December 2009, the CityRail determination, and recent determinations on prices charged by Sydney Catchment Authority and Hunter Water. IPART argues that MRP derived from a long-term historical time series remains appropriate. IPART also considers that relying on a long-term historical time series adequately takes into account any impact on excess returns of recent market events such as the global financial crisis.

The Queensland Competition Authority has also used 6.0 per cent for MRP in the Draft determination for Queensland Rail in December 2009. QCA argued that it did not lower the MRP when the market conditions at the time led some stakeholders to seek a reduction – therefore increasing the MRP now would be inconsistent with its past practice that sets the MRP at a level to encourage investment over the medium term and not in response to short-term market fluctuations. The Authority is aware that the AER has adopted a MRP of 6 per cent in its most recent draft decision on Envestra's access arrangement proposal for the South Australian gas network, released in February 2011, on the following grounds.[207]

First, the estimates of historical excess returns for three periods up to 2010 provided by Associate Professor John Handley. These estimates are arithmetic means and with data available to the end of 2010 provide a range of 6.1 per cent to 6.6 per cent.

Table H 2 Estimates of the Market Risk Premium (assumed value of gamma of 0.65), using arithmetic means

Period	MRP (per cent)	95 per cent confidence interval (per cent)
1883-2010	6.3	3.4 – 9.2
1937-2010	6.1	1.5 – 10.7
1958-2010	6.6	0.4 – 12.9

Source: Handley, *An estimate of the historical equity risk premium for the period for 1883 – 2010*, January 2011, page 8. A report for the AER

The AER notes that the above estimates of the historical equity risk premium are accompanied by very wide confidence intervals. As a result, there is low statistical precision in these estimates. The AER also notes that these estimates are not inconsistent with the estimates prior to the Global Financial Crisis.

Second, the AER considers that these estimates would be taken into account by investors. However, the investors' expectation of the long run forward looking MRP is unlikely to change annually in response to the latest historical estimates of the type calculated by Handley.

Third, the above estimates of the MRP in Table H 2 use the arithmetic means. AER notes that using geometric means is more appropriate when annual returns are related to each other over time. As long as returns vary over time, a geometric mean will be less than an arithmetic mean. The greater the volatility in returns, the greater the difference between

[207] Australian Energy Regulator, February 2011, Draft Decision, Envestra Ltd. – Access Arrangement proposal for the SA gas network, pp 83-92

arithmetic means and geometric means. Using geometric means, the estimates of historical excess returns for three periods up to 2010 provided by Associate Professor John Handley are summarised in Table H 3 below.

Table H 3 Estimates of the Market Risk Premium (assumed value of gamma of 0.65), using geometric means

Period	MRP (per cent) Using Geometric means	MRP (per cent) Using Arithmetic means
1883-2010	4.9	6.3
1937-2010	4.1	6.1
1958-2010	4.1	6.6

Source: Handley, *An estimate of the historical equity risk premium for the period for 1883 – 2010*, January 2011, page 8. A report for the AER

Rather than using a complex weighted average approach, the AER is of the view that the estimates of the MRP using arithmetic means should be interpreted with the understanding that these estimates may overestimate the expected forward-looking MRP.

Fourth, in conclusion, the AER considers that the available evidence on the MRP is imprecise and is subject to a wide margin of variation. As a result, the AER is of the view that the MRP of 6 per cent is the best estimate of the forward-looking MRP.

The Authority adopts the same approach it took in its Final Decisions on the Proposed Revisions to the Access Arrangement for the South West Interconnected Network in December 2009; and on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline in May 2010, for the same reasons as applied in those decisions. This approach is consistent with historical regulatory practice. In these two final decisions, the Authority has adopted the range of 5 per cent to 7 per cent with the view that the point estimate of 6 per cent as the reasonable estimate for the MRP is to be adopted.

In addition, the Authority also adopted a MRP of 6.0 per cent in its most recent Final Decision on Western Australian Gas Networks in February 2011 and its Draft Decision on Dampier Bunbury National Gas Pipeline in March 2011.

The Authority is of the view that a MRP of 6 per cent will be within the reasonable range of values. This is consistent with the view with some other Australian regulators, including IPART and QCA. The estimate of the MRP of 6 per cent also reflects the view by the AER that this is the best estimate of a forward-looking long-term MRP.

In conclusion, the Authority considers that a reasonable point estimate for the MRP is 6 per cent.

Cost of Debt

Horizon Power's proposal

On the advice of Deloitte, Horizon Power submits that Horizon Power has historically received funds at 70 to 80 basis points above the risk free rate and that the cost of debt for Horizon Power should reflect the split between the source of its debt funding, such that it reflects a mix of government subsidised and commercially available debt.[208]

Deloitte submits the following estimates of credit spreads of A rated and BBB rated corporate bonds from both Australian financial market and the US market: [209]

- current credit spreads for A rated Australian and US corporate bonds are in the range of 160 to 205 basis points and 140 to 200 basis points respectively over the equivalent risk free rate;
- current credit spreads for BBB rated Australian and US corporate bonds are in the range of 250 to 350 basis points and 280 to 305 basis points respectively over the equivalent risk free rate;
- current credit spreads for A rated US corporate bonds of utilities are in the range of 110 to 140 basis points over the equivalent risk free rate; and
- current credit spreads for BBB rated US corporate bonds of utilities are in the range of 195 to 255 basis points over the equivalent risk free rate.

Based on the above information, Deloitte argues that debt margin of 180 to 200 basis points on the basis that Horizon Power will continue to secure subsidised debt funding.[210]

Authority's comments

The debt margin (also referred to as the debt premium) is a margin above the risk free rate reflecting the risk in provision of debt finance to the regulated activity.

Debt Risk Premium

Methodology

In its previous decisions, the Authority relied on the estimates of 10-year fair yield curves derived by Bloomberg and CBASpectrum. However, Bloomberg has in recent times progressively shortened its estimates of fair yields across credit ratings for Australian corporate bonds. Additionally, in September 2010, CBASpectrum ceased publishing its estimates of the fair yield curves across all credit ratings for Australian corporate bonds.

It is noted that the Authority's method for estimating the debt risk premium, as well as the nominal risk free rate, has in the past assumed the borrowing term is 10 years. A 10-year term has been consistently adopted by all Australian regulators in the energy sector since the Australian Competition Tribunal's (**Tribunal**) 2003 GasNet decision.[211]

208 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p10

209 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p11

210 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p10

211 Australian Competition Tribunal, *Application by GasNet Australia (Operations) Pty Ltd [2003] ACompT 6*, 23 December 2003, paragraph 48, p18

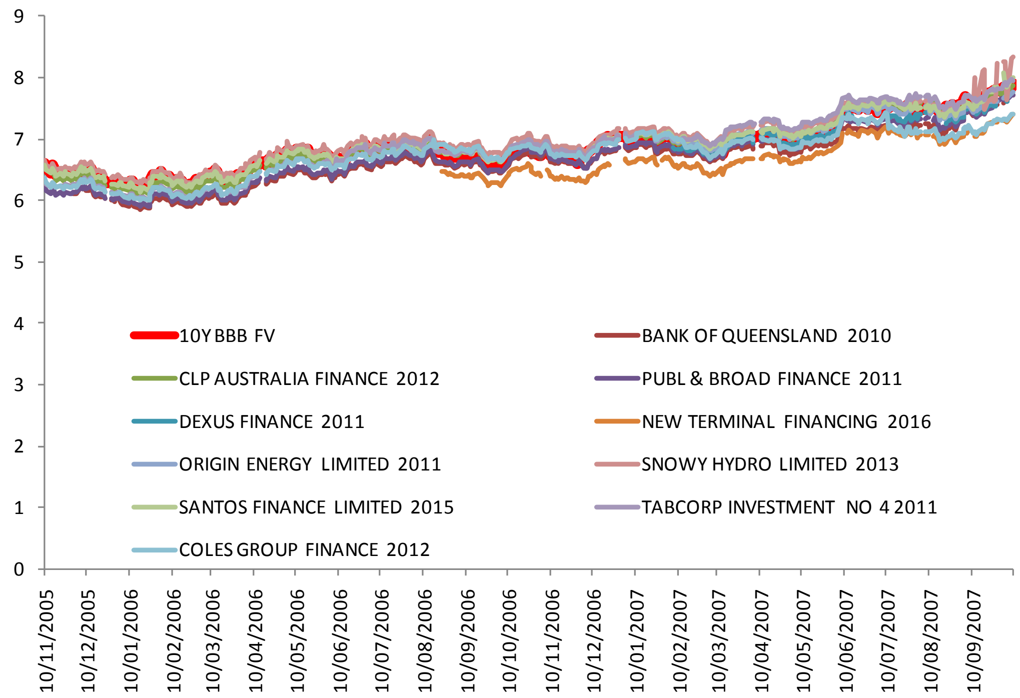
There have also been recent developments in the Australian regulatory environment regarding the approach to estimating the debt risk premium.

- The Australian Competition Tribunal's decision in the ActewAGL appeal in September 2010.
- The Australian Energy Regulator's (AER) Final Decision on the Victorian electricity Distribution Network Service Providers (DNSPs) in October 2010.
- The Independent Pricing and Regulatory Tribunal of New South Wales' (IPART) Discussion Paper on "Developing the approach to estimating the debt margin" in November 2010.

The Estimates of Bloomberg's Fair Yield Curves

Australian regulators have historically had regard to Bloomberg's estimates of fair yield curves to estimate the debt risk premium for their regulatory decisions. Prior to the Global Financial Crisis, which started in 2008, an estimate of the fair yield curve for 10-year BBB Australian corporate bonds was consistent with observed yields for Australian corporate bonds (of the same rating) trading in the market at that time. This consistency is illustrated in Figure H 1 below using estimates of the fair yield curve for 10-year BBB Australian corporate bonds from 10 November 2005 to 9 October 2007.

Figure H 1 Bloomberg's 10-year BBB fair yield curve and observed yields for BBB/BBB+ Australian corporate bonds, 10 November 2005 – 9 October 2007 (per cent)



Source: Bloomberg

Since the cessation of Bloomberg's estimate of the 10-year BBB fair yield curve on 9 October 2007, some Australian regulators, including the Authority and the AER, have extrapolated to a 10-year term from Bloomberg's estimate of the 8-year BBB fair yield curve. The extrapolation was based on the assumption that the yield spreads between 10Y A and 8Y A is equal to that of 10Y BBB and 8Y BBB:

$$10\text{Y BBB} = 8\text{Y BBB} + \left(10\text{Y A} - 8\text{Y A}\right)$$

The above extrapolation was not possible after 18 August 2009 when Bloomberg ceased providing estimates of 8-year BBB fair yield curve, and 10-year and 8-year A fair yield curves.

The Authority, as well as the AER, then analysed the appropriateness of using other fair yield curves from Bloomberg to extrapolate to a 10-year BBB fair yield curve. Both regulators came to the conclusion that the difference between the 10-year and 7-year AAA fair yields should be added to the 7-year BBB fair yield to gain an estimate of the 10-year BBB fair yield.

$$10\text{Y BBB} = 7\text{Y BBB} + \left(10\text{Y AAA} - 7\text{Y AAA}\right)$$

However, on 22 June 2010 Bloomberg again shortened its estimates of fair yield curves for Australian corporate bonds by ceasing to publish its estimates for both 10-year and 7-year AAA fair yield curves.

The duration of Bloomberg's fair yield curves are now well below the 10-year time period which Australian regulators have traditionally used for setting the debt risk premium and risk free rate.

It is understood that Bloomberg is currently deriving estimates of the fair yield curves for the credit ratings and terms to maturity shown in Table H 4 below. Bloomberg estimates the fair yield curves for 5-year terms across all credit ratings. For the credit ratings of A and BBB, Bloomberg also estimates the fair yield curves for 7-year terms to maturity, although there are no estimates for 6-year fair yield curves.

Table H 4 List of fair yield curves from Bloomberg as at 18 November 2010

	Credit rating	Maturity (M=Month; Y=Year)
1	AUD Australia AAA[212]	3M, 6M, 1Y, 2Y, 3Y, 4Y, and 5Y
2	AUD Australia AA[213]	3M, 6M, 1Y, 2Y, 3Y, 4Y, and 5Y
3	AUD Australia A[214]	3M, 6M, 1Y, 2Y, 3Y, 4Y, 5Y, and 7Y
4	AUD Australia BBB[215]	3M, 6M, 1Y, 2Y, 3Y, 4Y, 5Y, and 7Y

Source: Bloomberg

A major concern is that, since the bond market is thinner[216] than in the past, Bloomberg's estimate of the 7-year BBB fair yield curve is substantially different from the observed bond yields in the Australian bond market, as illustrated in Figure H 2 below. This illustration is for the period when data on yield for the 7-year BBB is most recently available - after the cessation of the Bloomberg's estimate of 8-year BBB on 18 August 2009 until the end of October 2010. Since the method used by Bloomberg to derive its fair yield curves is not released to the public, the Authority is unable to understand and verify this difference.

[212] Bloomberg ceased publishing its estimates of the fair yield curves for AAA 7Y, 8Y, 9Y, 10Y, and 15Y on 22 June 2010; and for AAA 20Y on the 30 June 2005

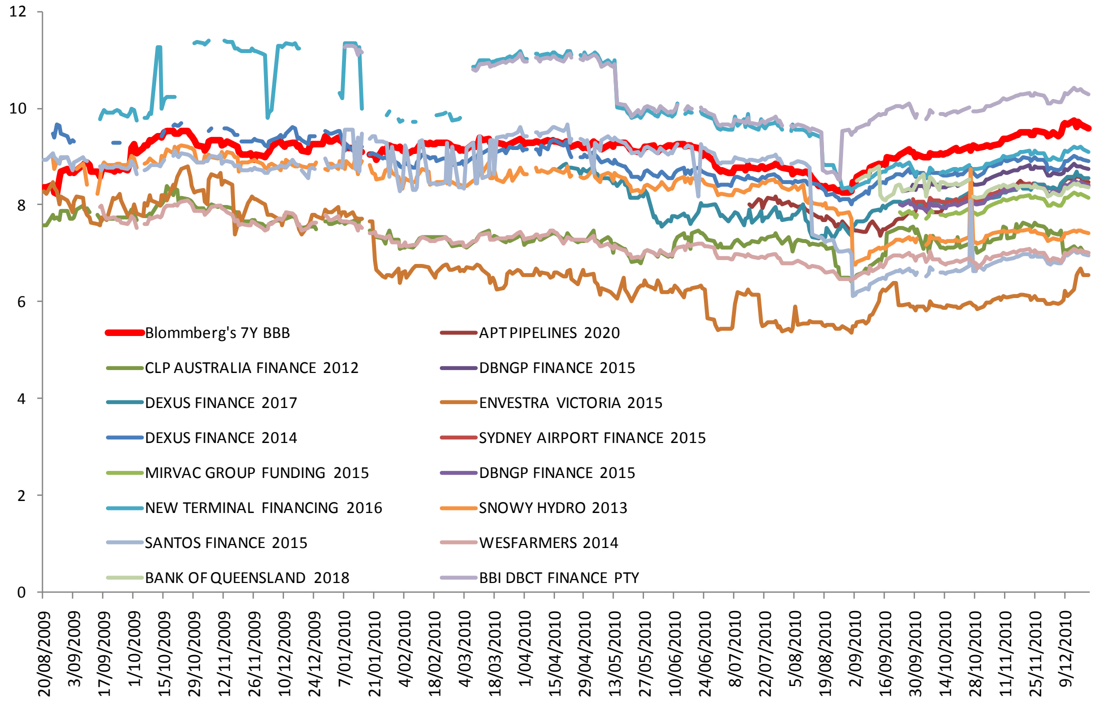
[213] Bloomberg ceased publishing its estimates of the fair yield curves for AA 7Y on 18 August 2009; and for AA 8Y on 19 June 2006

[214] Bloomberg ceased publishing its estimates of the fair yield curves for A 8Y, 9Y, and 10Y on 18 August 2009

[215] Bloomberg ceased publishing its estimates of the fair yield curves for BBB 8Y on 18 August 2009; for BBB 9Y, and 10Y on 9 October 2007; and for BBB 15Y on 14 March 2002

[216] This means that the volumes traded in the market are lower than desirable for the derivation of average values.

Figure H 2 Bloomberg's 7-year BBB fair yield curve and observed yields for BBB/BBB+ Australian corporate bonds, 19 August 2009 – 31 October 2010 (per cent)



Source: Bloomberg

The Australian Competition Tribunal's decision on the ActewAGL matter in 2010

Regulators have historically used a 10-year term for estimation of the debt risk premium. However, the Authority notes that the Australian Competition Tribunal, in its recent decision for the ActewAGL gas network in September 2010, commented that:

> "The reason a 10 year bond was originally chosen was because, in the past, many firms favoured long term debt, albeit that it came at a higher cost, because it reduced refinancing or roll-over risks. The high rate was then hedged via interest rate swaps. That may no longer be the position. If not, the AER may need to reconsider its approach in light of more current strategies of firms in the relevant regulated industry. Further, **there seems to be little point in attempting to estimate the yield on a bond which is not commonly issued**" [emphasis added].[217]

The Authority notes that current bond market conditions are significantly different from those in the past. The Australian bond market is very illiquid for long-term bonds with terms to maturity of 5 years and above, with insufficient numbers of bonds traded in the market to generate reliable industry-wide estimates. This is the reason why CBASpectrum decided to cease publishing its estimates of the fair yield curves for Australian corporate bonds.[218] Similarly, Bloomberg has shortened the duration of bonds in which their fair yield curves are derived across different credit ratings.

[217] Australian Competition Tribunal, *Application by ActewAGL Distribution [2010] ACompT 4*, 17 September 2010

[218] In its announcement, CBASpectrum states that: "Sparse and heterogenic data have always made it difficult to produce a broad range of reliable credit curves in Australia. CBASpectrum has sought to overcome this problem in the past through the use of a number of econometric variables and assumptions that take account of additional information such as implied default rates, sector composition, historical relativities and

The AER's method

In its recent Final Decision on the Victorian electricity distribution businesses in October 2010,[219] the AER adopted a new approach to estimating the debt risk premium. In this approach, the debt risk premium is derived as the weighted average of the Australian Pipeline Trust (**APT**) bond, which is assigned a 25 per cent weight, and an extrapolation of the Bloomberg 7-year BBB fair yield curve to 10-years, which is assigned a 75 per cent weight. The Bloomberg 7-year BBB fair yield curve is extrapolated to a 10-year BBB fair yield curve using the spread between 10-year AAA and 7-year AAA Australian corporate bonds in June 2010 – the last month Bloomberg produced these two AAA fair yield curves. The rationale for the AER's new approach is summarised below.

First, the AER considered the APT bond (APT is the financing arm of APA Group, a gas transmission and distribution network service provider). This 10-year BBB rated bond was issued by the APT in July 2010. The AER is of the view that, prima facie, the APT bond represents a useful benchmark corporate bond rate because it reflects a 10-year maturity, and provides an acceptable proxy for the BBB+ credit rating. The AER considered that the nature of the investments and markets by the APA Group provide a close match to those of electricity network service providers.

Second, the AER considered the reliability of independent estimates of fair yields by Bloomberg, together with the uncertainty surrounding the APT bond as a single observation. The AER is of the view that it is appropriate to use the yields derived from the Bloomberg 7-year BBB fair yield and the spread between the 10-year and 7-year AAA fair yields to extrapolate to a 10-year term. The AER considered that this 10-year fair yield estimate should be used together with the APT bond, to estimate the debt risk premium for its Final Decision on Victorian electricity DNSPs.

Third, the AER is of the view that more weight should be given to the Bloomberg's fair yield curve than the APT bond. The AER considers that Bloomberg accurately represents yields on shorter rated BBB bonds (e.g. 7 years). On the other hand, the yield on the APT bond reflects a directly observed yield for one specific 10-year BBB bond, notwithstanding that it may be reflective of the efficient cost of debt for regulated network service providers. Accordingly, the AER considered that a 75 per cent weighting for Bloomberg and a 25 per cent weighting for APT is appropriate to reflect a reasonable and practical approach in setting the debt risk premium.

It should be noted that the 10-year and 7-year AAA fair yields are no longer provided by Bloomberg. The Authority notes the AER's recently revised approach in its Final Decision on Victorian electricity DNSPs, relying on the use of 10-year and 7-year AAA fair yield curves (which are no longer available), will be increasingly unrelated to the prevailing conditions in the market for funds.

IPART's proposed method

IPART recently released its discussion paper seeking comments from stakeholders on its proposed method to estimate the debt margin (or debt risk premium). Three key points from the IPART's paper are summarised below:

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spread performance of other rating bands. However, disparity of the data has increased and many of these relationships have changed over the past few years, meaning that reliability of the models designed to indicate where various credits should trade has receded. Users have also tended to confuse these fair value estimates with alternative models estimating where generic credit curves have actually traded and used the data for purposes other than relative value analysis".

[219] Australian Energy Regulator, October 2010, Victorian electricity distribution network service providers: Distribution determination 2011 – 2015, pp472-584

- the data source;
- the statistical approach; and
- the term to maturity.

In considering the data source, IPART is of the view that the Australian and US bond markets appear to be the most appropriate markets to access when making its regulatory decisions. In addition, IPART suggests that the Bloomberg fair yield curves may be suitable if used together with other data sources.

When discussing its statistical approach IPART is of the view that using the median of the sample of bonds tends to be more appropriate than using upper, lower and midpoint values, which was its previous approach.

In determining the appropriate term to maturity, IPART is indicating that it is considering shortening the term to maturity of bonds which are used to derive the debt risk premium, from 10 years to the term that matches the regulatory period.

IPART has not yet decided on the method to be used to calculate the debt risk premium for its future regulatory decisions. However, the above three factors appear to be the most important considerations for IPART.

The Authority's intended approach: A bond yield approach

After careful consideration of the Tribunal's decision on the ActewAGL matter in September 2010, the most recent AER's Final Decision on Victorian electricity DNSPs in October 2010, and IPART's discussion paper on debt margin in November 2010, the Authority considers that:

- extrapolation to a 10-year term based on estimates of the fair yield curves available from Bloomberg is problematic because it could add significant inaccuracy in and inconsistency across regulatory decisions;
- the lack of observable bonds with terms to maturity of 10 years warrants a broader sample of bonds with varying terms for deriving the debt risk premium; and
- the 10-year BBB APT bond is a relevant benchmark but should not be the only benchmark in determining a debt risk premium commensurate with the prevailing conditions in the market for funds and the risks involved in providing reference services.

In the Discussion Paper, the Authority proposed to discontinue the previous practice of basing the debt risk premium on a 10-year corporate bond using Bloomberg's extrapolated data but rather to base the debt risk premium on a sample of bond yields of varying terms to maturity.

The Authority favours the use of the bond-yield approach, which relies on bond yields observed directly from the Australian financial market. The Authority is not persuaded that bond markets in other countries should be used to inform this analysis. The Authority has consistently used data from the Australian financial market to estimate the WACC parameters. As such, foreign investors are only recognised to the extent that they invest in the domestic market. This means that the weighting given to foreign investors should be based on their domestic level of wealth and not on their global level of wealth. Under this framework, the aggregate amount of wealth is that amount invested in the domestic market portfolio. Wealth invested outside of the domestic market is outside the model and, as such, plays no role in the pricing of domestic assets.[220]

Australian financial data has been consistently used by Australian regulators to estimate the debt risk premium as well as other WACC parameters. As such, the Authority does not intend to depart from this current practice.[221]

Consistency versus market relevance

Given the current condition of the Australian bond market, the Authority notes that most Australian corporate bonds currently traded in the market have a maturity term well below 10 years. The Authority has considered the trade-off between:

- consistency between the debt risk premium and other WACC parameters, such as the nominal risk free rate and expected inflation, in terms of a 10-year term; and
- how well the estimates of the debt risk premium are commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services ("market relevance").

The Authority is of the view that the market relevance of the estimates of the debt risk premium should carry more weight than the requirement of consistency with other WACC parameters. The reasons for this are twofold.

First, attempting to maintain consistency with other WACC parameters is likely to have reduced the level of market relevance, and this relevance is likely to be further compromised in the future.

In this regard, there is an inherent instability in the process of extrapolating from Bloomberg's 7-year BBB to the 10-year BBB fair yield curve. The current approach by the AER is to use the spread between the 10-year AAA and 7-year AAA fair yields. It is noted that Bloomberg ceased publishing fair yield curves for both 10-year AAA and 7-year AAA fair yield curves on 22 June 2010. Additionally, the use of 10-year and 7-year AAA fair yield curves for Australian corporate bonds will become increasingly outdated if used for future regulatory decisions. In the current financial environment, the Authority considers that it is possible that Bloomberg will continue to shorten its estimates of fair yield curves. As such, errors from the extrapolation approach may become even larger in the future.

Second, moving away from the 10-year term provides for a larger sample of Australian corporate bonds to be considered, which should improve the estimate of the debt risk premium. This is because any measure that relies on a small sample of data points will be less reliable than one based on a larger sample.

This view is further supported by the fact that individual Australian corporate bonds are often not traded daily in the Australian financial market. The daily bond prices provided by Bloomberg do not necessarily reflect executed trades in the market on the day. For some days when there are not enough trades in the market, the daily bond pricing from Bloomberg is only an approximate market value of the bond.

[220] Handley, J. April 2009, *Further comments on the valuation of imputation credits,* Report prepared for the AER, 15 April 2009, p17

[221] The Authority is aware that, in its recent Draft Decision on the approach to estimate the debt risk premium, IPART included bonds, issued by Australian companies in the US market, denominated in American dollars, in the sample of bonds to derive the debt risk premium for its regulated businesses.

As such, a large sample of data will provide a more reliable estimate of the debt risk premium for a benchmark firm. This is also consistent with the Tribunal's view, in its decision for the ActewAGL gas network in September 2010, that the current market does not have sufficient number of long term bonds to determine fair yields.[222]

In summary, the Authority considers that there are sufficient reasons to depart from the 10-year term adopted in previous regulatory decisions on the debt risk premium:

- First, there is a significant deviation between Bloomberg's estimate of the 7-year BBB fair yield curve and observed yields from Australian corporate bonds traded in the financial market;
- Second, Bloomberg's estimation of 10-year and 7-year AAA fair yield curves for Australian corporate bonds ceased in June 2010. The use of 10-year and 7-year AAA fair yield curves for the Australian corporate bonds will become increasingly outdated if used for future regulatory decisions.
- Third, Bloomberg has progressively shortened its estimates of the fair yield curves across credit ratings for Australian corporate bonds. The Authority considers that it is likely that Bloomberg will again shorten its estimates of fair yield curves in the future. Using the 7-year BBB fair yield curve in deriving the debt risk premium is problematic because this approach is subject to uncertain data being available from Bloomberg.
- Fourth, Bloomberg's method to estimate the fair yield curves is not disclosed to the public. As such, its estimates cannot be replicated. Using estimates of Bloomberg's estimates of fair yield curves lacks transparency.
- Fifth, CBASpectrum has recently decided to cease publishing its estimates of fair yield curves for Australian corporate bonds across all credit ratings,

The establishment of a benchmark sample of Australian corporate bonds

The Authority is of the view that each bond included in the sample of Australian corporate bonds used to derive the debt risk premium for regulated businesses should ideally satisfy three criteria. The security should ideally:

- Criterion 1: have the same Standard and Poor's credit rating as the regulated businesses (BBB/BBB+ in this case because a credit rating of BBB+ is generally adopted by regulators for regulated businesses).
- The Authority believes that it is currently appropriate to include all Australian corporate bonds within the BBB band credit rating in the sample. This also reflects a conservative approach taken by the Authority in selecting the bonds in the sample. The Authority is aware that Bloomberg has used all BBB-/BBB/BBB+, known as "BBB band", to estimate the fair yield curve for the so-called BBB fair yield curve. As such, bonds with credit rating of BBB- are also included in the sample of the bonds. However, the inclusion of bonds with BBB- credit rating would need to be subject to review over time.
- Criterion 2: be in the same industry (the regulated utility sector); and
- Criterion 3: have a maturity of two years or longer to ensure that there are sufficient bonds in the sample for the analysis. This criterion has been used by the AER and IPART.

[222] Australian Competition Tribunal, *Application by ActewAGL Distribution [2010] ACompT 4*, 17 September 2010, paragraph 72

It would be ideal to derive a sample of Australian corporate bonds that meet all three of the desirable criteria above. However, given the current state of the Australian bond market, practical (i.e. less restrictive) criteria are necessary to select a sample of the Australian corporate bonds to estimate the debt risk premium.

In particular, the Authority notes that there are only four bonds issued by the Australian energy sector which are currently traded in the financial market. The Authority examined the actual term of debt portfolios of the energy businesses as shown in Table H 5 below.

Table H 5 List of Australian corporate bonds issued by the energy sector in February 2011[223]

Name of business	S&P Credit rating	Maturity	Years to maturity as at 28 February 2011
APT	BBB	22 July 2022	9.59
Santos	BBB+	23 Sep 2015	4.76
Envestra Victoria	BBB-	14 Oct 2015	4.82
DBNGP	BBB-	29 Sep 2015	4.78
Sample average years to maturity			5.78

Source: Bloomberg and Economic Regulation Authority's analysis

The lack of liquidity in the market for corporate bonds, particularly for bonds approaching 10 year terms, suggests that the method of estimating the debt risk premium using a 10-year term is increasingly problematic.

Accordingly, the Authority proposes to adopt the following approach to determine the sample of Australian corporate bonds to be used to estimate the debt risk premium, using the "search" function from Bloomberg:

- credit rating of BBB-/BBB/BBB+ by Standard & Poor's;
- time to maturity of 2 years or longer;
- bonds issued in Australia by Australian entities and denominated in Australian dollars;
- inclusion of both fixed bonds[224] and floating bonds;[225] and
- inclusion of both Bullet and Callable/ Putable redemptions.[226]

[223] In a current sample of Australian corporate bonds as at 28 February 2011, only four bonds were issued by the energy sector. However, the inclusion ofSantos bond in the regulated energy sector is questionable.

[224] This is a long term bond that pays a fixed rate of interest (a coupon rate) over its life.

[225] This is a bond whose interest payment fluctuates in step with the market interest rates, or some other external measure. Price of floating rate bonds remains relatively stable because neither a capital gain nor capital loss occurs as market interest rates go up or down. Technically, the coupons are linked to the bank bill swap rate (BBSW) (it could also be linked to another index, such as LIBOR), but this is highly correlated with the RBA's cash rate. As such, as interest rates rise, the bondholders in floaters will be compensated with a higher coupon rate.

[226] A callable (putable) bond includes a provision in a bond contract that give the issuer (the bondholder) the right to redeem the bonds under specified terms prior to the normal maturity date. This is in contrast to a

The Authority notes that bonds issued by individual companies change over time, as does the credit rating of the company. As a result, the sample of the Australian corporate bonds will be updated for future regulatory decisions. In addition, it is noted that only bonds in the sample which are currently traded (i.e. data on fair yields available from Bloomberg) in the averaging period are included in the sample of bonds used to derive the debt risk premium.

A method to estimate the debt risk premium from a benchmark sample of Australian corporate bonds

Since bonds in the sample exhibit different characteristics, such as different industries and different terms until maturity, consideration needs to be given as to whether weights should be applied to each bond to reflect their relative importance in the sample. The weighting approaches that could be adopted are:

- a simple average (or equally weighted average);
- a "number-of-years-until-maturity" approach (in which bonds with more years to maturity are given greater weight than bonds with fewer years to maturity);
- an "amount-issued" approach (where more weight is given to bonds issued in greater amounts); and
- an approach where the median[227] of a sample is used. For a sample with an odd number of observations, the median value is the value of the single middle observation from the sample. If there is an even number of observations in the sample, then the median is calculated as the average of the two middle values.

The weighted average of yields (WAY) is defined as:

$$\text{WAY} = \sum_{i=1}^{n} w_i \overline{Y}_i;$$

where:

- n is the number of bonds in the sample;
- w_i is the weight assigned to bond i in the sample $\left(w_i = {K_i}/{K} \right)$;
- K and K_i are the total value issued (or years to maturity) and value issued (or years to maturity) of each bond, respectively, to which the weight for each bond is calculated; and
- $\overline{Y}_i$ is the average of the fair yields for bond i in the averaging period.

standard bond that is not able to be redeemed prior to maturity. A callable (putable) bond therefore has a higher (lower) yield relative to a standard bond, since there is a possibility that the bond will be redeemed by the issuer (bondholder) if market interest rates fall (rise).

[227] The median of a sample of observations is the numeric value which separates the higher half of a sample from the lower half when observations from the sample are arranged from the lowest value to the highest value.

Table H 6 BBB-/BBB/BBB+ Australian corporate bonds, February 2011

No.	Name of business	Bloomberg ticker	Coupon	Maturity	Main industry
1.	APT PIPELINES	E1325336 Corp	7.75	22/07/2020	Electric transmission[228]
2.	BANK OF QUEENSLAND LTD	EH390789 Corp	10.75	4/06/2018	Commercial Banks Non-US
3.	NEXUS AUSTRALIA	EI204253 Corp	3.6	31/08/2017	Special Purpose entity
4.	NEXUS AUSTRALIA	EI204261 Corp	3.6	31/08/2019	Special Purpose entity
5.	DBNGP FINANCE CO PTY	EI414656 Corp	8.25	29/09/2015	Gas transportation
6.	DEXUS FINANCE	EI223256 Corp	8.75	21/04/2017	Mortgage
7.	ENVESTRA VICTORIA PTY LTD	EC866427 Corp	6.25	14/10/2015	Gas distribution
8.	LEIGHTON FINANCE	EH911249 Corp	9.5	28/07/2014	Diversified financial service
9.	SYDNEY AIRPORT FINANCE	EI308853 Corp	8	6/07/2015	Finance-Other Services
10.	MIRVAC GROUP FUNDING LTD	EI195249 Corp	8.25	15/03/2015	Real Estate Oper/Development
11.	MIRVAC GROUP FINANCE LTD	EI414696 Corp	8	16/09/2016	Real Estate Oper/Development
12.	NEW TERMINAL FIN	EF641357 Corp	6.25	20/09/2016	Special Purpose entity
13.	BBI DBCT FINANCE PTY	EF461870 Corp	6.25	9/06/2016	Diversified Financial Services
14.	SANTOS FINANCE	EF102609 Corp	6.25	23/09/2015	Oil Comp-Exploration & Production
15.	WESFARMERS LTD	EH964875 Corp	8.25	11/09/2014	Retail-Misc/Diversified
16.	WESFARMERS LTD	EH964867 Corp	7.68	11/09/2014	Retail-Misc/Diversified

Source: Bloomberg

Given that the current market for bonds in Australia is relatively thin for the period until 28 February 2011, as presented in Table H 6 above, the Authority makes the following observations:

[228] This is a classification from Bloomberg. APT pipelines are generally classified as a business in a gas industry.

- When the credit rating of BBB-/BBB/BBB+ is targeted, 16 bonds satisfy Criterion 1 (the same credit rating) and Criterion 3 (maturity of two years and longer), but not Criterion 2 (the same industry as the regulated business).
- When the industry-based criterion is targeted, together with Criterion 3, only a few bonds are found (e.g. APT Pipelines and Santos).

Based on the above analyses, and to provide a broad sample, the Authority considers that it is appropriate to include all bonds which satisfy Criteria 1 and 3 in the sample of bonds.

Public submissions in response to the Authority's discussion paper on debt risk premium

In response to the Authority's Discussion Paper on Debt Risk Premium, 13 public submissions were received from the following organisations:

- Verve Energy;
- Dampier to Bunbury Natural Gas Pipeline (DBP);
- Western Australia Gas Networks (WAGN);
- Goldfields Gas Transmission (GGT);
- Western Power;
- BHP Billiton;
- Brookfield;
- WestNet Rail;
- Australian Rail Track Corporation (ARTC);
- Horizon Power;
- Alinta Gas;
- Water Corporation; and
- Western Australian Council of Social Service (WACOSS).

Key issues raised in these public submissions are discussed below.

Selection criteria: which bonds should or should not be included in the benchmark sample?

In its submission, Verve Energy suggested that the Authority monitor the inclusion of BBB- Australian corporate bonds in the benchmark sample of bonds to derive the debt risk premium. Verve Energy suggested this is to ensure that the goal of widening the capture of referable corporate debts does not change the average rating of the included businesses from BBB/BBB+. Verve Energy submitted the inclusion of BBB- bonds is likely to increase the resulting debt risk premium, inappropriately advantaging the regulated business.[229] Verve Energy also submitted that the Authority may wish to estimate the premium included in callable bonds and make adjustment from their yields when those callable bonds are included in the benchmark sample.[230]

In a similar manner, BHP Billiton submitted that the inclusion of BBB and BBB- bonds does not reflect the recognised credit ratings of regulated assets and so could be expected to result in an upwardly biased estimate of the debt risk premium for regulated businesses. BHP Billiton considered that such bonds with credit rating of BBB and BBB- should be excluded from a benchmark sample of bonds to derive the debt risk premium for regulated businesses. BHP Billiton suggested excluding callable bonds from the benchmark sample because these bonds could be expected to trade at higher yields than those without a callable redemption.[231]

Western Power and its consultant, KPMG, submitted that bonds issued by financial institutions should be removed from the benchmark sample because they have materially different capital structures to non-financial institutions. Western Power also proposed that putable bonds, hybrid securities, subordinated bonds should also be excluded from the benchmark sample.[232]

Selection criteria: cut-off point

Western Power and its consultant, KPMG, submitted that Australian infrastructure businesses tend to have a preference for, and tend to use, longer dated funding raised both in Australia (over the past 6 months) and offshore (over the past 12 months). Therefore, they argued that bond pricing observations of less than 5 years are irrelevant when determining the cost of debt for a benchmark business.[233] KPMG proposed that the Authority considers varying the criteria for the bonds included in the Authority's benchmark sample by increasing the minimum term to maturity to 5 years.[234] KPMG argued that Australian infrastructure businesses such as Toll, Asciano, AGL, Energy Gas Partnerships, United Energy Distribution, Electranet and Envestra have all sourced 5-17 year funding from offshore US markets and this is indicative of the preference for, and use of, longer dated funding.[235]

In its submission, Alinta was of the view that the absence of Australian corporate bonds with a longer term to maturity (excluding the APT bond) might be taken to indicate that the Authority's benchmark sample of corporate bonds with term to maturity less than 5 years is likely to better reflect the prevailing market conditions in the market for funds.[236] However, Alinta was cautious that this approach may inadequately compensate investors.

[229] Verve Energy, *Estimating Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p1

[230] Verve Energy, *Estimating Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p2

[231] BHP Billiton Nickel West, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p6

[232] Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, pp18-20

[233] Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p2

[234] Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p14

[235] Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p15

[236] Alinta, *Measuring Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p3

As such, Alinta proposed that the benchmark sample should exclude all corporate bonds with less-than-5-year term to maturity.[237]

DBP, in its submission, argued that market realities, together with the requirements of the NGR, dictate a move away from the "10 years to maturity" assumption.[238]

The proposed four weighting approaches

Verve Energy expressed its concern that the Authority's adoption of a conservative weighting approach, which produces the highest value of debt risk premium, would be in favour of the regulated businesses. Verve Energy proposed the Authority adopt the most neutral position in considering the weighting approach adopted.[239]

BHP Billiton submitted that adopting the highest outcome of the proposed four approaches would be inconsistent with the requirement of the NGL. BHP Billiton proposed the selection of the most appropriate approach should be made by detailed reviews of all aspects of each approach, and not purely on taking a conservative approach.[240]

Illiquidity of bonds in the Authority's benchmark sample

In its submission, Australian Rail Track Corporation (**ARTC**) submitted that Bloomberg may not be including certain BBB bonds in the sample it uses to construct its fair value curves if the bonds are not well priced (i.e. illiquid). The ARCT also submitted that the Authority has not considered why certain bonds in its benchmark sample are not referenced in Bloomberg's sample.[241] Brookfield expressed its similar concern – the lack of liquidity in the corporate bond market.[242]

Goldfields Gas Transmission (**GGT**), and its consultant Synergies Economic Consulting (**Synergies**), submitted that the Authority does not consider the liquidity characteristics of the bonds in its benchmark sample. Synergies argued that Bloomberg only includes liquid bonds to produce a reliable estimation of the fair value curves and that, to be well-priced, the bond must be liquid to ensure that the price is reliable.[243]

1. GGT and Synergies also submitted that the APT bond was excluded by Bloomberg in the sample used to construct its estimate of fair value curves as at 31 December 2010. The reason for this exclusion was that the price of the APT bond is an indicative price and due to a lack of liquidity in the bond, the price is not considered to be a reliable price.[244]

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[237] Alinta, *Measuring Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p4

[238] DBP, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p14

[239] Verve Energy, *Estimating Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p2

[240] BHP Billiton Nickel West, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p7

[241] Australian Rail Track Corporation, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, pp3-4

[242] Brookfield, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p3

[243] GGT, and Synergies' supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p11

[244] GGT, and Synergies' supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p16

Horizon Power and its consultant, Economic Insight, submitted that if bonds issued by a regulated entity are illiquid, then an illiquidity premium should be allowed in the cost of debt. In addition, they were of the view that an illiquidity premium needs to be derived separately and it is not useful to calculate an average of the debt risk premium based on a mix of liquid and illiquid bonds.[245]

Inconsistency of "terms to maturity"

Western Australian Gas Networks (**WAGN**) expressed its concern that it is unclear about the way in which the nominal risk free rate is to be determined. WAGN submitted that there is obvious inconsistency in that the debt risk premium is obtained as the difference between the weighted average yields of bonds, which is less-than-10-year term to maturity, and the nominal risk free rate over the same sampling period, which is 10-year term to maturity.[246]

Western Power and its consultant, KPMG, argued that there is an inconsistency issue with regard to terms to maturity. They submitted that subtracting a shorter dated security from a longer dated base/risk free rate is expected to systematically understate the DRP, possibly by a material amount, depending on the shape of the underlying yield curve.[247]

Retrospective analysis

BHP Billiton submits that a retrospective analysis should be undertaken using historical data that compares the results from the Authority's intended approach with that from Bloomberg's estimate of the fair value curve for the same period of time with the purpose of providing insights into any deficiencies or biases of the intended approach.[248]

Authority consideration

For the ease of the discussion, the Authority considers, in turn, each of the above issues raised in the public submissions in response to the Authority's Discussion Paper on Debt Risk Premium in December 2010.

Selection criteria: which bonds should or should not be included in the benchmark sample?

The Authority agrees that inclusion of BBB and BBB- Australian corporate bonds in the benchmark sample used to derive the debt risk premium should be closely monitored. The benchmark credit rating for regulated businesses is generally BBB+ therefore inclusion of BBB- and BBB bonds may systematically overestimate the debt risk premium. However, given that the Australian bond market is currently very thin, the Authority is of the view that inclusion of all credit rating bonds within the BBB band is warranted to ensure there are sufficient bonds available for the benchmark sample.

In addition, the Authority is of the view that using a large, heterogeneous source of data is likely to provide a more reliable estimate of the debt risk premium. A sample size of data is also used to determine the confidence level of an estimate.

[245] Horizon Power and Economic Insight's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p8

[246] Western Australian Gas Networks, response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p8

[247] Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p15

[248] BHP Billiton Nickel West, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, pp4-5

The Authority also notes that the AER has used a sample of Australian corporate bonds with terms to maturity of less than ten years to test whether estimates of fair yield curves from Bloomberg or CBASpectrum fit better with observed yields of the bonds in the sample.

The Authority is aware of the limitations of including bonds from different industries, of less than 10 years term to maturity and with callable/putable redemption in the benchmark sample. However, as previously discussed, the Authority is of the view that a large sample of bonds will likely result in a better estimate of the debt risk premium which is then applied to regulated businesses. In addition, the key strengths for the bond yield approach are its “market relevance”, simplicity, and transparency. As a result, putting too many constraints on the selection criteria will add unnecessary and arguable complexities into the approach.

Selection criteria: cut-off point

The Authority agrees that the average term to maturity for the benchmark sample should ideally be a 10-year term. However, given the very thin Australian bond market at the present time, the cut-off of terms to maturity of 2 years for individual bonds to be included in the sample seems reasonable to ensure that there are enough bonds included in the benchmark sample. Other Australian regulators including the AER and IPART used the cut-off of 2 years terms to maturity in their previous decisions as noted above. The average term to maturity of the 16 bonds in the benchmark sample is 5.43 years even though the cut-off term is 2 years.

The proposed four weighting approaches

The Authority notes that Verve Energy and BHP Billiton argue that adopting the highest estimate of the debt risk premium among four weighting approaches would be in favour of the regulated businesses. The Authority is of the view that it is appropriate to assume that bonds with longer term to maturity should be given greater weight than bonds with shorter term to maturity to derive a weighted average for the benchmark sample. This view is also consistent with the finance principle: a risk and return trade-off. As a result, the Authority considers that a weighted average approach using term to maturity of the bonds should be used.

Illiquidity of bonds in the benchmark sample

The Authority is aware that some of the bonds included in the benchmark sample used in the ERA’s bond yield approach are not referenced by Bloomberg to construct its fair value curves.

Table H 7 BBB-/BBB/BBB+ Australian corporate bonds used by Bloomberg and by the Authority, February 2011

No.	Bonds only in the Sample used by the ERA's Bond Yield Approach	Bonds in common in both samples	Bonds only in the Sample used by Bloomberg's Fair Yield Approach
1.	APT PIPELINES LTD (2020)	LEIGHTON FINANCE LTD	PUBL & BROAD FINANCE LTD (2011)
2.	BANK OF QUEENSLAND LTD (2018)	WESFARMERS LTD	ENERGY PARTNERSHIP GAS (2011)
3.	NEXUS AUSTRALIA MGT (2017)	MIRVAC GROUP FUNDING LTD	TRANSURBAN FINANCE CMPNY (2011)
4.	NEXUS AUSTRALIA MGT (2019)	NEW TERMINAL FINANCING	ORIGIN ENERGY LIMITED (2011)
5.	DEXUS FINANCE PTY LTD (2017	SANTOS FINANCE LIMITED	TABCORP INVESTMENT NO 4 (2011)
6.	ENVESTRA VICTORIA PTY LT (2015)	DBNGP FINANCE CO PTY	CLP AUSTRALIA FINANCE (2012)
7.	SYDNEY AIRPORT FINANCE (2015)	BBI DBCT FINANCE PTY	COLES GROUP FINANCE (2012)
8.		MIRVAC GROUP FINANCE LTD	HOLCIM FINANCE AUSTRALIA (2012)
9.			TRANSURBAN FINANCE CO PT (2014)
10.			SNOWY HYDRO LIMITED (2013)

Source: Bloomberg and Authority's analysis

The Authority notes that 10 bonds used by Bloomberg to construct its estimates of the fair value curves are not included in the Authority's benchmark sample. Out of these 10 bonds, 8 bonds are excluded because they have terms to maturity of less than the "a minimum of 2 years term to maturity" criteria stated in the Authority's bond yield approach. The two bonds issued by Transurban Finance were not included in the Authority's benchmark sample to estimate the DRP. The Authority believes that the main reason for this is that this company is assigned with a credit rating of A- by S&P.

The Authority notes that bond prices from Bloomberg's data terminal can be categorised into three different groups:

- Indicative prices
- Executable prices
- Traded prices

Indicative prices account for nearly 90 per cent of the bond prices available on the Bloomberg bond database. Since market makers have no obligation to execute trades at indicative prices, it is not unusual to find indicative prices being very different to actual market prices.[249]

Executable prices are available only for bonds traded on some electronic trading platforms. However, most electronic trading platforms only offer executable prices to non-competitors and the subscription costs of accessing executable prices could be very expensive.

The Authority also notes that around 10,000 bonds out of 510,000 bonds on Bloomberg database currently have Composite Bloomberg Bond Trader (**CBBT**) prices, which are Bloomberg Generic (**BGN**) prices based on executable prices.[250]

The Authority is aware that only bonds with BGN are included in the sample of bonds that is used in the Bloomberg's estimates of the fair value curves. BGN price is the simple average price of all kinds of prices, including indicative prices and executable prices, quoted by Bloomberg's price contributors over a specified time window. Bloomberg also states that the availability of the BGN price for a bond is an indication of good liquidity for that bond and in some cases, bond prices from a specific pricing source are used in lieu of BGN prices (e.g. fixing prices).

The Authority notes that 10 out of 16 bonds have BGN pricing data in the Authority's benchmark sample of Australian corporate bonds for the period until 28 February 2011. The six bonds that do not have BGN pricing data for the period considered include bonds issued by APT (mature in 2020); Nexus Australia (2017); Nexus Australia (2019); Dexus Finance (2017); Envestra Victoria (2015); and Wesfarmers (2014 Floating bond).

The Authority notes that, when the option of "CBBT Only" (i.e. include liquid bonds only) is selected from Bloomberg' search, together with all selection criteria stated in the Discussion Paper on Debt Risk Premium, only one bond issued by Mirvac Group Finance (2016) has CBBT pricing data. This bond is included in the Authority's benchmark sample of Australian corporate bonds to estimate the DRP.

As the Australian corporate bond market is very thin and illiquid at the moment the Authority is of the view that indicative prices are the best estimates of the market values of bond prices.

[249] Lee, M. (2007), *Bloomberg Fair Value Market Curves,* presentation at International Bond Market Conference 2007, Taipei, available at www.taipeibond.gretai.org.tw, accessed on 21 November 2010 or search from www.google.com.au

[250] Lee, M. (2007), *Bloomberg Fair Value Market Curves,* presentation at International Bond Market Conference 2007, Taipei, available at www.taipeibond.gretai.org.tw, accessed on 21 November 2010 or search from www.google.com.au

Inconsistency of "terms to maturity"

The Authority agrees that there is an inconsistency when the debt risk premium is calculated as the difference between bond yields with less-than-10-year term to maturity and the 10-year CGS as a risk free rate. As such, the Authority has decided to adjust the 10-year Commonwealth Government Securities (**CGS**) rates to be consistent with the term to maturity for each of the 16 bonds in the benchmark sample.

The Authority considers that the estimated nominal risk free rate of return should be 5.35 per cent, for the period until 28 February 2011. This nominal risk free rate is estimated for a 5-year CGS bonds. The same principle is applied to estimate the risk free rate for Australian corporate bonds with more-than-5-year term to maturity. The risk free rate for 5-year CGS must be adjusted to reflect the fact that bonds in the benchmark sample have longer-than-5-year term to maturity.

For example, column (5) from Table H 8 shows that the nominal risk free rate for the APT bond with 9.39 years to maturity is 5.695 per cent for the period till 28 February 2011. By comparison, the nominal risk free rate for the APT bond, which will be used to estimate the debt risk premium for this bond, is higher than the risk free rate for a 5-year CGS bonds. This is consistent with the finance principle of risk and return trade-off: for longer investments with higher risks, then higher returns are required.

Table H 8 Observed yields, adjusted nominal risk free rates and debt risk premium for BBB-/BBB/BBB+ Australian corporate bonds, for the period to 28 February 2011 (per cent)

No.	Bond	Term to maturity as at 28 February 2011 (years)	Observed yields (per cent)	Risk Free Rate (per cent)	Debt Risk Premium (per cent)
1	APT PIPELINES LTD	9.39	8.487	5.695	2.792
2	BANK OF QUEENSLAND LTD	7.26	8.536	5.642	2.893
3	NEXUS AUSTRALIA MGT	6.50	9.494	5.597	3.896
4	NEXUS AUSTRALIA MGT	8.50	9.666	5.671	3.994
5	DBNGP FINANCE CO PTY	4.58	8.718	5.420	3.297
6	DEXUS FINANCE PTY LTD	6.14	8.479	5.566	2.913
7	ENVESTRA VICTORIA PTY LT	4.62	6.723	5.424	1.298
8	LEIGHTON FINANCE LTD	3.41	8.776	5.320	3.457
9	SYDNEY AIRPORT FINANCE	4.35	8.389	5.396	2.994
10	MIRVAC GROUP FUNDING LTD	4.04	8.061	5.374	2.687
11	MIRVAC GROUP FINANCE LTD	5.54	8.349	5.516	2.833
12	NEW TERMINAL FINANCING C	5.56	9.042	5.518	3.524
13	BBI DBCT FINANCE PTY	5.28	10.273	5.494	4.779
14	SANTOS FINANCE LIMITED	4.56	6.939	5.418	1.521
15	WESFARMERS LTD	3.53	6.990	5.340	1.650
16	WESFARMERS LTD	3.53	7.011	5.340	1.671

Source: Authority's calculations

Retrospective analysis

The Authority has also carried out the retrospective analysis (or backdated test) of the bond yield approach for the period from November 2005 to October 2007 – the latest period Bloomberg' estimate of its fair yield curve for 10-year BBB Australian corporate bonds was available.

By using all the selection criteria stated in the bond yield approach and searching on the Bloomberg data terminal, 67 Australian corporate bonds were found. Of these, only 14 bonds have historical pricing data. Most of the 14 bonds only have pricing data for the period from 29 March 2007 to 13 September 2007. As a result, the Authority is of the view that the period where data was available for all 14 bonds should be used to conduct a backdated test.

Three floating bonds are Bendigo and Adelaide Bank; CLP Australia Finance; and Santos Finance Limited (mature in 2011). Their traded margins are converted into annualised fixed equivalent yield to maturity.

Australian corporate bonds that satisfy all the selection criteria for the bond yield approach are presented in Table H 9 below.

Table H 9 BBB-/BBB/BBB+ corporate bonds, March-September 2010

No.	Name of business	Bloomberg ticker	Coupon	Maturity
1.	BENDIGO AND ADELAIDE BK	EG297494 Corp	5.3667	28/03/2012
2.	CLP AUSTRALIA FINANCE	EF167972 Corp	5.57	16/11/2012
3.	CLP AUSTRALIA FINANCE	EF167960 Corp	6.25	16/11/2012
4.	PUBL & BROAD FINANCE LTD	ED928366 Corp	6.28	6/05/2011
5.	ENERGY PARTNERSHIP GAS	ED554437 Corp	6.375	29/07/2011
6.	DEXUS FINANCE PTY LTD	EG150658 Corp	6.75	8/02/2011
7.	NEW TERMINAL FINANCING C	EF641357 Corp	6.25	20/09/2016
8.	ORIGIN ENERGY LIMITED	EF736322 Corp	6.5	6/10/2011
9.	BBI DBCT FINANCE PTY	EF461870 Corp	6.25	9/06/2016
10.	SNOWY HYDRO LIMITED	EC870795 Corp	6.5	25/02/2013
11.	SANTOS FINANCE LIMITED	EF100832 Corp	5.44	23/09/2011
12.	SANTOS FINANCE LIMITED	EF102609 Corp	6.25	23/09/2015
13.	TABCORP INVESTMENT NO 4	ED640649 Corp	6.5	13/10/2011
14.	COLES GROUP FINANCE	EF023185 Corp	6	25/07/2012

Source: Bloomberg

The result for the backdated test for the Authority's bond yield approach and Bloomberg's estimate of the fair yield curve for 10-year BBB Australian corporate bonds for the period from 29 March 2007 to 13 September 2007 can be summarised in Table H 10 below.

Table H 10 Backdated test: Bond yield approach vs. Bloomberg's estimate of fair yield for 10-year BBB bonds, (per cent)

Bond Sample	Bond Yield Approach	Bloomberg's fair yield for 10-year BBB bonds	Difference
All 14 bonds	0.989	1.326	0.336
11 bonds (exclude 3 floating bonds)	1.192	1.326	0.133

Source: Authority's calculations

The Authority notes that the difference between the bond yield approach and Bloomberg's estimate of 10-year BBB fair yield for the period March-September 2007 is 0.336 per cent. In comparison, when the debt risk premium derived from the bond yield approach is compared with Bloomberg's estimate of 7-year BBB fair yield for the November-December 2010 period, the difference is more than one per cent.

In addition, for the backdated test, the difference is getting smaller, at only 13 basis points, when all three floating bonds, namely Bendigo and Adelaide Bank (2012); CLP Australia Finance (2012); and Santos Finance (2011) are excluded from the benchmark sample

(Bloomberg does not include floating bonds in the sample to construct its fair value curves).

This backdated test provides further evidence on the robustness of the bond yield approach. As a result, the Authority is of the view that the bond yield approach should be used to estimate the debt risk premium for regulated businesses.

Draft Decision on debt risk premium

The Authority considered four scenarios regarding the bond yield approach based on the public submissions received in response to the Authority's Discussion Paper on debt risk premium:

- A full sample of 16 Australian corporate bonds (Scenario 1);
- A shortened sample excluding all bonds with BBB- credit rating (Scenario 2);
- A shortened sample excluding all bonds with less-than-5-year term to maturity (Scenario 3);
- A shortened sample excluding all bonds with BBB- credit rating and all bonds with less-than-5-year term to maturity (Scenario 4).

For each of the four scenarios above, the following four weighted average methods, which were previously discussed, are considered:

- a simple average;
- a term-to-maturity weighted average approach;
- an amount-issued weighted average approach; and
- a median approach.

The debt risk premiums calculated under the different scenarios and different weighted average approach are summarised in Table H 11 below.

Table H 11 Debt risk premiums under various scenarios and weighted average approach, (per cent) as at 28 February 2011

Weighted Average Method	Scenario 1 (16 bonds)	Scenario 2 (12 bonds)	Scenario 3 (8 bonds)	Scenario 4 (6 bonds)	Simple Average of all 4 scenarios
Simple Average	2.888	2.810	3.453	3.289	3.110
Term to Maturity Weighted Average	2.999	2.875	3.413	3.207	3.124
Amount Issued Weighted Average	2.922	2.760	3.371	3.172	3.056
Median	2.903	2.863	3.218	2.903	2.972

Source: Authority's calculations

The Authority is of the view that the best estimate of the debt risk premium for Horizon Power is to use the term to maturity weighted average: bonds in the benchmark sample with longer term to maturity will be assigned higher weight, and as a result, account for more significance in the value of debt risk premium for the sample. This view is consistent with a basis finance principle in which investment in a longer term is expected to be compensated with higher return.

The Authority is of the view that a simple average of the term to maturity weighted average of all four scenarios is likely to reflect the current conditions for market for funds.

As a result, for the 20 trading day period till 28 February 2011 for the Final Report for Horizon Power, the Authority is of the view that the debt risk premium of 3.124 per cent is reasonable.

The adoption of the debt risk premium of 3.124 per cent would also reflect a conservative position. The Authority views this decision as conservative because:

- the sample of 16 bonds observed from the market includes bonds with the feature of "Callable" redemption which, in principle, require a higher yield to compensate bondholders. The bonds issued by the Bank of Queensland Ltd and BBI DBCT Finance Pty are callable bonds. There are no bonds issued with the feature of "Putable" redemption. It is unlikely that there will be bonds with the feature of "Putable" redemption issued in the Australian bond market in the foreseeable future;
- the sample of Australian corporate bonds includes BBB and BBB- bonds which, in principle, have higher yields in comparison with BBB+ credit rating bonds for regulated business; and
- the regulated businesses have access to bank finance which, currently, is likely to be a lower cost of borrowing in comparison with bond yields.

Debt raising costs

Debt raising costs may include underwriting fees, legal fees, company credit rating fees and any other costs incurred in raising debt finance. In practice, regulators across Australia have typically included an allowance of 12.5 basis points for these costs in the cost of debt as an increment to the debt margin.

The current allowance for debt raising costs of 12.5 basis points is based upon a benchmark analysis conducted by the Allen Consulting Group (**ACG**) in 2004.[251] The ACG undertook a study for the ACCC in 2004 on appropriate debt and equity raising costs to be included in costs recognised for the purposes of determining regulated revenues and prices. This study determined debt raising costs based on long-term bond issues, consistent with the assumptions applied in determining the costs of debt for a benchmark regulated entity. Debt raising costs were based on costs associated with Australian international bond issues and for Australian medium term notes sold jointly in Australia and overseas. Estimates of these costs were equivalent to 8 to 10.4 basis points per annum when expressed as an increment to the debt margin.[252]

The Authority's decision is not only based on the ACG 2004 study, which provided the debt of raising cost of 12.5 basis points, but also on the evidence recently provided to the AER by Associate Professor Handley from the University of Melbourne in April 2010.[253] The Authority is also of the view that an allowance of 12.5 basis points provides regulatory certainty given that this amount has been widely used in the past by Australian regulators.

In conclusion, the Authority is of the view that an allowance for debt raising costs of 12.5 basis points is appropriate to be included in the debt risk premium to calculate the total cost of debt for DBP.

The Authority considers that a reasonable cost of debt is 9.0 per cent, including the debt risk premium of 3.124 percent for BBB+ as at 28 February 2011 derived using Bloomberg data for a sample of Australian corporate bonds; an allowance for debt raising costs of 0.125 per cent; and the nominal risk free rate of 5.71 per cent.

Gearing

Horizon Power's proposal

Deloitte considers that the gearing level of 60 per cent is the efficient level of gearing for Horizon Power.[254]

Authority's comments

Gearing refers to the proportions of the value of the regulated business assumed to be financed by debt and equity. Financial gearing refers to the ratio of debt to total asset value. The relative proportions of debt and equity that a firm has outstanding constitute its capital structure. The capital structure choices differ across industries, as well as for different companies within the same industry.

[251] Allen Consulting Group, December 2004, Debt and equity raising transaction costs: Final report to ACCC.

[252] Allen Consulting Group, December 2004, Debt and Equity raising transaction costs: Final report to ACCC.

[253] Handley, J., April 2010, *A Note on the Completion Method*, Report prepared for the Australian Energy Regulator

[254] Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p11

The benchmark gearing ratio is considered to be the capital structure of a benchmark efficient utility business. The Authority assumes that the regulated business tends towards the benchmark gearing level in long-run. As the optimal level of gearing is not directly observable, the 60/40 gearing level is derived from the average of actual gearing levels from a group of comparable firms.[255] The actual proportion of debt and equity for each business is dynamic and depends on a number of business-specific factors.

The Authority agrees that Horizon Power's proposed the gearing level of 60 per cent is consistent with the approach taken in relation to the current Access Arrangement and the approach taken in the AER electricity WACC Review, as well as being otherwise consistent with regulatory precedent and with observed levels of gearing of Australian pipeline companies.

The Authority approves Horizon's proposal that the appropriate debt to total assets ratio (gearing level) is 60 per cent and the equity to total assets ratio is 40 per cent.

Corporate Tax Rate

Horizon Power's proposal

Horizon Power proposes to adopt the current corporate tax rate of 30 per cent to calculate a pre-tax WACC.[256]

Authority's comments

There has been some debate amongst regulators as to whether WACC determinations should use the statutory corporate tax rate (30 per cent), or effective tax rates.[257] Many companies have effective tax rates that are well below the statutory rate and there is a risk that using the statutory tax rate will overestimate the returns required by companies to meet tax obligations. However, verifying an individual company's effective tax rate would require modelling of taxation cash flows. The benefit of using the statutory rate as a benchmark assumption is that it is simple to apply.

The Authority has in previous WACC determinations assumed the effective taxation rate of the utility businesses to be equal to the statutory rate of corporate income tax.

The Authority agrees with Horizon Power's proposal with respect to the corporate tax rate of 30 per cent.

Value of Imputation Credits (Gamma)

Horizon Power's proposal

Deloitte is of the view that the WACC for Horizon Power should not be adjusted for the impact of imputation credits because Horizon Power is a government owned entity.[258] As such, tax benefits attached to frank dividends cannot be realised by the government.

255 Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters

256 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p11

257 IPART, 2002, The weighted average cost of capital (WACC): Discussion paper

258 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p10

Authority's comments

A full imputation tax system for companies has been adopted in Australia since 1 July 1987. While Australia and New Zealand have full imputation tax systems (which are discussed below), many other countries have a partial imputation system, where only partial credit is given for the company tax.

Under the tax system of dividend imputation, a franking credit is received by Australian resident shareholders, when determining their personal income taxation liabilities, for corporate taxation paid at the company level. In a dividend imputation tax system, the proportion of company tax that can be fully rebated (credited) against personal tax liabilities is best viewed as personal income tax collected at the company level. With the full imputation tax system in Australia, the company tax (corporate income tax) is effectively eliminated if all the franking values are used as credits against personal income tax liabilities.

It is widely accepted that the approach adopted by regulators across Australia to define the value of imputation credits, known as "gamma" (γ), is in accordance with the Monkhouse definition.[259] There are two components of gamma:

- the payout ratio (F); and
- theta (θ).

As a result, the actual value of franking credits, represented in the WACC by the parameter 'gamma', depends on the proportion of (i) the franking credits that are created by the firm and that are distributed (the payout ratio, F); and (ii) the value that the investor attaches to the credit (theta), which depends on the investor's tax circumstances (that is, their marginal tax rate). As these will differ across investors, the value of franking credits may be between nil and full value (i.e. a gamma value between zero and one). A low value of gamma implies that shareholders do not obtain much relief from corporate taxation through imputation credits and therefore require a higher pre-tax income in order to justify investment.

In considering the value of imputation credits, the Authority has had regard to the detailed consideration given by the AER to this element of the WACC calculation.[260]

Payout ratio (F)

The AER has previously adopted a distribution rate (F) of 1.0, reflecting advice that this assumption is consistent with a standard assumption of valuation practice that all free cash flows are paid out to investors.[261] On this basis, the AER has rejected the use of

[259] Monkhouse, P. 'Adapting the APV Valuation Methodology and the Beta Gearing Formula to the Dividend Imputation Tax System', *Accounting and Finance*, 37, vol. 1, 1997, pp 69-88

[260] Australian Energy Regulator, December 2008, *Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, pp287–340. Australian Energy Regulator, May 2009, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, pp393–469

[261] Australian Energy Regulator, December 2008, *Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, p302

empirically observed market average distribution ratios. Advice to the AER also indicates that an assumed distribution rate of 1.0 is consistent with the Officer WACC.[262]

In addition, the AER noted that the Officer WACC framework is a perpetuity framework, which includes a simplifying assumption that cash flows occur in perpetuity and are therefore fully distributed at the end of each period. The AER accepted the advice of its consultant, Associate Professor Handley, and noted that it would be inconsistent to assume that there is a full distribution of a service provider's free cash flow but not a full distribution of the imputation credits associated with that free cash flow.

The AER considers that the assumption of a zero value for retained imputation credits is inconsistent with the Officer WACC framework.

The AER is also of the view that the actual payout ratio is unlikely to be significantly less than 100 per cent, based on an observed payout ratio from tax statistics of 71 per cent and the assumption that retained imputation credits have a positive value.[263]

In its recent Final Decision in October 2010 on Victorian electricity distribution network service providers, the AER adopted the range of 0.7 and 1.0 for the payout ratio.[264]

Based on the above analyses, the Authority considers that the payout ratio of 0.7 and 1.0 is appropriate.

Estimates of theta (θ)

The AER has considered two sources of information on the utilisation rate.

First, the AER has placed significant weight on an estimate of the utilisation rate (θ) of 0.57, derived in a dividend drop-off study over the period 2001 to 2004,[265] taking into account that this study:

- is directly relevant to the current imputation tax regime, assessing the value of imputation credits over the post-2000 period after changes in tax law that allowed Australian taxpayers to claim a full cash rebate for unused imputation credits;
- is able to be verified on the basis of statistical tests presented in the paper; and
- is an independent and credible published study that has been through the academic peer review process.

Second, the AER has had regard to estimates of the utilisation rate from taxation statistics, indicating a range of values of the utilisation rate, θ, from 0.67 (pre-2000) to 0.81 (post-2000) and a point estimate of 0.74.[266]

262 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, Attachment G: John C Handley, 12 November 2008, A note on the valuation of imputation credits.

263 The Australian Energy Regulator, May 2010, Final Decision, South Australia Distribution Determination, 2010-11 to 2014-15, p150

264 Australian Energy Regulator, October 2010, Victorian electricity distribution network service providers: Distribution determination 2011 – 2015, p583

265 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p327, citing Beggs, D. and Skeels C.L., 2006, Market arbitrage of cash dividends and franking credits, *The Economic Record* vol 82 no.258, p247. AER, May 2009, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp xix, 466

In addition, in its Final Decision on the South Australia Distribution Determination, the AER considered that the utilisation rate of 0.65, based on an estimate from tax statistics as well as an estimate from market prices, is better than a market-based estimate alone.[267]

The mid-point estimate of theta θ is 0.65, together with the payout ratio F of 1.0. This provides an estimate of 0.65 for gamma in all determinations after the 2009 WACC Review by the AER. In its most recent Final Decision on Victorian Electricity, the AER adopted the payout ratio of the range of 0.70 and 1.0. As such, the AER adopted the gamma of 0.50 for its Final Decision on Victorian Electricity.

The Authority has determined a value of theta on the basis of the two empirical studies: (i) the 2006 Beggs and Skeels study; and (ii) the 2008 Handley and Maheswaran study. A range of 0.37 to 0.81 was used in its Final Decision on the Proposed Revision to the Access Arrangement for the South West Interconnected Network in December 2009; and on the Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline in May 2010.

However, a more recent study by SFG Consulting in 2009, compared with the 2006 Beggs and Skeels, produced an estimated lower utilisation rate of 0.37.[268] This study used the same data as Beggs and Skeels in 2006 (which analysed data up to 10 May 2004) but analysed a further period of 28 months of data (up to 30 September 2006). This estimate was verified by one of the authors, C. Skeels, in the 2006 study by Beggs and Skeels. Skeels concluded that:

> “the only reasonable conclusion to be drawn is that the extended data set should yield more accurate parameter estimates for the 1 July 2000 onwards sub-sample than does the shorter data set.” [269]

The Authority notes that the AER’s view is that the 2009 SFG study is subject to methodological concerns. In its recent Final Decision for South Australia Distribution Determination in May 2010, after taking account of the advice of its consultants, Professor Michael McKenzie, Associate Professors Graham Partington (University of Sydney) and Associate Professor John Handley (University of Melbourne), the AER considers that market-based estimates of theta in the form of dividend drop-off studies are subject to significant concerns due to noise in the data and the likely effects of multi-collinearity on the regression results. Nevertheless, the Authority notes that the AER does make use of information from previous dividend drop-off studies in coming to its position on a reasonable value for the utilisation rate.

Given the uncertainty about the estimates of the utilisation rate using dividend drop-off studies and tax studies, the Authority’s position is to take a wide range of estimates of the utilisation rate. Overall, the Authority considers that a reasonable range for the value of utilisation rate is 0.37 to 0.81.

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266 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p 333, citing Handley, J. C. and Maheswaran, K., A measure of the efficacy of the Australian Imputation Tax System, *The Economic Record* vol. 84 no. 264 p.91. Australian Energy Regulator, May 2009, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. xix, xx, 466, 467

267 The Australian Energy Regulator, May 2010, Final Decision, South Australia Distribution Determination, 2010-11 to 2014-15, p.xxiv

268 SFG Consulting, 2009, The value of imputation credits as implied by the methodology of Beggs and Skeels (2006), p3

269 Skeels, C. 2009, A Review of the SFG Dividend Drop-Off Study. A report prepared for Gilbert and Tobin, p11

As a result, based on a payout ratio of a range of 0.7 and 1.0; and a theta of 0.37 and 0.81, the Authority concluded that a reasonable value of gamma, being the product of a payout ratio and theta, for this Draft Report is 0.53.

The Authority does not agree with Deloitte's proposal that the cost of capital for Horizon Power will not be adjusted for the impact of imputation credits due to the nature of regulatory regime in which a benchmark company, not a specific entity, is regulated. As such, the Authority considers that a reasonable point estimate for gamma of 0.53 should also be incorporated into the estimate of its cost of capital.

Expected Inflation

Horizon Power's proposal

No proposal on expected inflation can be found on the Deloitte's advice on WACC to Horizon Power.

Authority's comments

The Authority's approach to estimate the expected inflation is to use the geometric mean of the Reserve Bank of Australia's inflation forecasts for the next ten years. The inflation forecasts for the next two years are in the RBA's Monetary Statement which are published quarterly and the forecasts for the last eight years being the midpoint of the RBA's inflation target of 2 per cent to 3 per cent, being the midpoint of 2.5 per cent.

In the Authority's recent Final Decisions on the Proposed Access Arrangement for the Goldfields Gas Pipeline in May 2010 and on its Proposed Revisions to the Access Arrangement for the South West Interconnected Network in December 2009, the same general approach was adopted.

The Authority proposes to adopt the same approach for this Report. The forecasts on which the Authority relies for its calculations are all from the RBA's February 2011 *Statement on Monetary Policy:*[270]

- 2.50 per cent for the year to June 2011;
- 2.75 per cent for the year to June 2012;
- 3.00 per cent for the year to June 2013 and
- 2.50 per cent (being a mid-point estimate of the RBA's long term inflation forecasts) for each year from July 2014.

Using the above forecasts, the Authority has calculated the forecast inflation rate for this draft report of 2.57 per cent.

[270] Reserve Bank of Australia, August 2010, *Statement on Monetary Policy*, available at http://www.rba.gov.au/publications/smp/2011/feb/pdf/0211.pdf p62

Specific company risk premium (α)

Horizon Power's proposal

Deloitte submits that the cost of equity for Horizon Power needs to be adjusted for company specific risk factors such as company size; depth and quality of management; reliance on key customers and suppliers; product diversity; and capital structure among many others.

Deloitte argues that empirical studies do show that on average, smaller companies have higher rates of return than larger companies, which is referred to as the size premium.[271] Using the returns for different size categories from 1926 to 2007 for companies on the New York Stock Exchange (NYSE), the American Stock Exchange (AMEX) and the National Association of Securities Dealers Automated Quotation System (NASDAQ), Deloitte argues that a specific risk premium of 1.0 per cent to 1.5 per cent is appropriate for Horizon Power.

Authority's comments

The Authority does not accept it as reasonable to provide for non-systematic risks within the CAPM. This is because, under the CAPM, risks associated with returns to a particular asset could be eliminated through the holding of a well diversified portfolio of assets, and hence there is no reason to compensate for these risks. The Authority notes that appropriate parameters to the WACC calculation will be selected to give the service provider the opportunity to earn a return commensurate with the commercial risk involved.

As such, the Authority does not agree that the standard CAPM, which is used to estimate the cost of equity for Horizon Power, should be extended to take into account specific risk premium for Horizon Power. The Authority is of the view that the standard CAPM was developed on the view that only systematic risks, which cannot be diversified, are compensated. As such, the Authority considers that any modification to the standard CAPM's formula is inappropriate.

Cost of Equity

Horizon Power's proposal

On the advice from Deloitte, Horizon Power submits that standard CAPM is used to estimate the cost of equity.

Deloitte is of the view that the betas of listed companies, from both Australia and the US, that are comparable to Horizon Power are appropriate to be used in estimating beta for Horizon Power. Deloitte submits that the betas, from these selected comparable companies to Horizon Power, have been calculated based on weekly returns over a two year period and monthly returns over a four year period, compared to the relevant local accumulation index.

The main findings from Deloitte's study can be summarised as follows:

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271 Deloitte, "Horizon Power: Weighted Average Cost of Capital Analysis", 2 November 2009, p9

- the average unlevered beta for the Australian comparables in the distribution and transmission sector is 0.19 over two years on a weekly basis and 0.25 over four years on a monthly basis, compared with the average for the international comparables of 0.41 and 0.24 respectively;
- Horizon Power is involved in the distribution and transmission of electricity; however a number of the comparable companies such as APA Group, DUET Group, Envestra, AGL Resources, Enbridge, Plains All American and TransCanada are involved in the distribution and transmission of natural gas. The average unlevered beta for these companies over two years on a weekly basis and four years on a monthly basis is 0.33 and 0.28 respectively;
- the distribution and transmission comparable companies which have electricity, as well as natural gas operations, include SP Ausnet, Spark Infrastructure, Consolidated Edison, National Grid and Northeast Utilities. The average unlevered beta for these companies over two years on a weekly basis and over four years on a monthly basis is 0.29 and 0.20 respectively; and
- the average unlevered beta for the Australian comparables in the diversified energy sector is 0.61 over two years on a weekly basis and 0.49 over four years on a monthly basis, compared with the average for the international comparables of 0.45 and 0.51 respectively

In July 2010, Horizon Power commissioned another consultant, Economic Insights, to advise it on the WACC issues in responses to the Authority's issue paper. Economic Insights argues that with reference to the size of HP, there is considerable empirical evidence that supports the use of a higher value of Beta for small firms. Using a work by Booth and Smith (1985),[272] Economic Insights submits that the implied size premium could range from 0.15 to 0.24.[273]

Using the above implied size premium, Economic Insights is of the view that an equity beta of between $0.8+0.15=0.95$; and $0.8+0.24=1.04$; could be an appropriate way to accommodate the extra risk associated with the small size of Horizon Power.

Authority's comments

The Authority is of the view that using the US and other countries data in estimating the equity beta for Horizon Power is not appropriate. In addition, if the equity beta to be estimated using data from the US and other countries capital markets, all other WACC parameters such as nominal risk free rate, MRP, and inflation would also need to be derived using these data sources for consistency. This is contrary to current practices applied by Australian regulators. As such, the Authority is of the view that only Australian data should be used to estimate the equity beta.

The Authority considers that only the group of Australian companies, including APA Group; DUET Group; Envestra; SP Ausnet; and Spark Infrastructure, can be considered comparable to Horizon Power. From Deloitte's estimate, the average of unlevered beta using weekly and monthly data, for the period of June 2007 to September 2009, is 0.19 to

[272] Booth, J.R. and R.L. Smith (1985), "The Application of Errors-in-Variables Methodology to Capital Market Research: Evidence on the Small-Firm Effect", *Journal of Financial and Quantitative Analysis*, 20, 501-515.

[273] Economic Insights, "WACC Advice to Horizon Power", 20 July 2010, p7

0.25. With the corporate tax rate of 30 per cent and debt to equity ratio of 60:40, a levered beta for these estimates will be in the range of 0.4 to 0.5 which can be used the equity beta for Horizon Power.

The Authority also rejects the estimates provided by Economic Insight. The Authority considers that only one academic paper does not constitute a significant body of evidence given this study used the US data and was conducted 25 years ago. As such, its relevance to the current context of Australia is very limited. In addition, the Authority is of the view that evidence and/or data used should be for Australia.

In addition, recent estimate of equity beta reveals that equity beta of 0.4 to 0.7 is considered appropriate. In the 2009 review of WACC parameters, the AER concluded that a beta value of 0.8 is appropriate for both transmission and distribution businesses in the National Electricity Market.[274]

The Authority also adopted an equity beta of 0.8 for its recent Final Decision on Western Australia Gas Networks in February 2011 and also for its Draft Decision on Dampier Bunbury National Gas Pipeline in March 2011. The Authority also adopted the range of equity beta of 0.8 and 1.0 in its Final Decision on the proposed access arrangement for Goldfields Gas Pipeline in May 2010.

For the government-owned entities, a range of equity beta of 0.5 to 0.8 was adopted in the Authority's Final Decision on the Proposed Revisions to the Access Arrangement for the South West Interconnected Network in December 2009. In addition, the Authority adopted an equity beta of 0.65 for Water Corporate and Water Boards in its Final Report on the Inquiry into Tariffs of the Water Corporation, Aqwest and Busselton Water in June 2009.

Therefore, the Authority considers that a reasonable point estimate for equity beta is 0.7, at a gearing level of 60 per cent debt to total assets, to be adopted for Horizon Power.

Based upon the above assessment of each of the CAPM parameters, the point estimates that the Authority considers may reasonably be applied to the parameters of the CAPM in estimating the rate of return for Horizon Power are as shown in Table H 12 below.

[274] Australian Energy Regulator, May 2009. Electricity transmission and distribution network service providers, Statement of the revised WACC parameters (transmission), Statement of the revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution), p6

Table H 12 Parameter values for determination of a rate of return as at 28 February 2011 (per cent)

Parameter	Value (Per cent)
Nominal Risk Free Rate $\left(R_f\right)$	5.71
Real Risk Free Rate $\left(R_f^r\right)$	3.06
Inflation Rate π_e	2.57
Debt Proportion $\left(D\right)$	60
Equity Proportion $\left(E\right)$	40
Cost of Debt: Debt Risk Premium (DRP) (BBB+)	3.124
Cost of Debt: Debt Issuing Cost (DIC)	0.125
Cost of Debt: Risk Margin (RM)	3.249
Australian Market Risk Premium (MRP)	6
Equity Beta $\left(\beta_e\right)$	70
Corporate Tax Rate $\left(T_c\right)$	30
Franking Credit $\left(\gamma\right)$	53
Nominal Cost of Debt $\left(R_d^n\right)$	9.0
Real Cost of Debt $\left(R_d^r\right)$	6.23
Nominal Pre Tax Cost of Equity $\left(R_e^{n,\text{pre-tax}}\right)$	11.54
Real Pre Tax Cost of Equity $\left(R_e^{r,\text{pre-tax}}\right)$	8.74
Nominal After Tax Cost of Equity $\left(R_e^{n,\text{post-tax}}\right)$	9.91
Real After Tax Cost of Equity $\left(R_e^{r,\text{post-tax}}\right)$	7.16

Table H 13 Estimates of WACC (Per cent)

WACC	Value (Per cent)
Nominal Pre Tax WACC $\left(WACC_n^{\text{pre-tax}}\right)$	9.99
Real Pre Tax WACC $\left(WACC_r^{\text{pre-tax}}\right)$	7.23
Nominal After Tax WACC $\left(WACC_n^{\text{post-tax}}\right)$	9.34
Real After Tax WACC $\left(WACC_r^{\text{post-tax}}\right)$	6.60

Appendix I: Additional operating cost business cases submitted by Horizon Power

Claimed additional operating expenditure								
($m nominal)	2010	2011	2012	2013	2014	Total		
Western Power SLA (cost allocation) agreement	-	2.50	1.50	1.50	1.50	7.00		
Maint of gas supply BHP	-	-	0.50	0.50	0.50	1.50		
Uplift 09/10 to 10/11	5.96	-	-	-	-	5.96		
Other projects - Opex to support capex	-	1.91	2.11	0.82	0.62	5.45		
Wire Alert Pilot	0.03	0.53	0.04	-	-	0.60	Not allowed	Issue predominantly resolved by earlier capital project
Temporary generation	1.66	-	-	-	-	1.66		
Wood pole management	0.98	-	-	-	-	0.98		
ARCPSP2.1	0.02	0.04	0.04	0.03	0.03	0.15		
Compliance inspector - PUPP	-	0.19	0.25	0.25	0.25	0.94		
Kununurra system augmentation	-	0.25	-	-	-	0.25		
Advertising	-	0.50	0.50	0.50	0.50	2.00	Not allowed	Already included in 2009/10 base year controllable costs
Total	8.65	5.91	4.94	3.60	3.39	26.49		

Allowed additional operating expenditure								
($m real at 30/6/2009)	2010	2011	2012	2013	2014	Total		
Controllable								
Uplift 09/10 to 10/11	2.82					2.82	Partial allowance	Only allowed full costs of positions filled part way through 2009/10
Temporary generation	-1.62					-1.62	Transfer	From controllable district to non-controllable town related expenditure
Wood pole management	0.96					0.96	Allowed	Regulatory requirement for wood pole replacement
ARCPSP2.1	0.01					0.01	Partial allowance	Vacancies recognised in 2009/10
Compliance inspector - PUPP	0.24					0.24	Partial allowance	Vacancies recognised in 2009/10
Kununurra system augmentation	0.24					0.24	Allowed	Project to resolve ongoing problems in Kununurra distribution system
Sub-total controllable operating expenditure	2.66					**2.66**		
($m real at 30/6/2009)	2010	2011	2012	2013	2014	Total		
Non-controllable								
Western Power SLA (cost allocation) agreement	-	2.44	1.46	1.46	1.46	6.82	Allowed	Contract related costs
Maint of gas supply BHP	-	-	0.49	0.49	0.49	1.46	Allowed	Contract related costs
Other projects - Opex to support capex	-	1.86	2.06	0.80	0.60	5.32		
Temporary generation	1.62	-	-	-	-	1.62	Transfer	From controllable district to non-controllable town related expenditure
Sub-total non-controllable operating expenditure	1.62	4.30	4.01	2.75	2.55	**15.22**		

Appendix J: Glossary

Act	Economic Regulation Authority Act 2003
AER	Australian Economic Regulator (for the Eastern States)
AMP	Asset Management Plan
Authority	Economic Regulation Authority (Western Australia)
BCI	Building Construction Index
Biomass	Renewable organic materials, such as wood, agricultural crops or wastes, and municipal wastes, especially when used as a source of fuel or energy. Biomass can be burned directly or processed into biofuels such as ethanol and methane.
Bloomberg	Provider of financial, business and market information and data
CNG	Compressed Natural Gas
Cost-reflective Tariffs	Tariffs applying to a certain class of customers that generate revenue that exactly covers the cost of supplying electricity to that class of customers.
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CSO	Community Services Obligation
DAMPs	Horizon Power's District Asset Management Plans
Distribution	Distribution generally relates to the electricity network that extends from the zone sub-station to the customer's premises.
DORC	Depreciated Optimised Replacement Cost
DTF	Department of Treasury and Finance
DWAT	Discounted Weighted Average Tariff
ENRUP	Esperance Network Rural Upgrade Project
ERA	Economic Regulation Authority (Western Australia)
Gifted Assets	Those assets owned by the service provider but which were funded through an external source, such as developer contribution or government funding.
GSL	Guaranteed Service Level – generally these are accompanied by a penalty payment, payable to customers, who have experienced performance from an electricity supplier, below a given level.
GST	Goods and Services Tax
GTE	Government Trading Enterprise
GW	Gigawatt, 1 billion watts or 1000 megawatts
GWh	Gigawatt hour
ICB	Initial capital base
IPART	Independent Pricing and Regulatory Tribunal (in New South Wales)
IT	Information Technology
kW	Kilowatts, 1000 watts
kWh	Kilowatt hour
LNG	Liquid Natural Gas
LRMC	Long Run Marginal Cost - the change in the long-run total cost of producing a good or service resulting from a change in the quantity of output

	produced. There are no fixed inputs in the long run. As such, there is only variable cost. This means that long-run marginal cost is the result of changes in the cost of all inputs.
MBS	Metering Business Service
MRET	Mandatory Renewable Energy Target
MRP	Market risk premium
MW	Megawatts, 1 million watts or 1000 kilowatts
MWh	Megawatt hour
Network charges	The fees charged by a network operator and paid by generators and retailers for use of the network operator's network to transport electricity.
NPV	Net present value
NSW	New South Wales
NWIS	North West Interconnected System – the system of generation, network and distribution centring around Karratha and Port Hedland in the far north west of Western Australia.
OECD	Organisation for Economic Coordination and Development
ODV	Optimised Deprival Value
OoE	Office of Energy
PPAs	Power Purchase Agreements – between Horizon Power and independent generators of electricity.
PB	Parsons Brinckerhoff Australia Pty Ltd
Pre-payment meters	Electricity meters that allow customers to purchase credit and load this credit onto the pre-payment meter. The prepayment meter then allows the customer to consume electricity up to the value of the amount of the credit. Once the amount of the credit is exhausted, the pre-payment meter discontinues the supply of electricity.
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
Renewable energy	Energy that is generated from renewable sources such as wind, solar or water (hydro).
Revenue requirement	A level of revenue, to be collected from regulated tariffs, that covers the efficient costs of providing a utility service to a required performance standard.
RTIO	Rio Tinto Iron Ore
S&P	Standard and Poors
SAIDI	System Average Interruption Duration Index – the total of all customer interruptions in minutes divided by the total number of customer connections averaged over the year.
SAIFI	System Average Interruption Frequency Index – the total number of interruptions divided by the total number of customer connections averaged over the year.
SWIS	South West Interconnected System – the system of generation, networks and distribution supplying the area between Kalbarri in the north and Albany in the south and stretching out to Kalgoorlie in the east.
Synergy	The state-owned Electricity Retail Corporation, operating in the SWIS.
Transmission	Transmission generally relates to the electricity network from the generating power station to zone sub-stations, which are located at key points around

	the supply area.
TEC	Tariff Equalisation Contribution − paid by Western Power's customers through their network charges, to Horizon Power to fund the shortfall between the uniform tariff revenue and the cost of supplying electricity to customers.
Uniform Tariff	A state government policy which ensures all small use customers pay the same tariffs regardless of where they live in Western Australia.
Verve	Verve Energy − the state-owned Electricity Generation Corporation, operating in the SWIS.
WACC	Weighted Average Cost of Capital - is the minimum return that a company must earn on existing asset base to satisfy its creditors, owners, and other providers of capital, or they will invest elsewhere. It is generally calculated as the proportion of debt and equity funding used by the company compared to market risk free rates.
Watt	the SI (International System of Units) unit of power, equivalent to one joule per second and equal to the power in a circuit in which a current of one ampere flows across a potential difference of one volt.
WDV	Written down value
WEM	Wholesale Electricity Market – for the trading of electricity between generators and retailers in the SWIS.
Western Power	The state-owned Electricity Networks Corporation, operating in the SWIS.
WPC	Western Power Corporation